# Demand Forecast

## INTRODUCTION AND SUMMARY

A 20-year forecast of electricity demand is a required component of the Council's Northwest Regional Conservation and Electric Power Plan.[1] Understanding growth in electricity demand is, of course, crucial to determining the need for new electricity resources and helping assess conservation opportunities. The Council has also had a tradition of acknowledging the uncertainty of any forecast of electricity demand and developing ways to reduce the risk of planning errors that could arise from this and other uncertainties in the planning process.

Electricity demand is forecast to grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 in the medium forecast. The average annual rate of growth in this forecast is just less than 1 percent per year. This is slower demand growth than forecast in the Council's Fourth Power Plan, which grew at 1.3 percent per year from 1994 to 2015.

The slower demand growth primarily reflects reduced electricity use by the aluminum industry and other electricity intensive industries in the region. Forecasts of higher electricity and natural gas prices will fundamentally challenge energy intensive industries in the region.

The medium case electricity demand forecast means that the region's electricity needs would grow by 5,343 average megawatts by 2025, an average annual increase of 214 average megawatts. As a result of the 2000-01 energy crisis, the 2003 demand is expected to be nearly 2000 average megawatts lower than in 2000, making the annual growth rates and megawatt increases from 2003-2025 higher than from the 2000 base. The annual growth rate from 2003 to 2025 is 1.5 percent per year, with annual megawatt increases averaging 330.

Compared to the 2015 forecast of demand in the Council's Fourth Power Plan, the Fifth Plan forecast is 3,000 average megawatts lower. Nearly, two thirds of this difference is due to lower expectations for the region's aluminum smelters.

The most likely range of demand growth (between the medium-low and medium-high forecasts) is between 0.4 and 1.50 percent per year. However, the low to high forecast range recognizes that growth as low as -0.5 percent per year or as high as 2.4 percent per year is possible, although relatively unlikely. Table A-1 summarizes the forecast range.

[1] Public Law 96-501, Sec. 4(e)(3)(D)

**Table A-1: Demand Forecast Range**

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

## FORECASTING METHODS

The approach to the demand forecasts is significantly different from previous Council plans. For this plan, the Council has not used its Demand Forecasting System. Instead there are three separate approaches to the forecast in terms of methods and relationship to the Council's Fourth Power Plan. The methods differ for (1) the range of long-term non-direct service industry (non-DSI) forecasts from low to high; (2) for a monthly near-term medium case forecast; and (3) for a forecast of aluminum smelter and other direct service industry (DSI) demand.

The non-DSI forecasts generally rely on the forecasts from the Fourth Power Plan for their long-term demand trends. The decision to use the Fourth Power Plan forecast trends was based partly on an assessment of the accuracy of those forecasts over the five or six years since they were done.[2] The total demand forecasts tracked actual loads very closely between 1995 and 2000. The average percentage error in the forecast of electricity consumption for those years has been less than one half of a percent. Figure A-1 illustrates actual consumption compared to the medium, medium-low and medium-high forecasts through 2000. Figure A-1 also illustrates the ability of the model to simulate the period before 1995 when actual values of the main forecast drivers are used.

The forecasts for individual consuming sectors have also been quite accurate since the 1995 forecasts were done. The level of residential consumption was overforecast by an average of 0.6 percent. Commercial consumption was underforecast by an average of 0.9 percent, and industrial consumption, excluding DSIs, was overforecast by an average of 3.6 percent. Since there was little evidence that the long-term forecasts were departing seriously from actual electricity consumption, the Council decided to continue to rely on its earlier forecast trends for non-DSI electricity demand.

The medium case non-DSI forecast is developed in two stages. The first stage is a near-term monthly forecast of demand recovery from the recent energy crisis. The second stage is a long-term forecast of demand trends from 2005 to 2025.

[2] Northwest Power Planning Council. "Economic and Electricity Demand Analysis and Comparison of the Council's 1995 Forecast to Current Data." September 2001, Council Document 2001-23. http://www.nwcouncil.org/library/2001/2001-23.htm

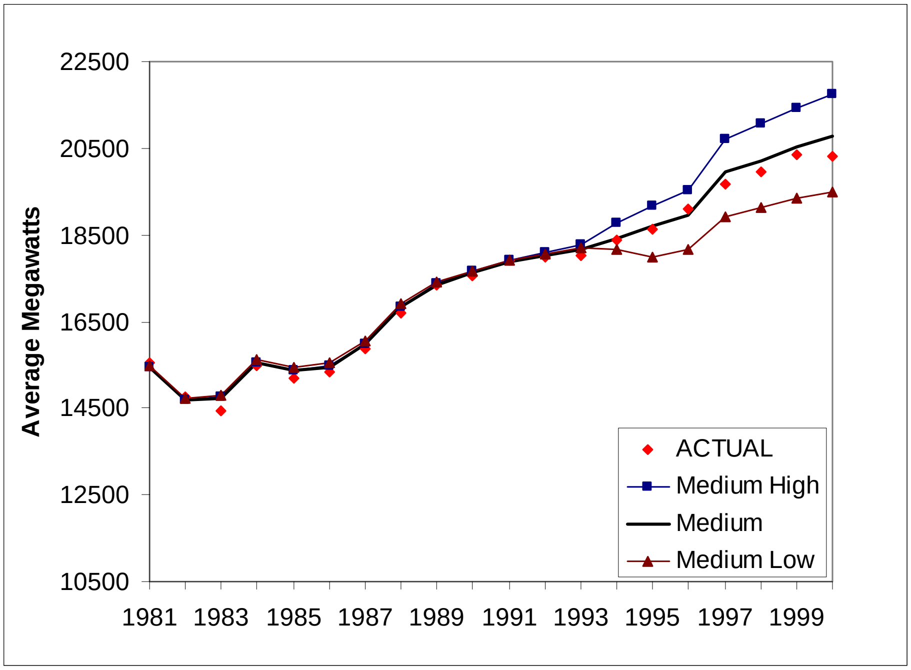



**Figure A-1: Demand Forecast Versus Actual Consumption of Electricity**

During late 2000 and 2001, electricity demand decreased dramatically in the region due to the electricity crisis, large increases in retail electricity rates, and an economic recession. The Council analyzed the components and causes of the 2000-2001 decline in electricity consumption in its assessment of the outlook for winter 2001-2002 electricity adequacy and reliability.[3] As illustrated in Figure A-2, nearly 60 percent of the reduction was due to closing down aluminum smelters, which make up the bulk of the DSI category. Therefore, a large part of the total medium forecast of demand recovery depends on specific assumptions about the return to operation of aluminum and other large industrial loads that were either bought out or shut down during 2001. The medium case forecast to 2005 addresses the recovery from this starting condition.

The medium case forecast of non-DSI demand recovery depends on assumptions about recovery from the economic recession and the effects of recent retail electricity price increases, although these effects are not modeled in any formal way. In general, the effects of higher retail electricity prices are assumed to dampen the effect of economic recovery on electricity use and slow the recovery of electricity demand. By 2005 non-DSI electricity demands are assumed to have nearly returned to a non-recession level, but that demand is lower than the Fourth Power Plan forecast due to some assumed permanent effects of higher electricity prices, as well as lasting efficiency improvements achieved during the crisis.

[3] Northwest Power Planning Council. "Analysis of Winter 2001-2002 Power Supply Adequacy." November 2001. Council Report 2001-28. http://www.nwcouncil.org/library/2001/2001-28.pdf

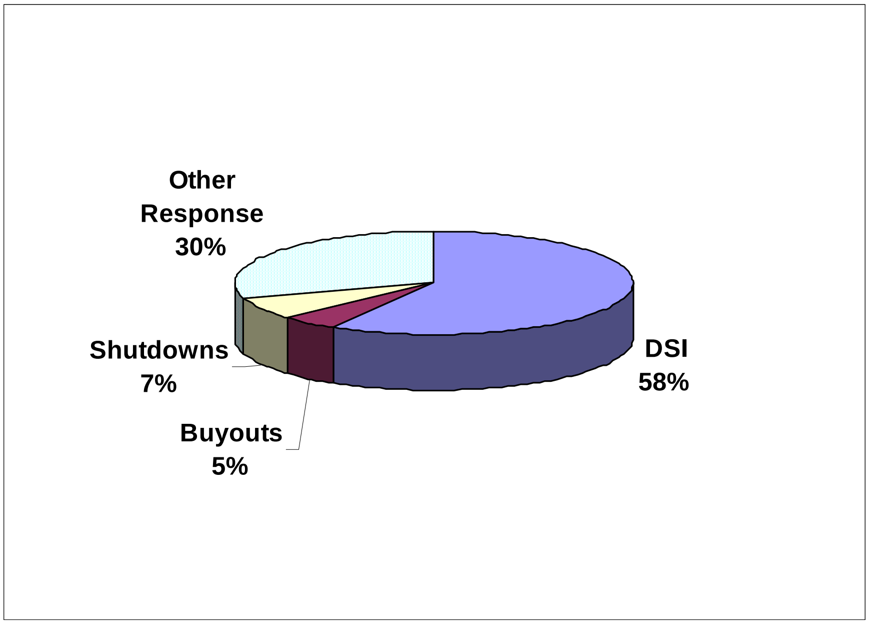



**Figure A-2: Components of a 20 Percent Load Reduction From July 2000 to July 2001**

The near-term medium forecasts are done on a monthly basis through 2005. The monthly forecasts through 2005 are done as electricity loads to facilitate tracking the forecast against actual load data as it becomes available. After 2005 the forecast is presented as electricity sales and is comparable to the range forecasts and to previous Council demand forecasts.

The range of long-term non-DSI forecasts is developed for the years following 2005. These four forecasts, as well as the medium case extension beyond 2005, depend on the growth rates of the corresponding forecasts in the Fourth Power Plan. The 2005 starting points for the range forecasts are estimated by applying Fourth Plan low to high case growth rates to an estimate of actual electricity demand in 2000 instead of the Fourth Plan forecasts for 2000. However, the relative pattern of growth for each case is adjusted to resemble the pattern of near-term medium case decreases in 2001 and recovery to 2005. After 2005, low to high case annual growth rates from the Fourth Plan were applied to the respective range of cases. This approach results in a narrower range of forecasts than the corresponding years' forecasts in the Fourth Power Plan.

The long-term forecasts should be viewed as estimates of future demand, unreduced for conservation savings beyond what would be induced by consumer responses to price changes. The Council has referred to these forecasts as "price effects" forecasts in the past. The shift from actual consumption to the price effects forecast is made in 2001. In the medium case, the only sector with any significant programmatic conservation by 2001 in the Fourth Power Plan was the residential sector. Residential sector consumption in 2001 has 191 average megawatts of programmatic conservation savings added to demand. This makes the decrease in residential consumption appear smaller in the forecast than actual consumption decreases are likely to be for 2001. Similar adjustments affect the higher growth cases for the other sectors as well.

The forecast of electricity demand by the region's aluminum smelters and the few other remaining industrial plants that were traditionally served directly by the Bonneville Power Administration (DSIs) are discussed separately. The forecast of aluminum smelter electricity use is an exception to reliance on the Fourth Plan forecast trends. Both the method of forecasting and the results are significantly different from the Fourth Power Plan.

## DEMAND FORECAST

The medium-term monthly forecasts are presented in the form of monthly "load" forecasts. That is, the values include transmission and distribution losses. The long-term forecasts are presented as electricity sales, or electricity consumption at the end-use level, and therefore exclude transmission and distribution losses. The long-term forecasts of electricity demand are developed for individual consuming sectors such as residential, commercial, and industrial. The long-term forecasts are directly comparable to the demand forecasts presented in the Fourth Power Plan. Detailed tables of annual electricity demand forecasts by sector appear at the end of this appendix.

The forecast of demand for electricity by aluminum smelters is treated separately from the non-DSI demand. This reflects the large amount of electricity required by these plants combined with a growing uncertainty about their future operation in the region.

## Non-DSI Forecasts

### Near-Term Monthly Non-DSI Load Forecast

Figures 3a and 3b illustrate how the near-term forecasts of non-DSI loads are designed to track recovery back toward the forecast trends from the Council's Fourth Power Plan. In Figure A-3a the upper line is the Fourth Power Plan trend forecast converted to electricity loads with a monthly pattern added. The lower line shows the near-term monthly forecast of loads. The dashed vertical line separates actual monthly load data from the forecast. The recovery may be clearer in the corresponding annual numbers shown in Figure A-3b.

When the Council first developed a near-term forecast of load recovery in October 2001, it was expected that non-DSI loads would recover to near the Fourth Plan forecast levels by 2004. This is no longer the case, as shown in Figures 3a and 3b. There are two substantial reasons for the changes to the near-term load forecast since the earlier assessment. First, the anticipated rate of economic recovery has been slower than expected. Second, energy prices, which fell substantially in 2002, have increased again in 2003. Some of the increase is due to temporary conditions including strikes in the oil industry of Venezuela, concerns about the war in Iraq, a cold winter in the Eastern part of the country, and low runoff forecasts for the Pacific Northwest. However, other contributors to high energy prices may be indicative of longer-term trends. These include the reduced growth in natural gas supplies in spite of significant drilling activity and continued high retail prices for Bonneville's customers and the customers of investor-owned utilities as well.

As shown in Figure A-3b, instead of recovering to the long-term trend forecast from the Fourth Power Plan by 2004, the revised annual non-DSI load forecast remains below the Fourth Plan forecast in 2005. This difference, which amounts to 929 average megawatts, is considered to be a permanent reduction in electricity demand, and affects the long-term forecast as well. The reductions are focused in the industrial sector, where energy intensive businesses are vulnerable to the large price increases the region has suffered since 2001.

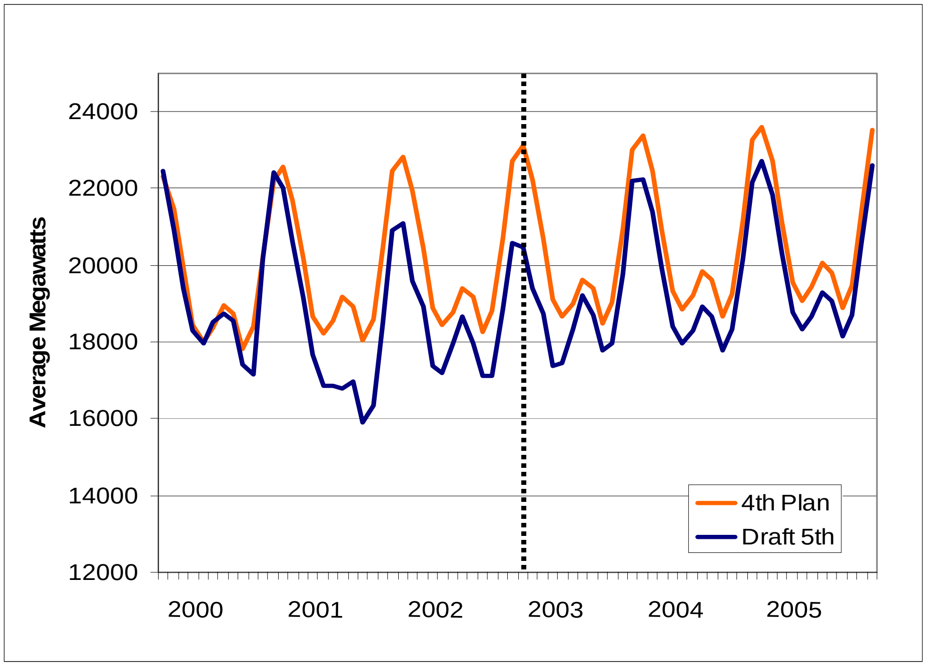



**Figure A-3a: Comparison of Monthly Near-Term Forecast to the Fourth Power Plan**

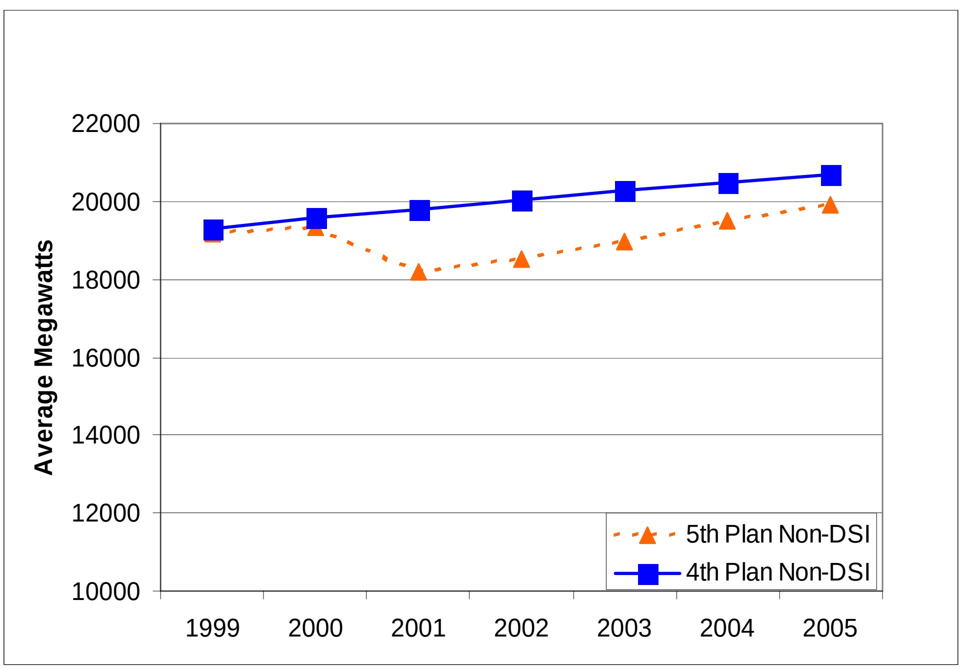



**Figure A-3b: Comparison of Annual Near-Term Forecast to the Fourth Power Plan**

### Long-Term Forecasts of Non-DSI Demand

The range of long-term forecasts of total non-DSI electricity sales is shown in Figure A-4. In the medium forecast, non-DSI electricity consumption grows from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025. This is an increase of 1.33 percent, and 275 average megawatts, per year from 2000 to 2025. These growth indicators are lowered somewhat by the electricity crisis and recession in 2000-01. From 2005 to 2025 the average annual growth rate is 1.43 percent per year, with an average annual increase in consumption of 300 average megawatts.

Figure A-4 illustrates how the Fourth Plan demand forecast and the near-term and long-term forecasts for the Fifth Power Plan compare. The near-term forecast reflects the currently depressed electricity demand and then merges into the medium forecast. The other forecasts in the range appear as dashed lines that extend from 2005 to 2025. The Fourth Plan forecasts appear as solid lines that extend to 2015. Historical actual weather adjusted sales appears as a dotted line through the year 2000.

The range of forecasts indicates that actual future demands should fall within plus or minus 15 percent of the medium forecast in 2025 with fairly high probability. This is reflected in the medium-low to medium-high forecast range in Table A-2. However, under more extreme variations in circumstances they could vary by 30 to 40 percent from the medium forecast, as shown by the low to high forecast range.

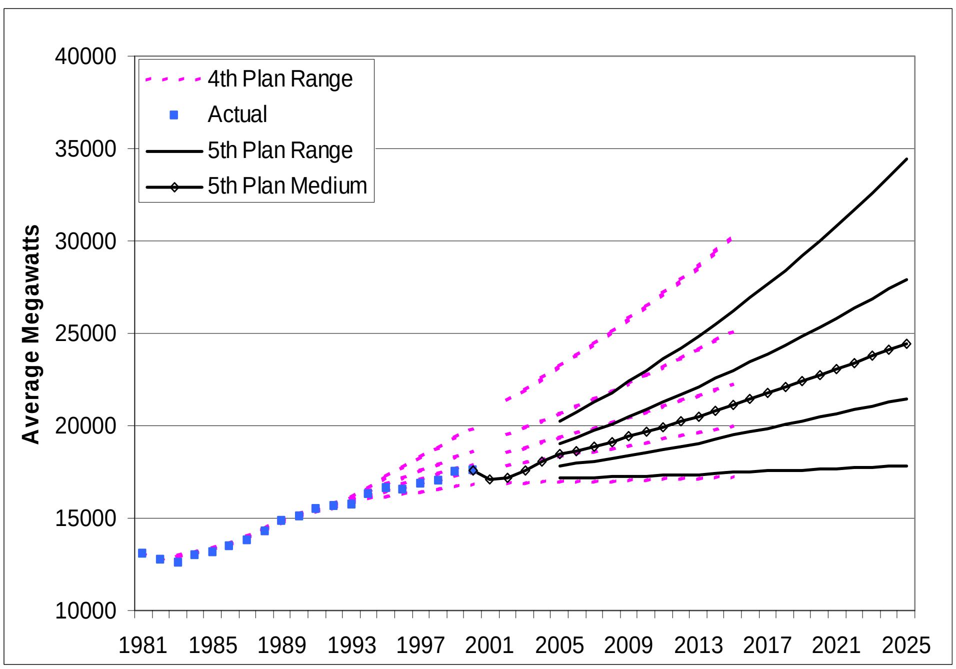



**Figure A-4: Forecast Total Non-DSI Electricity Sales Compared to Fourth Plan Forecasts**

**Table A-2: Non-DSI Electricity Sales Forecast Range**

| | | | | Growth Rates | |
|---|---|---|---|---|---|
| | 2000 | 2015 | 2025 | 2000-15 | 2000-25 |
| | (Actual) | | | | |
| **Low** | 17603 | 17489 | 17822 | -0.04% | 0.05% |
| **Medium Low** | 17603 | 19482 | 21474 | 0.68% | 0.80% |
| **Medium** | 17603 | 21147 | 24464 | 1.23% | 1.33% |
| **Medium High** | 17603 | 23000 | 27937 | 1.80% | 1.86% |
| **High** | 17603 | 26187 | 34397 | 2.68% | 2.72% |

Maintaining growth rates from the Fourth Power Plan's demand forecasts after 2005 implicitly assumes that the underlying assumptions remain about the same in terms of their effects on growth in electricity demand. The main driving assumptions in the Fourth Power Plan demand forecasts were economic growth, fuel price assumptions, and electricity price forecasts.

We have not attempted to develop a new economic forecast. However, the Fourth Plan's economic forecasts were checked for obvious deviations from actual values since the forecasts were developed in 1995.[4] The most aggregate determinates of demand are: population, households, and total non-farm employment. The number of households is the key driver of residential electricity demand growth. Actual household growth has followed the medium household forecast from the Fourth Power Plan. Population growth also tracked the medium forecast until 2000 Census data showed an upward revision in regional population. The new population count placed 2000 regional population between the medium and medium-high forecasts.

Employment forecasts are more sensitive to economic conditions than population and households. The period of sustained rapid growth in the national and regional economies during the late 1990s exceeded the Fourth Plan forecast assumptions, which were representative of longer-term sustained growth possibilities. Non-manufacturing employment, which drives the commercial sector forecasts has been closer to the medium-high forecast through 2000, although state forecasts of non-manufacturing employment that were available when the assessment was done show its growth moderating and moving back toward the medium forecast. The current slowdown in economic activity likely will have moved non-manufacturing employment back to the medium forecast or below.

The effects of robust economic growth in the late 1990s are even more apparent in manufacturing sector employment. Actual manufacturing employment moved well above the medium-high forecast in 1997 and 1998 when there was a boom in transportation equipment employment (i.e. Boeing). State forecasts available in mid-2001 expected manufacturing employment to return to medium forecast levels for 2001-2003. With the development of a recession in the fall of 2001 the manufacturing employment has probably fallen below medium forecast levels. There were some offsetting errors within the individual manufacturing sectors. In particular, electronic and other electrical equipment employment has been above the medium-high case, while paper and allied products has been below the medium-low.

[4] Council Document 2001-23, sited above.

Future natural gas prices are expected to be higher in this power plan than in the Fourth Plan. Table A-3 below compares 4th plan gas price forecasts for 2015 to this plan's natural gas price forecasts. The 2015 medium natural gas price forecast for this plan is above the high case in the Fourth Plan; a 54 percent increase. Based on the Council's Load Forecasting Models, this would imply that electricity demand might be increased by 3 to 4 percent over the Fourth Plan forecasts if nothing else changed.

**Table A-3: Natural Gas Price Forecasts for 2015 (2000 $ Per Million Btu)**

| | 4th Plan Forecast | 5th Plan Forecast |
|---|---|---|
| Low | $ 1.85 | $ 2.75 |
| Medium Low | $ 2.16 | $ 3.40 |
| Medium | $ 2.47 | $ 3.80 |
| Medium High | $ 3.09 | $ 4.30 |
| High | $ 3.71 | $ 4.90 |

However, the effects of higher gas prices may be offset by higher electricity prices. It is difficult to compare retail electricity prices between the two forecasts because the old price forecasting models are no longer appropriate for price forecasting in a partially restructured electricity market. The new price model addresses only wholesale electricity prices. Future retail prices will reflect both wholesale market prices and utility-owned resource costs if the system remains mixed, as it is currently. It is clear that higher natural gas prices will have an effect on electricity prices, both through the cost of utility owned natural gas-fired generation and through the wholesale market price of electricity. Higher electricity prices have a larger downward effect on electricity consumption than the upward effect that a comparable increase in natural gas prices would have. In the end, it isn't clear whether the changes in natural gas and electricity prices would cause a net increase or decrease in electricity consumption.

## Sector Forecasts

Total non-DSI consumption of electricity is forecast to grow from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025, an average yearly rate of growth of 1.33 percent. The year 2000 is used as the base year for the forecast and growth rate calculations. It is a more representative year for examining long-term trends in demand than 2001 or 2002 would be. Table A-4 shows the forecast for each consuming sector in the medium case. Each sector's forecast is discussed in separate sections below.

**Table A-4: Medium Case Non-DSI Consumption Forecast (Average Megawatts)**

| | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 | Growth Rates | | |
|---|---|---|---|---|---|---|---|---|---|
| | (Actual) | | | | | | 2000-25 | 2000-15 | 2005-25 |
| **Total Non-DSI Sales** | 17,603 | 18,433 | 19,688 | 21,147 | 22,742 | 24,464 | 1.33 | 1.23 | 1.43 |
| **Residential** | 6,724 | 7,262 | 7,687 | 8,230 | 8,809 | 9,430 | 1.36 | 1.36 | 1.31 |
| **Commercial** | 5,219 | 5,453 | 5,771 | 6,146 | 6,556 | 6,993 | 1.18 | 1.10 | 1.25 |
| **Non-DSI Industrial** | 4,836 | 4,904 | 5,397 | 5,919 | 6,505 | 7,150 | 1.58 | 1.36 | 1.90 |
| **Irrigation** | 652 | 629 | 641 | 654 | 667 | 681 | 0.17 | 0.02 | 0.40 |
| **Other** | 172 | 185 | 191 | 198 | 204 | 211 | 0.82 | 0.93 | 0.66 |

### Residential Sector

Residential electricity consumption is forecast to grow by 1.36 percent per year between 2000 and 2025. Figure A-5 illustrates the range of the residential consumption forecast, compared to historical data, and the forecasts from the Council's Fourth Power Plan. The medium case residential demand forecast for 2005 is 161 average megawatts lower than the Fourth Plan forecast for that year. The forecast growth of residential sector use of electricity is slightly less than the growth from 1986-1999 of 1.8 percent annually.

The medium residential forecast remains just below the Fourth Plan medium case. This adjustment reflects the fact that the Fourth Plan slightly over forecast actual residential sales between 1995 and 2000, and that there are expected to be some longer-term effects of utility and consumer efficiency investments in response to the electricity crisis and high prices of the last couple of years. The 2005 residential demand forecast is 161 megawatts lower than the Fourth Plan forecast for 2005, or a 2.2 percent reduction in the forecast consumption level.

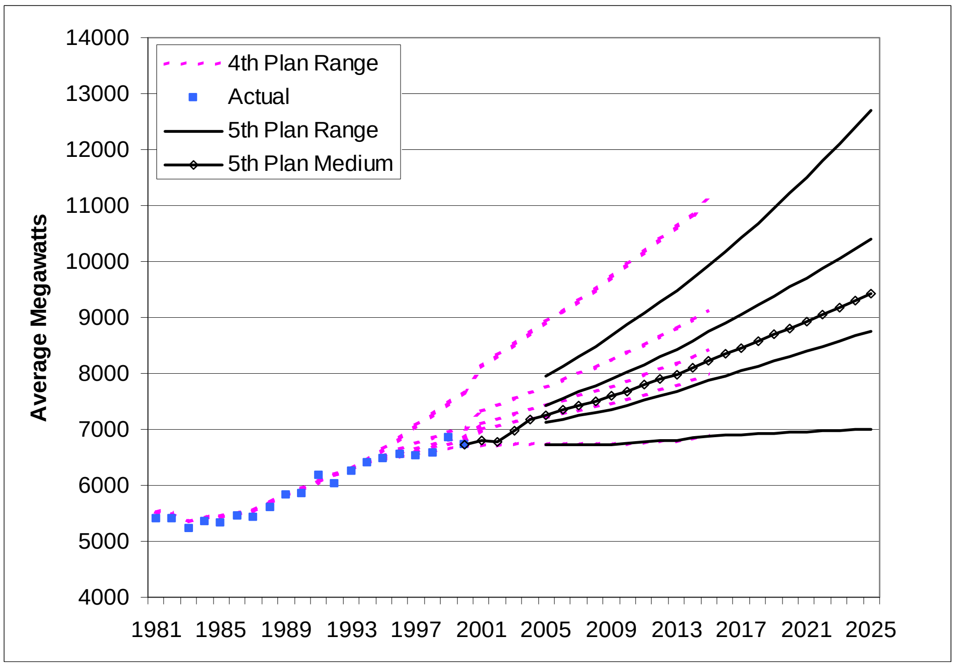



**Figure A-5: Forecast Residential Electricity Sales Compared to Fourth Plan Forecasts**

Although the near-term forecast shows a significant dip in residential consumption in 2001, the reduction in consumption is dampened significantly by making the adjustment to a "price effects" forecast in 2001. That is, the forecasts are intended to reflect what demand for electricity would be if new conservation programs are not implemented. The consumption levels before 2001 include the effects of conservation programs on electricity use, thus reducing consumption. The residential sector sales forecast is the only one affected by programmatic conservation in 2001 in the medium case of the Fourth Power Plan. The adjustment to eliminate the savings from conservation programs increased the residential electricity use forecast by 191 average megawatts in 2005.

It should be noted that the forecasts presented here have not been adjusted for the future effects of new building or appliance codes that have been put into effect since the Fourth Plan forecasts were done. These changes in minimum energy efficiency would reduce the future "price effects" forecast shown here. The analysis to make these adjustments has not been completed at this time.

## Commercial Sector

Commercial sector electricity consumption is forecast to grow by 1.18 percent per year between 2000 and 2025, increasing from 5,219 to 6,993 average megawatts. Figure A-6 illustrates the forecast. Compared to the Fourth Power Plan forecast of commercial electricity use, the medium case has been adjusted upwards to reflect the fact that there has been a slight tendency to under forecast commercial demand since 1995. The forecast for 2005 is 325 average megawatts higher than the 2005 medium forecast in the Council's Fourth Power Plan.

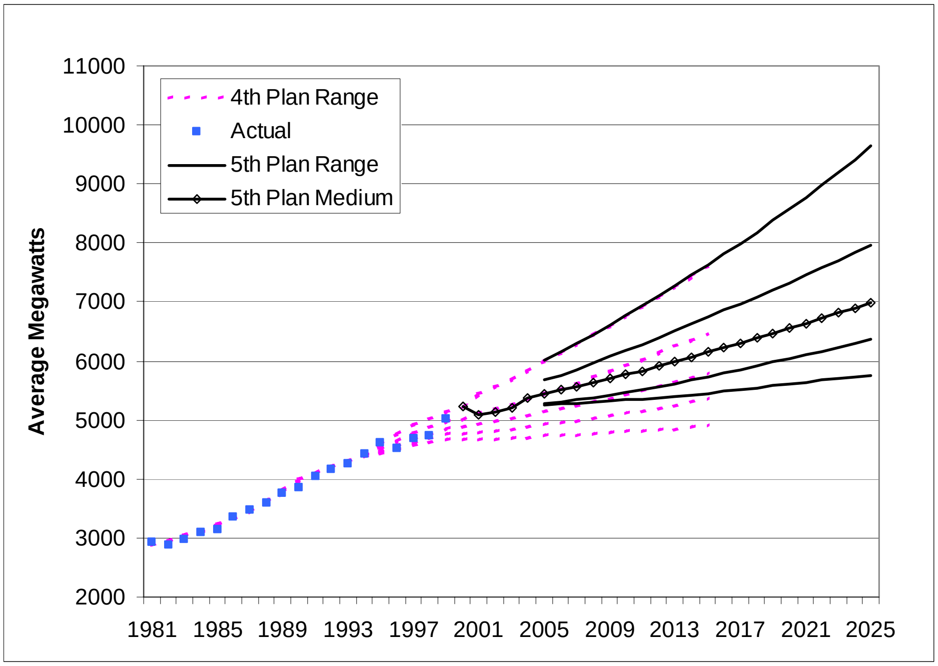



**Figure A-6: Forecast Commercial Electricity Sales Compared to 4th Plan Forecasts**

Comments in the residential section about the effects of new building and appliance efficiency codes apply to the commercial sector as well. In the medium commercial sector forecast, there is no adjustment made for conservation programs in shifting to the medium price effects forecast in 2001. The conservation program adjustment does affect the starting point for the medium-high and high forecast in 2005. It also affects the 4th plan forecast shown in the graph. The transition from a "sales" forecast to a "price effects" forecast is apparent in the high case, the upper line in Figure A-6. The near-term forecast dip in the medium case is the expected effect of recent price changes and economic recession.

The growth forecast for the commercial sector is for a significantly slower growth than in the past. Between 1986 and 1999 commercial electricity use grew at 3.1 percent per year.

Therefore, the forecast growth rate of 1.2 percent represents a big slowdown in commercial growth. This slowdown was present in the 4th power plan forecasts as well. But there has not been a significant under forecasting trend since the Fourth Plan forecast of commercial demand was done even though the region has experienced a robust growth cycle during these years. Figure A-7 shows the forecast compared to actual sales for 1994 through 1999. Although actual sales for 1995 and 1999 are above and at the medium-high, respectively, the other four years are at or below the medium case forecast.

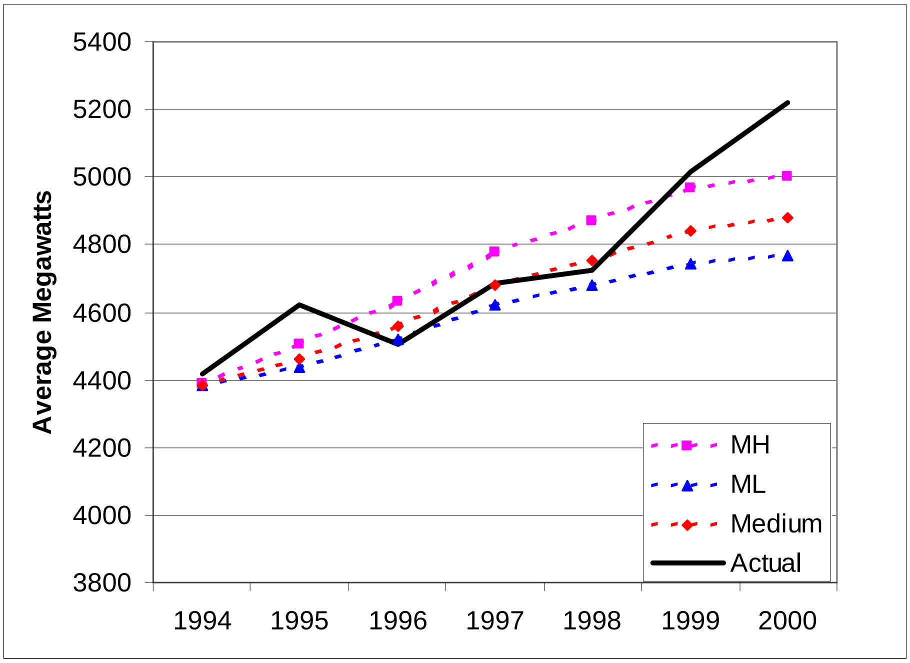



**Figure A-7: Fourth Plan Commercial Forecast Performance**

Several factors could help explain the forecast of slower growth of commercial electricity use. The underlying forecast of employment growth in the non-manufacturing sectors is significantly slower than historical growth. This alone could account for much of the decreased electricity demand growth forecast. In addition, the demand forecasting model accounts for building vintages and efficiency. As newer, more energy efficient, buildings that have been subject to building efficiency codes enter the stock and replace older buildings the electricity use per square foot of buildings will tend to decrease. Such factors may account for the decreased rate of growth of commercial electricity use, but the Council continues to evaluate the commercial forecasts to see if these forecasts might understate future commercial electricity needs. The Council would like to hear the views of utilities and the public on this issue.

### Non-DSI Industrial Sector

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Further, the use tends to be concentrated in a relatively few very large users instead of spread among many relatively uniform users.

The direct service industries (DSIs) of Bonneville are treated separately in this discussion because this hand-full of plants (mainly aluminum smelters) accounts for nearly 40 percent of industrial electricity use. In addition, the future of these plants is highly uncertain. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors are declining or experiencing slower growth. These traditional resource based industries are becoming less important to the regional electricity demand while new industries, such as semiconductor manufacturing are growing faster.

Non-DSI industrial consumption is forecast to grow at 1.58 percent annually from 2000 to 2025 (see Figure A-8). Electricity consumption grows from 4,836 average megawatts in 2000 to 7,150 in 2025. The medium-high and medium-low forecasts are about 20 and 30 percent higher and lower than the medium forecast, respectively. This reflects the greater uncertainty in forecasting the industrial sector's electricity demand. In addition, the actual industrial consumption data is becoming more difficult to obtain as some consumers gain access to electricity supplies from independent marketers instead of their local distribution utility who must report their electricity sales.

The near-term forecast reflects a severe reduction of consumption in 2001 and 2002. Higher electricity prices are expected to continue to repress industrial electricity use. 2005 demand remains significantly, 1,022 average megawatts; lower than the 2005 forecast for Fourth power plan.

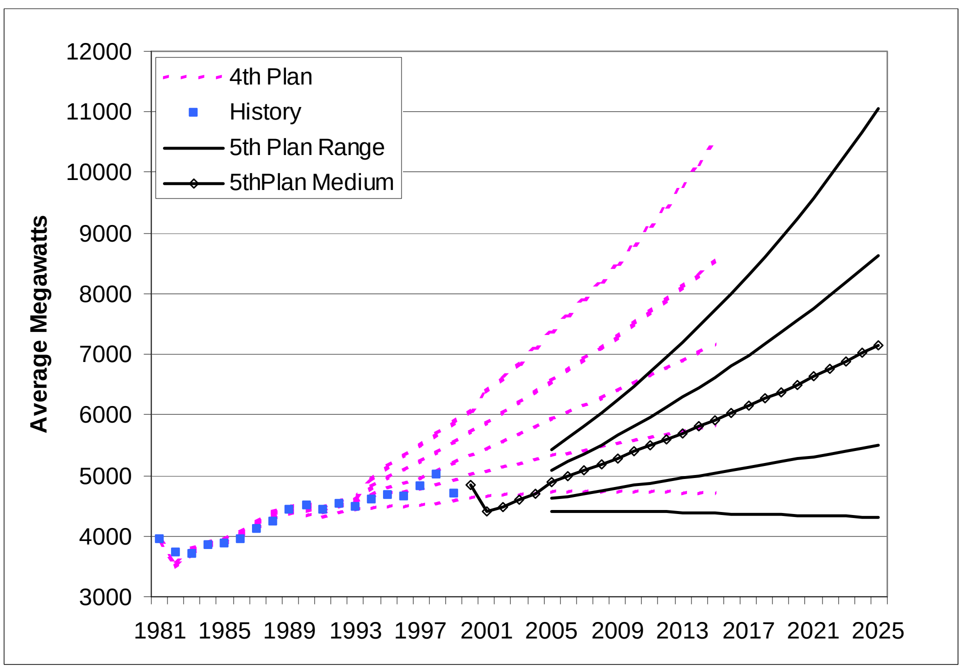



**Figure A-8: Forecast Non-DSI Industrial Electricity Sales Compared to Fourth Plan Forecasts**

## Irrigation and Other Uses

Irrigation and other uses are relatively small compared to the residential, commercial and industrial sectors. Irrigation has averaged about 640 average megawatts between 1986 and 1999 with little trend discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. Other includes streetlights and various federal agencies that are served by Bonneville. It is relatively stable and averaged about 180 megawatts a year between 1986 and 1999.

Unlike most other sectors in the forecast, the irrigation forecast range has been changed substantially, although due to its small size it has little effect on total demand. Analysis showed that the average irrigation use over the past 20 years was substantially lower than where the medium forecast in the Fourth Plan started. The 2005 consumption was lowered to 629 average megawatts, compared to a Fourth Plan value of 700 average megawatts in that year. The forecast medium case, shown in Figure A-9, includes very little growth, as has been the case for the last 10 or more years. The range considers a high case growth of 0.7 percent a year and the low case considers that irrigation electricity use could decline by 0.8 percent annually. Substantial expansion of irrigated agriculture seems unlikely given the competing uses of the oversubscribed water in the Pacific Northwest.

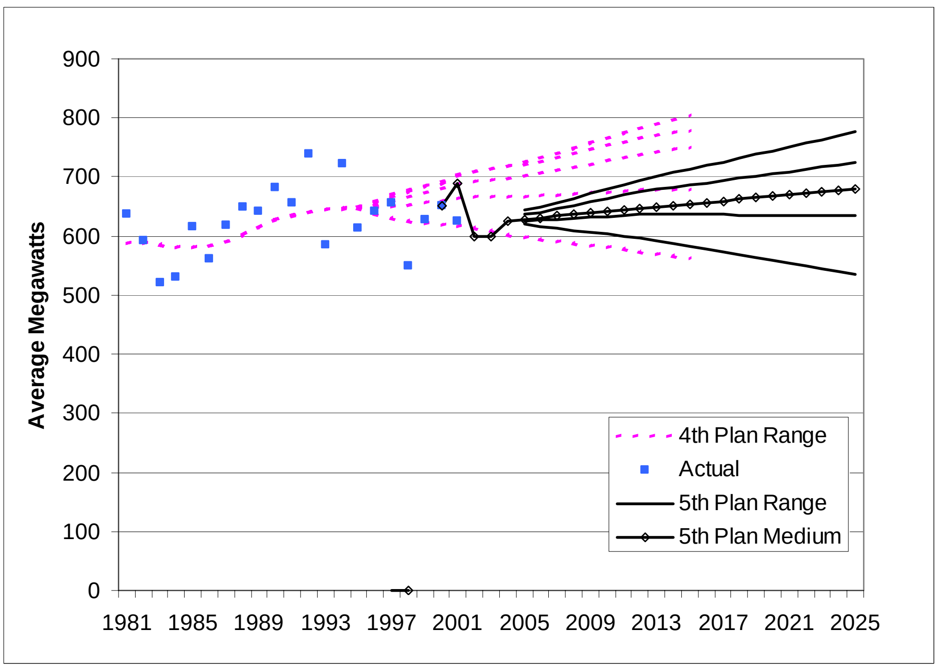



**Figure A-9: Forecast Irrigation Electricity Sales Compared to Fourth Plan Forecasts**

Other electricity use did not have a range associated with its forecast in the Fourth Power Plan. The other forecast is unchanged from the Fourth Plan forecast, growing at just under one percent annually.

# Aluminum (DSIs)

## Background

Direct Service Industries, or DSIs, refers to a group of industrial plants that have purchased electricity supplies directly from the Bonneville Power Administration. In the past, most of these plants obtained all of their electricity needs from Bonneville. Recently, many of these plants have diversified their electricity supplies, either by choice or because of reduced allocations from Bonneville. This discussion generally addresses the total electricity requirements of these industrial consumers regardless of source.

“DSIs” is often used interchangeably with aluminum smelters because aluminum smelters account for the vast bulk of this categories’ electricity consumption. When all of the region’s ten aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. Table A-5 shows the smelters, their locations, their aluminum production capacity and the amount of electricity they were capable of consuming at full operation.

**Table A-5: Pacific Northwest Aluminum Plants**

| Owner | Plants | County | Capacity | Electricity Demand |
|---|---|---|---|---|
| | | | (M tons/yr.) | (MW) |
| Alcoa | Bellingham WA | Whatcom | 282 | 457 |
| Alcoa | Troutdale OR | Multnomah | 130 | 279 |
| Alcoa | Wenatchee WA | Chelan | 229 | 428 |
| Glencore | Vacouver WA | Clark | 119 | 228 |
| Glencore | Columbia Falls MT | Flathead | 163 | 324 |
| Longview Aluminum | Longview WA | Cowlitz | 210 | 417 |
| Kaiser | Mead WA | Spokane | 209 | 390 |
| Kaiser | Tacoma WA | Pierce | 71 | 140 |
| Golden Northwest | Goldendale WA | Klickitat | 166 | 317 |
| Golden Northwest | The Dalles OR | Wasco | 84 | 167 |
| | | | | |
| Total | | | 1663 | 3145 |

Source: Metal Strategies, LLC, *The Survivability of the Pacific Northwest Aluminum Smelters*, Redacted Version, February, 2001.

This amount of electricity is significant in the Pacific Northwest power system. The amount of power used by these aluminum plants in full operation could account for 15 percent of total regional electricity use. When operating, the electricity use of these plants tends to be very uniform over the hours of the day and night. However, the aluminum plants have faced increasing difficulty operating consistently over the past 20 years because of increased electricity prices and aluminum market volatility.

Aluminum smelting in the region started during the early 1940s to help build up for the war effort and to provide a market for the hydroelectric power production in the region. Smelting capacity was expanded throughout the 1960s and 1970s. Since then no new plants have been added, although improvements to the existing plants have resulted in some increases in smelting capacity. The 10 aluminum plants in the Pacific Northwest accounted for a significant share of the U.S., and even the world, aluminum smelting capacity. Before the millennium, the region's smelters accounted for 40 percent of the U.S. aluminum smelting capacity and about 6 to 7 percent of the world capacity. Their presence in the region is largely due to the historical availability of low priced electricity from the Federal Columbia River Power System. Aluminum smelting is extremely electricity intensive. Electricity accounts for about 20 percent of the total cost of producing aluminum worldwide and is therefore a critical factor in a plant's ability to compete in world aluminum markets. With increasing electricity prices this share is now substantially larger for the region's smelters, perhaps as much as one-third of costs.

### Deteriorating Position of Northwest Smelters

The position of the region's aluminum smelters in the world market has been deteriorating since 1980. This is due to a combination of increased electricity prices, declining world aluminum prices and the addition of lower cost aluminum smelting capacity throughout the world.

Around 1980 the cost and availability of electricity supplies to the Pacific Northwest aluminum plants began to change dramatically. At the time, Bonneville supplied all of the smelters' electricity needs at very competitive prices. However, between 1979 and 1984 Bonneville's electricity prices increased nearly 500 percent. This is illustrated in Figure A-10, which shows Bonneville preference utility rates for electricity since 1940. The aluminum plants, along with other electricity consumers in the region, suddenly found themselves in a much less advantageous position with regard to electricity costs.

As the region's aging smelters have struggled to stay competitive in a world aluminum market, the conditions of their electricity service have also been changing. During the 1970s, the region's electricity demand began to outgrow the capability of the hydroelectric system. The fact that aluminum smelters had no preference access to the Federal hydroelectric energy meant that their electricity supplies were threatened. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 (The Act) extended the DSI access to Federal power in exchange for the DSIs covering, for a time, the cost of the residential and small farm exchange for investor-owned utility customers. In addition, the DSIs were to provide a portion of Bonneville's reserve requirements through interruptibility provisions in their electricity service.

Over the years since the Act, the DSI service conditions and rates have changed in response to changing conditions. After the dramatic electricity price increases of 1980, smelters became more vulnerable to changing aluminum market conditions. Between 1986 and 1996 Bonneville implemented electricity rates for the aluminum plants that changed with changes in aluminum prices. These rates were intended to help the aluminum plants operate through difficult aluminum market conditions, and to help stabilize Bonneville's revenues. Until 1996, aluminum plants in the region bought all of their electricity from Bonneville, with the exception of one plant that acquired part of its electricity supply from a Mid-Columbia dam. In the 1996 rate case, aluminum plants chose to reduce the amount of energy they purchased from Bonneville to about 60 percent of their demand in order to gain greater access to a (then) very attractive wholesale power market. In the 2001 rate case, Bonneville further reduced the aluminum allocation to about 45 percent of smelters' potential demand, or about 1,425 megawatts. The aluminum smelters are now required to obtain over half of their electricity requirements in the wholesale electricity market or from other non-Bonneville sources.

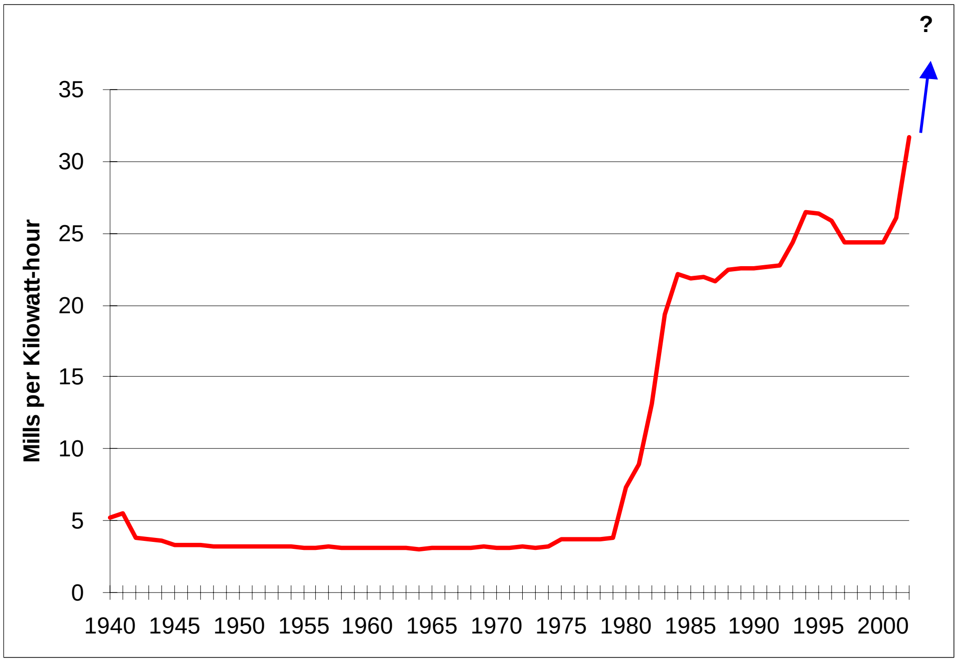
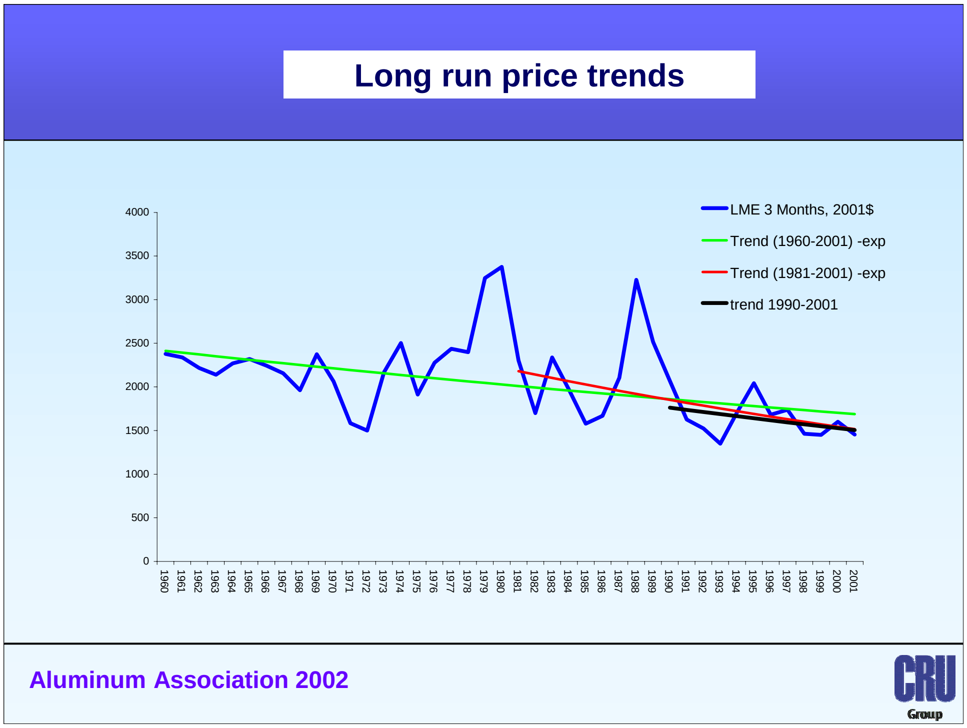



**Figure A-10: Bonneville Power Administration Preference Rates**

Most new world aluminum smelting capacity has been added outside of the traditional Western economies, often in countries where social agendas may be driving the capacity decisions as much as aluminum market fundamentals. The disintegration of the former Soviet Union and the liberalization of trade in China have had a significant effect on the development of a world aluminum market. The addition of more capacity over time and improving aluminum smelting technology is reflected in declining aluminum price trends. Figure A-11 shows aluminum prices from 1960 through 2001. Trends calculated over different time periods all show a consistent downward trend. On average, aluminum prices corrected for general inflation decreased by about 0.8 percent annually from 1960 to 2001. The downward trend is particularly pronounced from 1980 to the present.

The steady improvement in aluminum smelting technologies over time has meant that the region's smelters have tended to grow relatively less competitive in terms of their operating costs as new more efficient capacity has been added throughout the world. By investing in improved technology some of the region's smelters have been able to partially offset the effects of these declining cost trends. In addition, the worsening position of the region's aluminum smelters relative to other aluminum plants may have been partly offset by the decreasing capital costs and debt as older plants and equipment depreciate. Nevertheless, a growing share of the regional smelting capacity has become swing capacity. That is, plants could operate profitably during times of strong aluminum prices or low electricity prices, but tended to shut down during periods of less favorable market conditions.




Source: CRU International Ltd., Presentation to Aluminum Association 2002.

**Figure A-11: Aluminum Price Trends**

Caught in the pincers of decreasing aluminum prices and increasing electricity prices, many of the region's smelters have reached a critical point. Events since the spring of 2000, in both the electricity and aluminum markets, have had a dramatic effect on the region's aluminum plants. By mid-summer of 2001, all of the region's aluminum smelters had been shut down for normal production, either because of high electricity prices and poor aluminum market conditions or because Bonneville bought back the electricity to help meet an expected shortfall of electricity supplies and remarket the electricity at much higher market prices. The elimination of aluminum electricity load played a key role in avoiding electricity shortages in the summer of 2001 and the following winter.

Sharing of the savings from remarketing aluminum plants' electricity helped ease the financial strain on aluminum companies and their employees of a long shut down. During 2002 electricity prices in the wholesale market fell to low levels, but aluminum prices remained very low and only a few smelters found it desirable to partially return to production. In addition, Bonneville's rates have remained high. There does not appear to be much optimism for a quick recovery of aluminum prices. Some analysts expect the global aluminum market to remain in surplus until 2005.

Currently, three of the region's smelters have closed permanently, another is in bankruptcy proceedings and appears likely to close permanently, and others are in dire financial straits. During 2003 aluminum plants only consumed 423 average megawatts of electricity. Three plants that had partially reopened have cut back or suspended operations.

With aluminum market recovery uncertain, and with expected future electricity prices too high for most aluminum plants to operate profitably, future aluminum electricity use is expected to be much lower than in previous Council plans. The ability of aluminum plants to operate depends critically on the level of electricity prices. With the medium natural gas price assumptions, the Council currently forecasts long-term spot market electricity prices to be in the $30 to $40 per megawatt-hour range in year 2000 dollars (see Figure A-12). Few, if any, of the region's smelters would be able to operate with electricity prices at that level. It is unclear how much of the aluminum load Bonneville might serve in the future, but Bonneville's future electricity prices may also be higher than aluminum plants can afford except when aluminum prices are especially high.

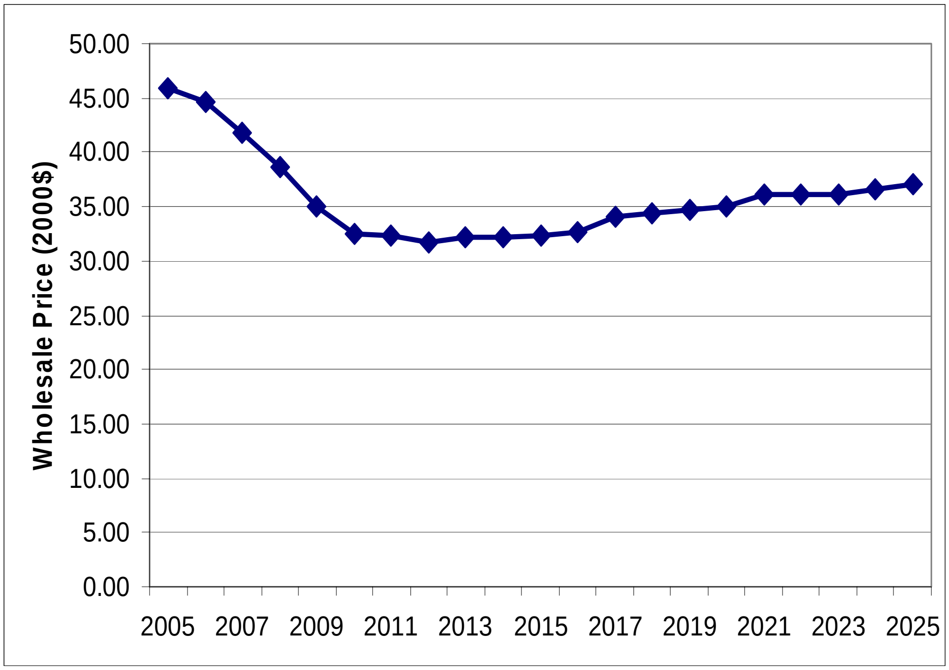



**Figure A-12: Medium Case Wholesale Price Forecasts for Mid-Columbia Electricity**

## A Simple Model of Aluminum Electricity Demand

A simple model of Pacific Northwest aluminum plants was developed to relate the likelihood of existing aluminum plants operating to different levels of aluminum prices and electricity prices. Given an aluminum price, the model estimates what each aluminum plant in the Northwest could afford to pay for electricity given its other costs. Then, for a given electricity price, the electricity demand of the plants that can afford to operate make up the aluminum electricity demand in the region. Basic data for the model came from the July 2000 study cited as the source for Table A-5, advice from the Council's Demand Forecasting Advisory Committee, and comments on a draft aluminum forecast paper.[5]

[5] "Forecasting Electricity Demand of the Region's Aluminum Plants." Northwest Power Planning Council document 2002-20. December, 2002.

Figure A-13 illustrates the relative competitiveness of the seven remaining Northwest aluminum plants as represented in the model. (It is assumed that the other three smelters in Troutdale, Oregon, Longview, Washington, and Tacoma, Washington are permanently closed.) Figure A-13 shows the amount that each plant could afford to pay for electricity given an assumed aluminum price of $1,500 per ton[6] (about 67 cents a pound), which is about the average aluminum price over the past several years.

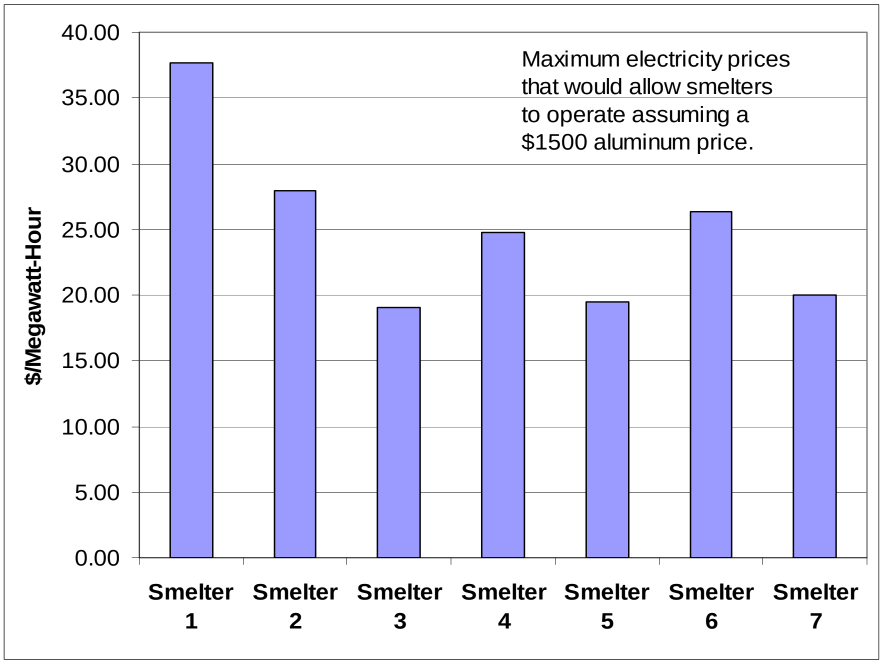



**Figure A-13: Affordable Electricity Price Limits of PNW Aluminum Smelters At $1,500 Per Ton Aluminum Prices**

One aluminum plant in the region is very efficient and is likely to operate under a wide range of electricity and aluminum prices. Three other smelters could pay around $25 a megawatt-hour for electricity if aluminum prices were $1,500 a tonne, which is higher than aluminum prices have averaged since 2000. The other smelters could only afford to operate at electricity prices near $20 per megawatt-hour.

There are some important limitations to this simple model. It is intended to represent whether aluminum plants would be willing to operate for an intermediate time period. The costs used in the model include an amount above the pure short-term operating costs to allow sufficient ongoing capital investments to maintain the plant's capability to produce. But the costs do not include sufficient returns on capital to justify the long-term operation of the plant.

Thus, the model does not address the question of when a plant would be likely to close permanently. In order to remain in operation, a plant would have to be able to recover sufficient funds during periods of high aluminum prices and low electricity prices to recover an adequate return on investment. However, as plants depreciate, or as they are sold at discounted prices, capital recovery becomes a smaller part of the decision, and strategic positioning in global

[6] "Tonne" refers to a metric ton, which contains 2,240 pounds.

markets may enable some plants to remain available for operation when conditions are attractive enough. The implicit assumption in the model is that if a plant can operate for the intermediate term under expected electricity and aluminum prices, then it will be able to recover sufficient returns during favorable cyclical market conditions to survive in the long term.

The model does not address the dynamics of temporary closures of aluminum plants or their return to operation. The dynamics of aluminum smelter operations are important considerations for assessing their potential value as demand-side reserves. The potential demand-side reserves that might be provided by aluminum plants include: very short-duration interruptions for system stability purposes; interruptions of up to four hours during extreme peak electricity price spikes; and long-term shut downs of several months to a year or more to address periods of poor hydroelectric conditions or other periods of significant generation capacity shortages. These issues will be addressed outside of the simple aluminum model described here. In the Council's portfolio risk model, aluminum plant closure, reserves, and reopening conditions are related to uncertain variations in electricity and aluminum prices. This will be discussed in more detail later.

### Model Results

By varying the aluminum and electricity prices over a range of possible values, the simple model can be used to simulate expected aluminum electricity demands under varying conditions. Aluminum prices were varied between $1,050 and $2,250 per tonne in $100 increments. For each aluminum price, electricity prices were varied between $20 and $40 per megawatt-hour. This generated 91 different estimates of aluminum plant electricity demand under the varying aluminum and electricity combinations. Figure A-14 shows the results of this exercise.

A couple of bracketing points are evident. First, at aluminum prices below $1,150 per tonne, none of the Northwest aluminum plants can operate profitably at any electricity price between $20 and $40 per megawatt-hour. Aluminum prices have seldom been below $1,200 a ton (in 2002 prices) in the past 20 years. On the other extreme, all seven smelters could operate at aluminum prices above $2,050 per tonne for electricity prices up to $40 per megawatt-hour.

If past trends in aluminum prices continue, aluminum prices might decline at about one percent a year. That would mean that average aluminum prices might average less than $1,500 over the next 20 years. Of course, there will be considerable volatility around that trend. At this point in the Council's planning process, we do not have a range of future electricity prices that match the range of natural gas prices we are assuming for our analysis. Preliminary analysis with the medium natural gas price forecast shows that wholesale electricity prices under medium assumptions (see Figure A-12) could be between $35 and $40 per megawatt-hour over the long term. In those ranges of electricity and aluminum prices, it is unlikely that more than two aluminum plants could operate, and electricity demand by aluminum smelters in the region would be less than 900 megawatts.

The results in Figure A-14 include an assumption that one smelter will continue to have access to low cost mid-Columbia dam power for part of its electricity demand. Access to some lower cost supplies of electricity from Bonneville or other sources and further investments in smelter efficiency may improve the ability of some smelters to stay in operation. The simple aluminum model was used to see what effect an offer of 100 megawatts of electricity priced at $28 per megawatt-hour would have on smelter operations. Assuming an availability of such electricity supplies changes the model results for the 91 combinations of aluminum and electricity prices.

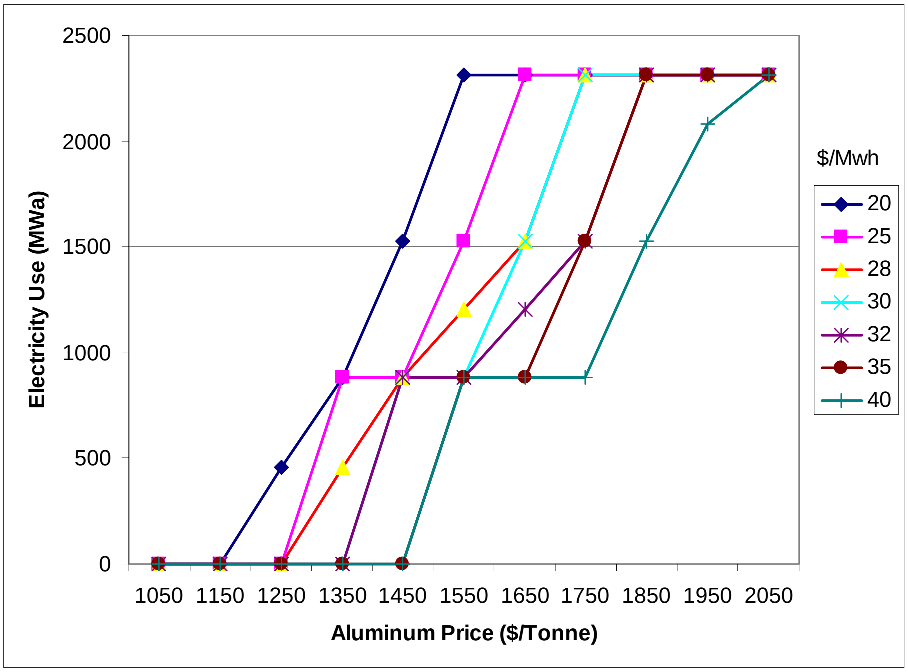



**Figure A-14: Spectrum of Potential Aluminum Smelter Electricity Demands**

In order to more easily illustrate these effects, an expected value of electricity demand was calculated for each assumed electricity market price. This was done by weighting electricity demand simulated at different aluminum prices by the percent of days in the last ten years that actual aluminum prices fell into that range. These expected electricity demands are shown in Figure A-15. Another way of characterizing an individual bar in Figure A-15 is that it is a weighted average of the electricity use in an individual line from Figure A-14.

Using just market electricity prices and the one mid-Columbia supply contract, expected smelter electricity demands ranged from 783 megawatts at $40 per megawatt-hour electricity prices to 2,138 megawatts at $20 electricity prices. This is shown in the left-most bar for each electricity price group in Figure A-15.

If smelters could arrange to purchase 100 megawatts of power priced at $28 per megawatt-hour, it is estimated to have a relatively small effect on expected aluminum operations (see the middle bars in Figure A-15). At market prices below $28 the expected electricity demand of aluminum smelters is actually reduced by the higher priced power supply. If market power prices were $40, the availability of 100 MW of power at $28 per megawatt-hour is estimated to increase the expected value of aluminum smelters' electricity demand of from 783 to 875 megawatts, a relatively small effect. If smelters could arrange a block of power at $20 (illustrated by the right-most bars in Figure A-15) the estimated increase in electricity demand at the $40 market price would be 314 megawatts. That increase is roughly the electricity demand of one additional smelter.

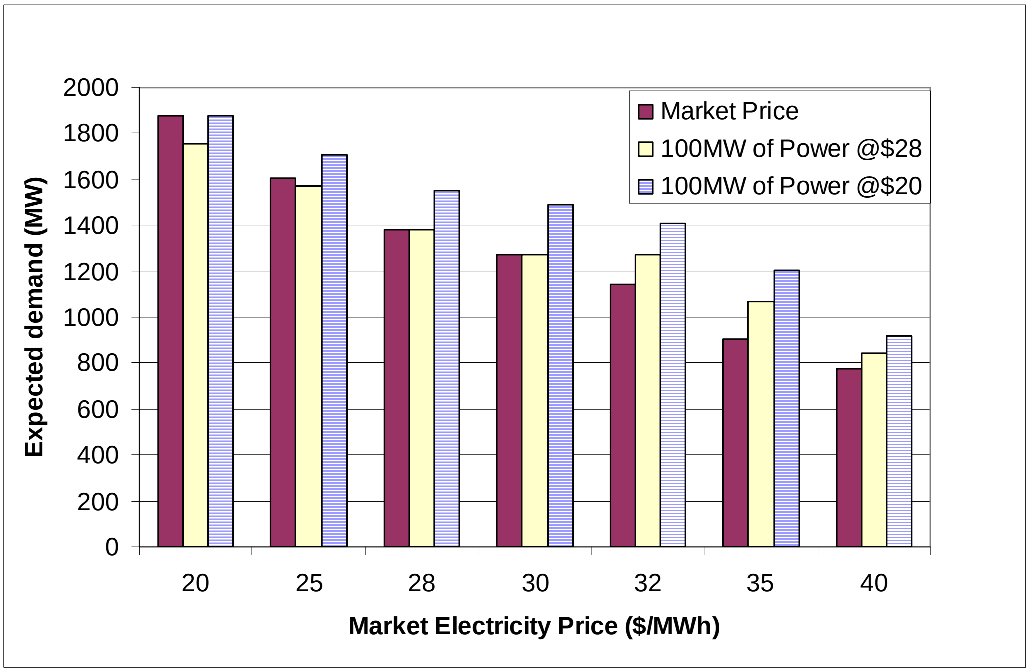



**Figure A-15: Expected Aluminum Plant Electricity Demand (Effect of Special Electricity Supplies)**

The analysis above addresses the question of whether the existing smelters in the region are likely to operate under different aluminum and electricity market conditions. It does not address the likelihood of permanent closure. Historically, older and less efficient smelters are not frequently closed permanently. Their depreciated capital costs allow them to operate when electricity and aluminum prices are attractive. They may provide an inexpensive option for aluminum supplies in tight aluminum markets. In addition, permanent closure may involve expensive site clean up.

The result is that the region might retain a large, but uncertain, electricity demand. If such a demand is required to be served when they need electricity, it can be very costly for their electricity supplier to maintain generating capacity to serve the potential demand. If serving the demand is optional, however, through either interruption agreements or the smelters purchasing available power in the market, it can have attractive features that may reduce electricity price volatility. The future of aluminum operations in the region may depend on the ability of aluminum plants to find, and get value for, their potential for complementing the power system in a competitive wholesale market.

## Mid-Term Aluminum Demand Assumption

The Council is required to include in its power plans a 20-year forecast of demand. The Council is also increasing its focus on the nearer term for purposes of reliability and adequacy analysis. For these purposes, a specific forecast of total electricity demand is useful. And for that, specific assumptions about DSI demands are needed. This section presents such a best guess forecast, but it is important to keep the extreme uncertainty regarding this assumption in mind when evaluating reliability, adequacy, or long-term resource strategies.

Figure A-16 shows the assumed mid-term pattern of aluminum electricity demand through 2005 compared to the Council's assumption for the Fourth Power Plan. In the current forecast, electricity demand is assumed to recover to about 1,000 megawatts by 2005. This would be consistent with two aluminum smelters operating plus 60 average megawatts of non-aluminum DSI demand. If the aluminum model is reasonably accurate, and if electricity can be acquired for $30 to $35 per megawatt-hour, this implies that aluminum prices would have to recover to $1,450 to $1,550 per tonne by 2005. The higher end of that range is similar to average aluminum prices during the past 10 years. Although aluminum prices have risen to above $1,600 in the first four months of 2004, given recent trends and events in world aluminum markets, the range of $1,450 to $1,550 per tonne should be viewed as a reasonably optimistic assumption for future aluminum prices.

The forecast is significantly more pessimistic about aluminum plants' ability to operate than the Council's Fourth Power Plan. This is consistent with a prolonged period of low aluminum prices during 2001 through 2004, with higher forecasts of electricity prices. It also is more pessimistic about the ability of some smelters to survive a prolonged period of high electricity prices, poor aluminum prices, and uncertainty about electricity markets and contracts.

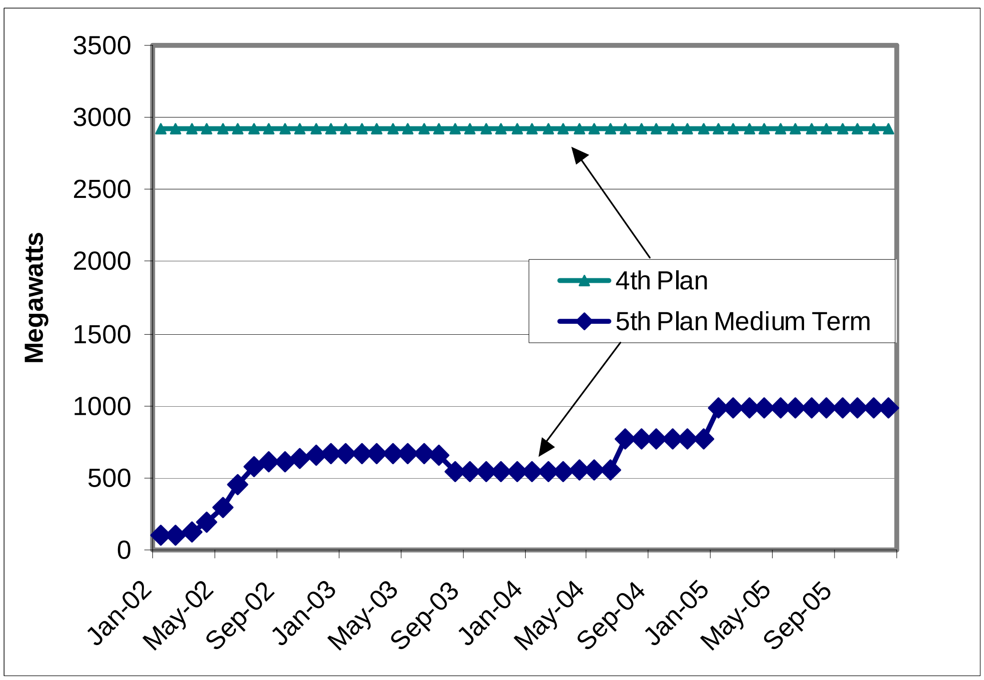



**Figure A-16: Medium Case Assumptions for Aluminum Demand Recovery to 2005 (Comparison to 4$^{th}$ Plan Assumptions)**

## Long-Term Forecasts of Aluminum Smelter Electricity Demand

For the long-term medium forecast, the 2005 forecast level is extended to the end of the forecast in 2025. Figure A-17 shows the medium total DSI demand assumptions extended to 2025 compared to the forecasts in the Council's Fourth Power Plan. In this figure, non-aluminum DSI loads of 60 average megawatts have been added to the aluminum forecast. Again, this forecast does not imply that Bonneville will serve all of this DSI demand; it has been labeled DSI for convenience. The medium case is 1,260 average megawatts below the forecast in the Council's last power plan.

Although the loads after 2005 are shown as constant, we would actually expect them to be quite volatile around that trend. In addition, since aluminum prices are expected to trend downward over time, and natural gas prices upward, it may become increasingly difficult for regional smelters to operate as the future unfolds.

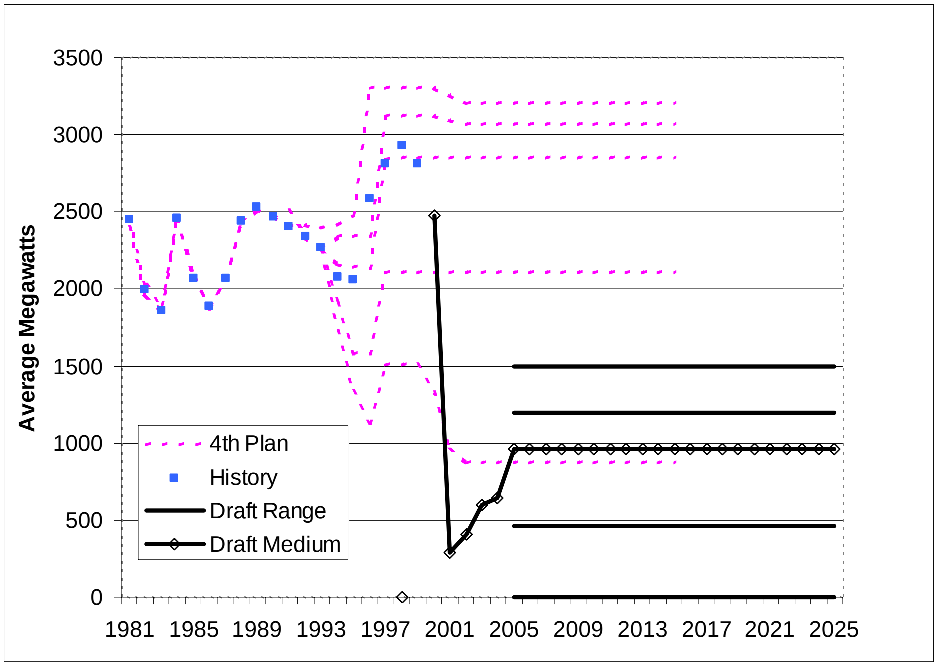



**Figure A-17: Demand Assumptions for DSI Industries Compared to Fourth Plan Assumptions**

In all previous power plans, the Council has assumed a range of DSI demands. The high DSI demand assumption was paired with the high economic assumptions and demand forecast. This pairing of aluminum and other forecasting assumptions was based on the theory that aluminum prices would be the key variable and that aluminum prices were likely to be positively correlated with rates of economic growth. For illustrative purposes, a similar approach has been used to develop a range of aluminum demand assumptions. Figure A-18 shows the aluminum demand assumptions included in each forecast case for the Council's Fourth Power Plan compared to the outlook now.

Only in the low forecast of the Fourth Power Plan was there a large reduction of aluminum demand. It was assumed that Bonneville or other relatively affordable power would be available to the aluminum plants. Thus, most of the plants were assumed to remain competitive, or at least operate as swing plants, in the medium case. Now the expectation is that only between zero and four of the region's smelters could survive to operate at significant capacity factors.

The expectation of higher electricity prices and rapid expansion of aluminum smelting capacity in China and other areas has changed the outlook for the region's smelters substantially. Aluminum prices are still important, but the cost of electricity has become a critical element for Northwest smelters. Since electricity prices are related to natural gas prices in the long-term, and high natural gas prices are associated with the high economic growth case, it is also reasonable to expect that lower aluminum demand could be associated with the higher economic growth cases. However, if high aluminum prices are still associated with higher economic growth, then it is possible that the high economic growth cases will favor aluminum plant operation given that electricity prices are not too high. In short, it is not clear how aluminum demand will be related to the economic growth conditions. The proposed solution to this dilemma is to forecast aluminum electricity demand separately from other demands for electricity.

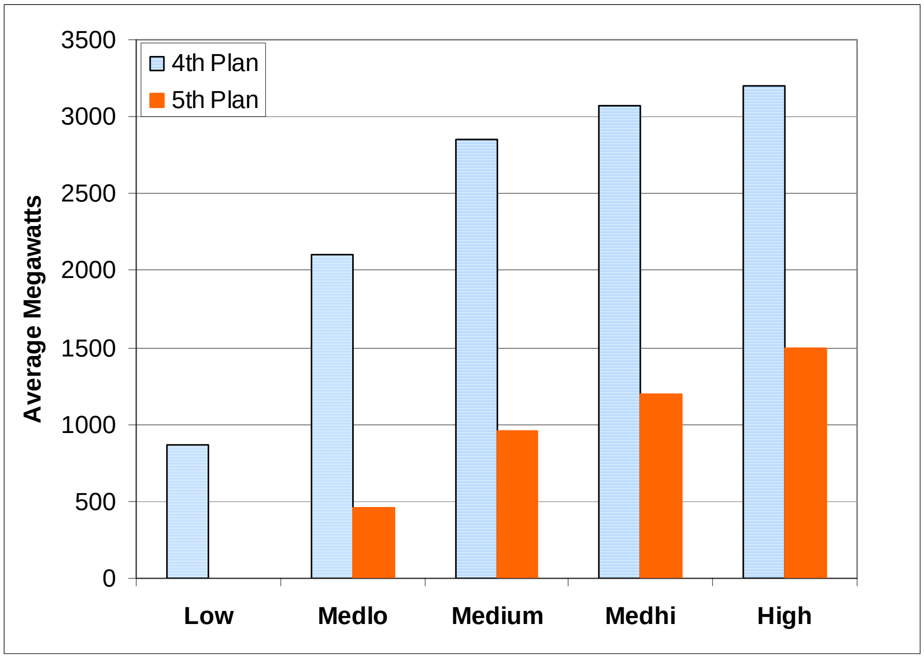



**Figure A-18: Aluminum Electricity Demand Assumptions for 2005-2025 Compared to the Council's Fourth Power Plan**

Therefore, the Council is modeling aluminum industry demands explicitly in its portfolio model.

### Aluminum Demand in the Portfolio Analysis

Since aluminum demands are very significant in determining future electricity demands of the region, they are an important source of uncertainty that should be modeled and addressed directly in the Council's resource planning process. In developing the Fifth Power Plan, the Council modeled aluminum plants as uncertain loads that depend on aluminum prices and electricity prices. This was done using the Council's portfolio analysis model. The simple model described above was the basis for the relationship between aluminum electricity demand and electricity and aluminum prices developed for the portfolio model. As it simulated alternative futures, the portfolio model randomly selected different electricity prices and aluminum prices. These conditions were used to estimate the aluminum plants' demand for electricity.

However, the simulations contained in the portfolio model take into account, in addition to the basic cost information for each plant, assumptions about cost of shutting down and restarting plants and minimum down time and up time. For example, it is assumed that the decision to restart a plant would include the startup costs and that, if a plant were to reopen, it would remain open for at least 9 months. Similarly, a plant may not close immediately when current prices make it unprofitable, and once it does close it would likely remain closed for a period of at least 9 months. The portfolio model also assumes that if a plant does not operate for a five-year period, it will be permanently closed. The portfolio model goes beyond these calculations to consider the value of an aluminum plant interruption option to Bonneville or the regional power system.

The base case portfolio model simulations are less optimistic about the operation of the aluminum plants than the discrete assumptions described in the earlier section of this appendix. In 80 percent of the futures, aluminum electricity use was expected to be zero. The mean electricity demand for the plants decreased from about 100 average megawatts in the early years down to about 60 average megawatts in the later years. This compares to the medium discrete assumption of 958 average megawatts. There are futures examined in which aluminum loads vary between 800 and 1500 average megawatts although such futures are infrequent. If it were assumed that the region needed to stand ready to meet these loads, this is roughly consistent with the discrete range of DSI forecasts discussed above.

## NEW DIMENSIONS OF COUNCIL DEMAND FORECASTING

Changing electricity markets are changing the planning requirements for the region. Electricity prices in the Pacific Northwest are related directly to demand and supply conditions, not just in the region, but also in the entire interconnected Western United States. In addition, electricity markets have been, and are expected to remain, volatile. Shortages and high prices will occur at specific times of the year and day depending on electricity demand, but can be prolonged in cases of poor hydroelectric conditions, such as occurred in 2001.

Evaluating electricity markets requires assumptions about demand growth in the entire West and some understanding of how the demand will vary across different seasons and across hours of the day. The following sections describe the simple approaches used to develop assumptions about future patterns of electricity consumption and predicted growth in demand throughout the rest of the West.

### Patterns of Regional Electricity Consumption

One approach to forecasting temporal patterns of demand is to use the monthly and hourly patterns from the Fourth Power Plan. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate hourly demand patterns in the future. That model was not used for this forecast, but the hourly patterns remain similar. Another approach is to use historical patterns of demand. In practice, these approaches do not result in significantly different monthly patterns of consumption.

Whatever typical monthly shape is used, specific months can depart from the normal pattern depending on weather. Variability in consumption patterns due to weather events were considered in the portfolio planning model that addresses mitigation of risk and uncertainty in electricity markets. Typical monthly patterns provide a starting point for that analysis. The same is true for the peak demand forecast and the typical hourly patterns of demand.

### Monthly Patterns of Regional Demand

Figure A-19 compares monthly patterns of regional demand in 1999 with patterns from the Council's Load Shape Forecasting System (LSFS) from the Fourth Power Plan simulation for 1995. The points on this graph indicate the monthly consumption of electricity compared to the annual average. These patterns have been adjusted to reflect only non-DSI demand. DSI demands, dominated by aluminum plants, tend to be seasonally flat.

The monthly patterns of both the actual and modeled demand reflect the higher electricity consumption in the winter with a secondary and smaller increase during the summer. Within that general pattern, there appear variations in specific months. The LSFS was based on a year in which there was a severe cold event in December. A particular year was chosen to design the model rather than an average over several years to preserve the variability in the load patterns. Averaging would have tended to flatten the hourly variation masking some of the potential volatility.

For purposes of this forecast, the 1999 pattern is used. Table A-6 shows the monthly demand shape in numerical terms.

**Table A-6: Monthly Non-DSI Electricity Consumption Pattern**

| Month | Shape Factor |
|---|---|
| January | 1.140 |
| February | 1.097 |
| March | 1.020 |
| April | 0.943 |
| May | 0.921 |
| June | 0.938 |
| July | 0.969 |
| August | 0.957 |
| September | 0.911 |
| October | 0.940 |
| November | 1.033 |
| December | 1.185 |

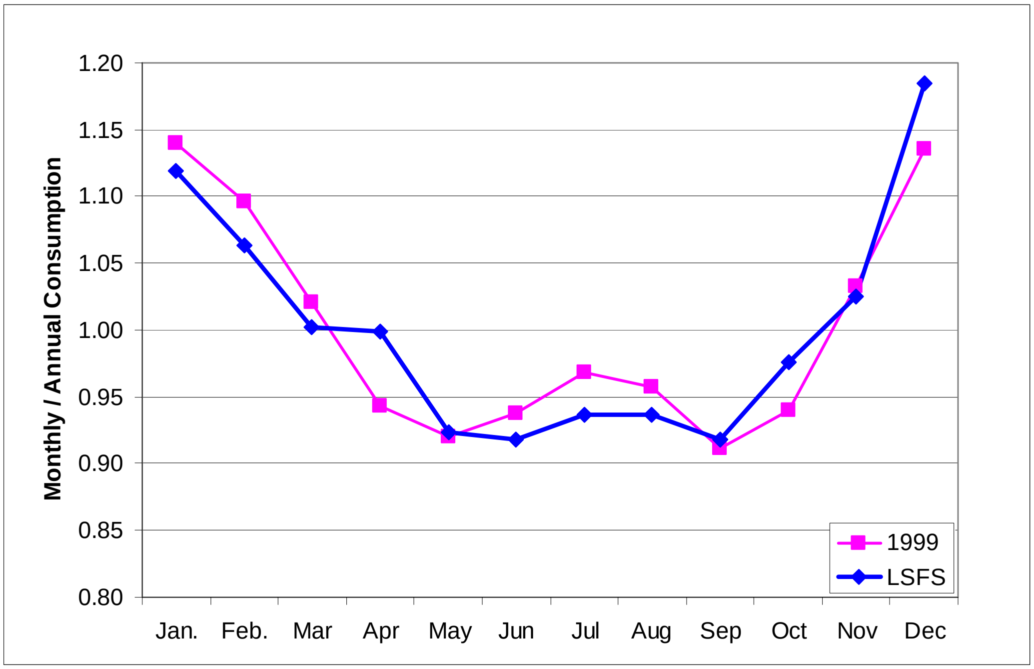



**Figure A-19: Monthly Patterns of Non-DSI Electricity Use**

## Regional Peak Demand

Monthly regional peak demands are also taken from the Council's Load Shape Forecasting System. Figure A-20 shows average monthly consumption compared to monthly peak hour consumption. Peak demand is highest relative to average monthly demand in the winter months. For example, estimated January peak demand is 45 percent higher than the average demand for the month, whereas the peak August demand is only 21 percent higher than average August demand. The summer and winter peak demands occur at different times of the day. In June, July and August, peak demand hours are at 2:00 or 3:00 in the afternoon. The rest of the year peak demand occurs at 8:00 or 9:00 in the morning.

The ratio of average monthly demand to peak hour demand in a month is referred to as a "load factor." Over time the LSFS predicts that load factors will decline, especially during the winter months. That is, the peak hour demand will increase faster than the average monthly demand over time. Figure A-21 shows predicted load factors for 1995, 2005 and 2015 from the LSFS analysis of the Fourth Power Plan forecasts. The change in load factor is most pronounced in the winter months. Discussion with the Council's Demand Forecasting Advisory Committee indicated that utilities are experiencing increases in summer peak loads, probably due to an increasing presence of air conditioning in the region. In the future, the Council should investigate this trend further to see if the forecasted pattern needs to be modified to reflect a greater decrease in summer load factors.

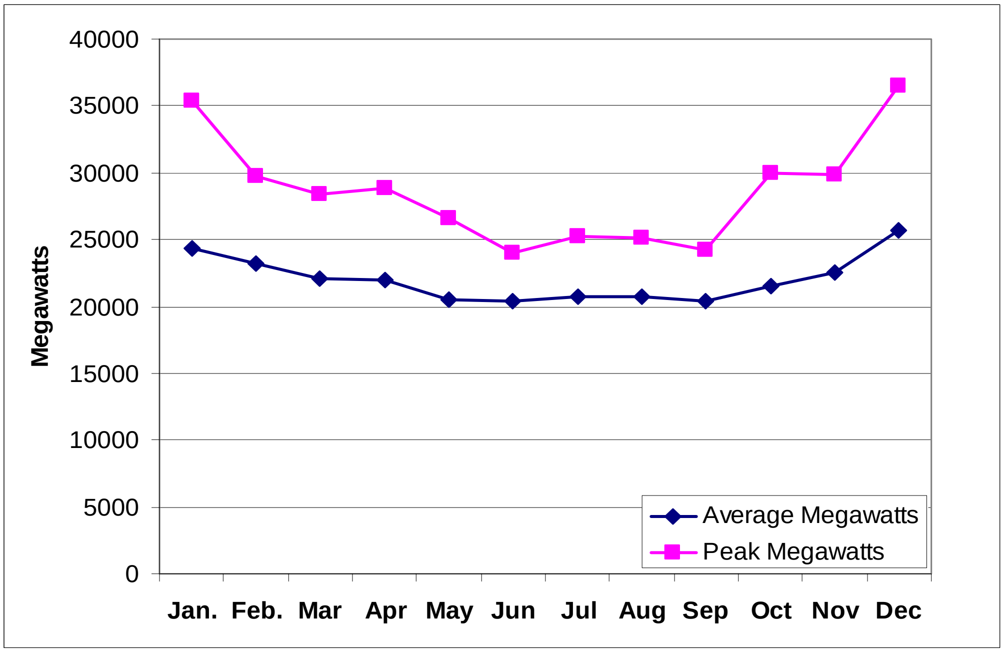



**Figure A-20: Hourly Peak Demand Compared to Average Monthly Demand**

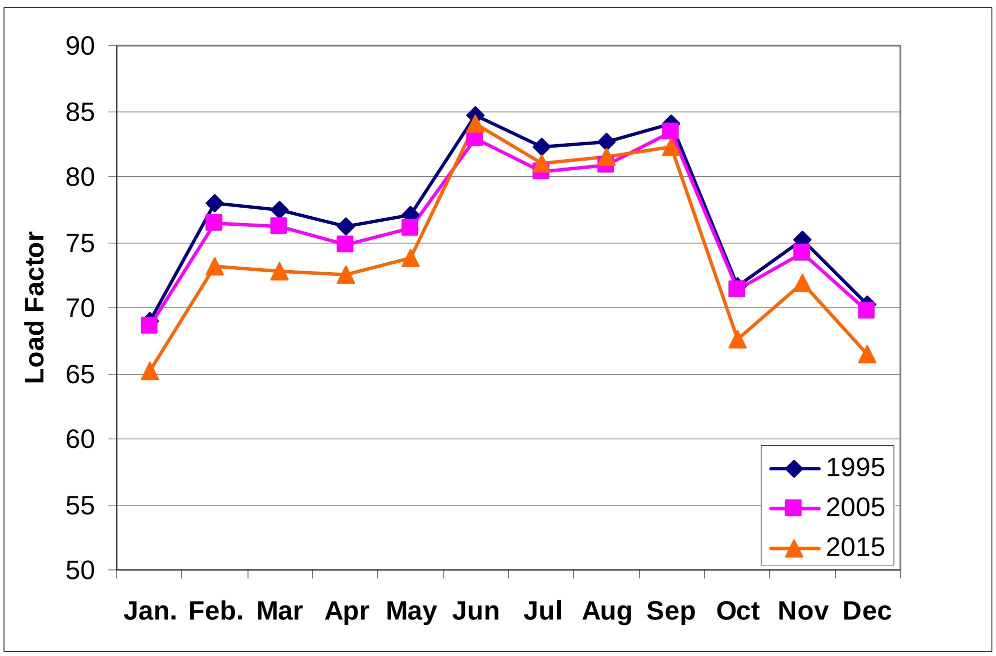



**Figure A-21: Forecast of Electricity Demand Load Factors**

## Regional Hourly Demand Patterns

The LSFS forecasts hourly demand for 8,760 hours in the year. It does this for individual end uses within the commercial and residential sectors, for specific manufacturing sectors, and for irrigation. These hourly patterns are aggregated to obtain total hourly demand in the region. Figure A-22 illustrates hourly shapes for a typical winter weekday, a very cold winter weekday, and a summer weekday. Winter demand peaks in the morning and again in the evening. This pattern is driven largely by residential demand patterns, which are more variable across the hours of the day than the other sectors.

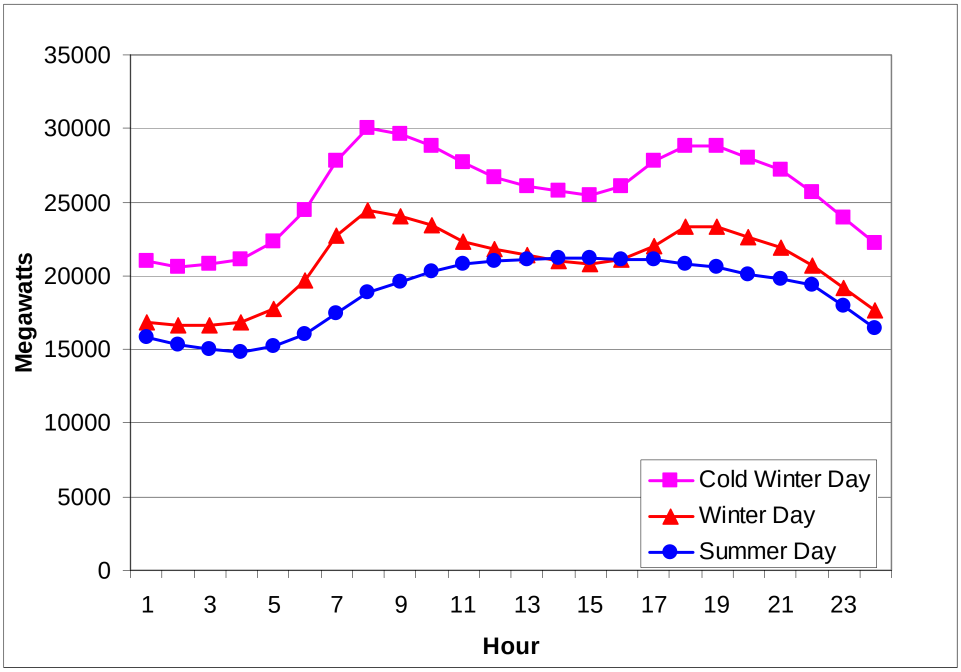



**Figure A-22: Illustrative Hourly Demand Patterns in a Day**

These hourly patterns of demand may be used in various ways to address analytical requirements. In the Fourth Power Plan, for example, they were aggregated into four distinct blocks of demand for a week. These included on-peak, shoulder, off-peak, and minimum load hours.[7] This was done to address sustained peaking requirements in the plan. By estimating an hourly pattern for 8,760 hours in a year, flexibility is provided to aggregate the demand patterns for different types of analysis.

### Portfolio Model Analysis of Non-DSI Demand

The portfolio model goes beyond the typical demand trends and their normal seasonal and hourly patterns. It introduces random variations in loads. There are three types of variation considered. The model chooses among potential long-term trends encompassed in the range of demand forecasts discussed above as past Council plans have done. But the portfolio model also adds shorter-term excursions that reflect such events as business cycles and energy commodity price cycles, and very short-term variations such as would be caused by weather events.

Figure A-23 illustrates a few specific demand paths, from hundreds simulated, and compares them to the long-term range of non-DSI demand forecasts.

[7] See "Draft Fourth Northwest Conservation and Electric Power Plan," Appendix D, p. D-36.

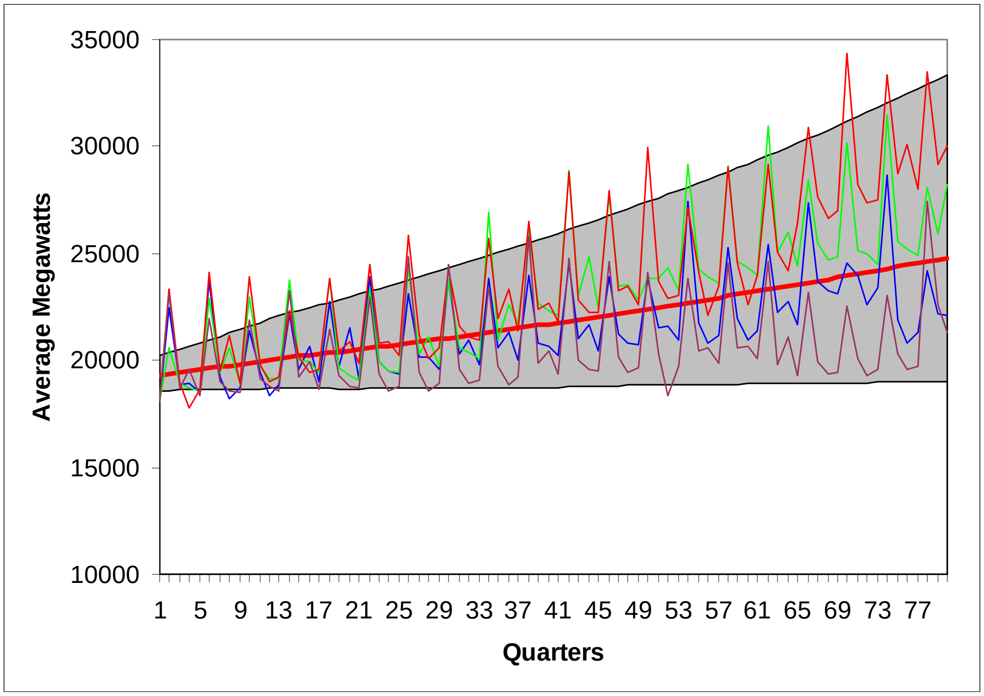



**Figure A-23: Illustrative Non-DSI Demand Paths from the Portfolio Model Compared to the Trend Forecast Range**

## Electricity Demand Growth in the Rest of the West

In previous power plans, the Council has not concerned itself with demand growth in other parts of the West. However, as noted earlier, this is now an important consideration for analysis of future electricity prices in this region.

A simple approach was used to estimate electricity demand growth for other areas of the West. The areas used by the AURORA® electricity market model dictate the specific areas considered. The general approach used, although it varies for some areas, is to calculate future growth in electricity demand as a historical growth rate of electricity use per capita times a forecast of population growth rate for the area. The exceptions to this method were California, where forecasts by the California Energy Commission were used, the Pacific Northwest, and the Canadian provinces, where electricity demand forecasts were directly available from the National Energy Board.

Population forecasts for states are available from the U.S. Census Bureau web site. However, the Census forecasts were replaced by more recent state forecasts when they could be identified. For example, Nevada population forecasts were taken from the Nevada Department of Water Resources. There were two reasons for this. First, the AURORA® model distinguishes between Northern and Southern Nevada and Census forecasts were only available at the state level. Second, the Census Bureau forecast showed Nevada population growing at only .85 percent a year, whereas Nevada has recently been the fastest growing state in the nation with population growth in the neighborhood of 5 percent a year. Other population forecast sources used were the Colorado Department of Labor Affairs, the Arizona Department of Economic Security, Pacificorp's Integrated Resource Plan for Utah, and the Wyoming Department of Administration and Information.

Electricity consumption per capita varies substantially among the states in the West, as have their patterns of change over time.  Figure A-24 shows electricity use per capita for Western states from 1960 to 1999.  The most spectacular change is for Wyoming, which started out in 1960 with the lowest use per capita and grew to substantially higher than any other state.  This may reflect significant heavy industrial growth in electricity intensive, but low employment, plants, oil and natural gas production, for example.  The Pacific Northwest states are the highest per capita users of electricity, reflecting a past of very low electricity prices and a heavy presence of aluminum smelters.  California is the lowest user of electricity per capita, followed by New Mexico, Utah and Colorado, which are all very similar to one another.  Nevada and Arizona fall between these three states and the Pacific Northwest states.

The general pattern is substantial growth in electricity use per capita until about 1980.  After 1980, most states' electricity use per capita levels off or actually declines.  Exceptions to this pattern are Colorado, New Mexico, Arizona, and Utah where use per capita has slowed, but continued growing.

The Pacific Northwest was a special case.  In AURORA®, the Pacific Northwest is divided into four areas; Western Oregon and Washington (west of the Cascade Mountains), Eastern Oregon and Washington combined with Northern Idaho, Southern Idaho, and Montana.  The sum of these area forecasts should be consistent with the 20-year regional forecast discussed earlier. One approach would have been to share the regional demand forecast to areas based on historical shares.  However, in order to recognize that areas within the Pacific Northwest have not grown uniformly, the forecast area growth rates were modified to reflect historical relative population growth in the four areas while maintaining consistency with the total regional population growth.

Table A-7 shows the forecast growth rates for the AURORA® demand areas.  They are average annual growth rates from 2000 to 2025.

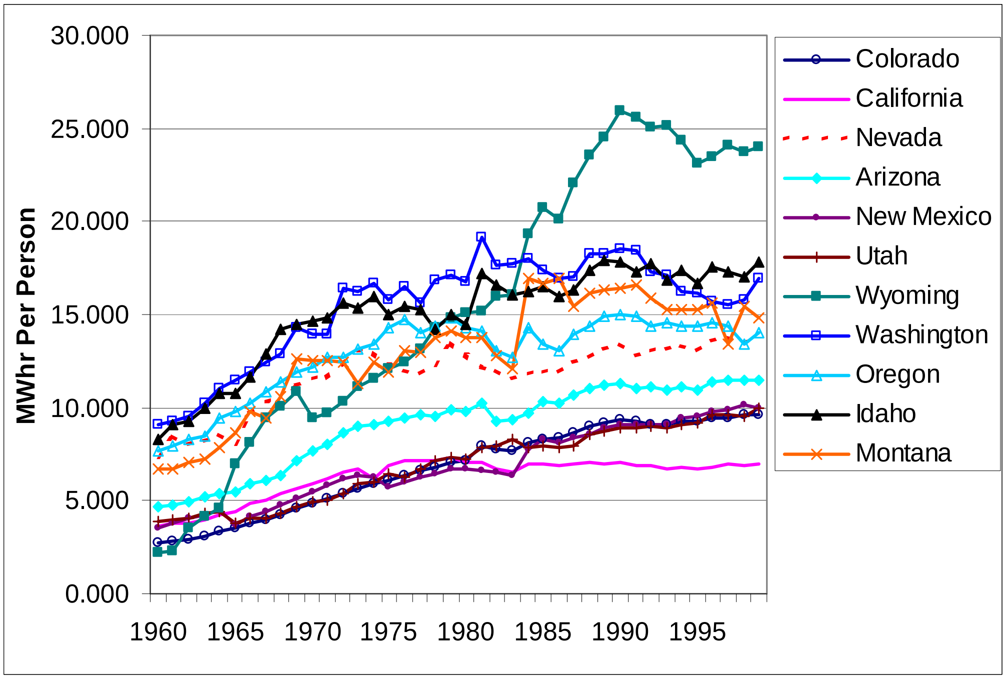



**Figure A-24: State Electricity Use Per Capita: 1960 to 1999**

**Table A-7: Forecast Electricity Demand Growth Rates for Western Demand Areas**

| Area | Annual Growth Rate |
|---|---|
| PNW Western OR+WA | 1.06 |
| PNW Eastern OR+WA and Northern ID | 0.42 |
| PNW Southern ID | 1.50 |
| PNW MT | 0.63 |
| Northern CA | 1.51 |
| Southern CA | 1.62 |
| Northern NV | 2.12 |
| Southern NV | 2.72 |
| WY | 0.62 |
| UT | 2.80 |
| CO | 2.34 |
| NM | 3.05 |
| AZ | 2.47 |
| Alberta | 1.59 |
| British Columbia | 1.39 |

## FUTURE FORECASTING METHODS

At the time the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of the historically rapid growth of electricity use, and the future of several proposed nuclear and coal generating plants was in question. It was important for the Council's Demand Forecasting System (DFS) to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends were no longer reliable. In addition, the requirement of the Northwest Power Act for a balanced consideration of both conservation and new generation placed another requirement on the DFS; it needed to support the detailed evaluation of improved efficiency opportunities and their effects on electricity demand.

These analytical requirements necessitated an extremely detailed approach to demand forecasting. Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that built demand forecasts from the end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models required detailed economic forecasts for all the sectors represented separately in the demand models. The models also required forecasts of demographic trends, electricity prices and fuel prices.

Before the last power plan update, a significant new component was added to the DFS. As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to arise in the region, it became clear that we needed to understand the patterns of electricity demand over seasons, months and hours of the day. Therefore the Load Shape Forecasting System (LSFS) was developed. This model builds up the hourly shape of demand based on the underlying hourly shapes of electricity use by the different types of end-use equipment. It contains about the same detail as the DFS, but when multiplied by 8,760 hours per year, a one-year forecast can contain 400 million values.

The detailed approaches of the DFS and LSFS are expensive and time consuming. Major efforts are involved in collecting detailed end-use data, building the models, and maintaining and operating the systems. Neither the current planning issues, nor the available data and resources seem to support the continued use of the old demand forecasting approach. The Council developed an issue paper on forecasting methods in May 2001 to explore alternative approaches.[8] It was agreed that it was not possible for the Council to employ the forecasting models for the Fifth Power Plan. However, there was little consensus in the region about what changes should be made to the forecasting system for future Council planning.

The basic priorities for a demand forecast have changed. Although the Northwest Power Act still requires a 20-year forecast of demand, there are few decisions that need to be made today to meet growing electricity demands beyond the next five years. The lead-time required to put new generating resources in place has been reduced substantially from the large scale nuclear and coal plants that appeared to be desirable in the early 1980s. In addition, the restructuring of the wholesale electricity markets to rely more on competitively developed supplies means there is a less clear role for the Council's planning which focused on the type and timing of new resources to be acquired.

The focus of the Council's power activity has shifted to the evaluation of the performance of more competitive power markets and how to acquire conservation in the new market. The Council also has been concerned about the likelihood of competitive wholesale power markets

[8] Northwest Power Planning Council. "Council Demand Forecasting Issues." May 2001, Council document number 2001-13. http://www.nwcouncil.org/library/2001/2001-13.htm

providing adequate and reliable power supplies, which has three implications for demand forecasting. First, the focus is much shorter term. Adequacy and reliability depend on generating resources, including water conditions and their effects of hydroelectric generation, compared to loads. The question facing the region recently has been whether there is adequate capacity and energy to meet the coming winter demand. Second, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and adequacy of supply are now determined by West-wide electricity conditions. The AURORA® electricity market model that the Council is using requires assumptions about demand growth for all areas of the Western integrated electricity grid. Third, the temporal patterns of demand and peak demands matter more. The region is becoming more likely to be constrained by sustained peaking capability than average annual energy supplies, as it was in the past. Further, the rest of the West has always been capacity constrained and thus peak prices throughout the West can be expected during peak demand periods.

Thus, for purposes of demand forecasting, the requirements of the forecast are shifting to shorter term, temporal patterns, and expanded geographic areas. This implies that a different type of demand forecasting system may be useful for future Council planning. However, there remains the question of estimated potential efficiency gains in the use of electricity. To assess cost-effective conservation potential, the end-use detail of the old forecasting models would still be useful. But even if the Council still had the resources to use the old forecasting models, the detailed data necessary to update the models does not exist. Finding new ways of assessing conservation potential, or of encouraging its adoption without explicit estimates of the amount likely to be saved, is a significant issue for regional planning.

The forecasts presented in this paper are based on an extension of the previous Council plan and relatively simple approaches to expanding the geographic and temporal dimensions of the forecast. The Council needs to invest in new forecasting approaches for future power plans. One of the activities for the Council over the next several years will be to develop a new forecasting system that is better oriented to the available Council resources, to the current planning issues, and to the available data regarding electricity consumption and its driving variables. The Council welcomes suggested approaches and advice in this area.

# Fifth Power Plan Demand Forecast D2
## Medium Case

| | 2000 (Actual) | 2005 | 2010 | 2015 | 2020 | 2025 | Growth Rates 2000-2025 | 2000-2015 | 2005-2025 |
|---|---|---|---|---|---|---|---|---|---|
| **Total Sales** | 20080 | 19391 | 20646 | 22105 | 23701 | 25423 | 0.95 | 0.64 | 1.36 |
| **Non-DSI Sales** | 17603 | 18433 | 19688 | 21147 | 22742 | 24464 | 1.33 | 1.23 | 1.43 |
| **Residential** | 6724 | 7262 | 7687 | 8230 | 8809 | 9430 | 1.36 | 1.36 | 1.31 |
| **Commercial** | 5219 | 5453 | 5771 | 6146 | 6556 | 6993 | 1.18 | 1.10 | 1.25 |
| **Non-DSI Industrial** | 4836 | 4904 | 5397 | 5919 | 6505 | 7150 | 1.58 | 1.36 | 1.90 |
| **DSI Industrial** | 2477 | 958 | 958 | 958 | 958 | 958 | -3.73 | -6.13 | 0.00 |
| **Irrigation** | 652 | 629 | 641 | 654 | 667 | 681 | 0.17 | 0.02 | 0.40 |
| **Other** | 172 | 185 | 191 | 198 | 204 | 211 | 0.82 | 0.93 | 0.66 |

**Total**

| | 2000 (Actual) | 2015 | 2025 | Growth Rates 2000-2015 | 2000-2025 |
|---|---|---|---|---|---|
| **Low** | 20080 | 17489 | 17822 | -0.92 | -0.48 |
| **Medium Low** | 20080 | 19942 | 21934 | -0.05 | 0.35 |
| **Medium** | 20080 | 22105 | 25423 | 0.64 | 0.95 |
| **Medium High** | 20080 | 24200 | 29138 | 1.25 | 1.50 |
| **High** | 20080 | 27687 | 35897 | 2.16 | 2.35 |

**Non-DSI**

| | 2000 (Actual) | 2015 | 2025 | Growth Rates 2000-2015 | 2000-2025 |
|---|---|---|---|---|---|
| **Low** | 17603 | 17489 | 17822 | -0.04% | 0.05% |
| **Medium Low** | 17603 | 19482 | 21474 | 0.68% | 0.80% |
| **Medium** | 17603 | 21147 | 24464 | 1.23% | 1.33% |
| **Medium High** | 17603 | 23000 | 27937 | 1.80% | 1.86% |
| **High** | 17603 | 26187 | 34397 | 2.68% | 2.72% |

**Total Demand**

| Weather Adjusted Sales Actual | YEAR | Revised Forecast Low | Medlo | Medium | Medhi | High |
|---|---|---|---|---|---|---|
| 15533 | 1981 | | | | | |
| 14767 | 1982 | | | | | |
| 14448 | 1983 | | | | | |
| 15477 | 1984 | | | | | |
| 15194 | 1985 | | | | | |
| 15352 | 1986 | | | | | |
| 15872 | 1987 | | | | | |
| 16683 | 1988 | | | | | |
| 17356 | 1989 | | | | | |
| 17549 | 1990 | | | | | |
| 17903 | 1991 | | | | | |
| 17994 | 1992 | | | | | |
| 18021 | 1993 | | | | | |
| 18385 | 1994 | | | | | |
| 18647 | 1995 | | | | | |
| 19099 | 1996 | | | | | |
| 19685 | 1997 | | | | | |
| 19967 | 1998 | | | | | |
| 20487 | 1999 | | | | | |
| 20082 | 2000 | | | 20080 | | |
| 17235 | 2001 | | | 17415 | | |
| | 2002 | | | 17565 | | |
| | 2003 | | | 18145 | | |
| | 2004 | | | 18714 | | |
| | 2005 | 17191 | 18284 | 19391 | 20220 | 21721 |
| | 2006 | 17200 | 18415 | 19621 | 20560 | 22227 |
| | 2007 | 17214 | 18558 | 19864 | 20921 | 22757 |
| | 2008 | 17228 | 18699 | 20103 | 21294 | 23314 |
| | 2009 | 17257 | 18858 | 20363 | 21679 | 23897 |
| | 2010 | 17297 | 19030 | 20646 | 22079 | 24507 |
| | 2011 | 17320 | 19189 | 20917 | 22476 | 25098 |
| | 2012 | 17353 | 19366 | 21209 | 22897 | 25714 |
| | 2013 | 17366 | 19527 | 21480 | 23307 | 26343 |
| | 2014 | 17430 | 19734 | 21789 | 23748 | 27001 |
| | 2015 | 17489 | 19942 | 22105 | 24200 | 27687 |
| | 2016 | 17522 | 20132 | 22415 | 24649 | 28406 |
| | 2017 | 17554 | 20324 | 22729 | 25108 | 29145 |
| | 2018 | 17586 | 20518 | 23048 | 25576 | 29907 |
| | 2019 | 17619 | 20714 | 23372 | 26053 | 30690 |
| | 2020 | 17652 | 20913 | 23701 | 26541 | 31497 |
| | 2021 | 17686 | 21113 | 24035 | 27039 | 32327 |
| | 2022 | 17719 | 21315 | 24374 | 27547 | 33181 |
| | 2023 | 17753 | 21519 | 24718 | 28066 | 34060 |
| | 2024 | 17787 | 21725 | 25068 | 28596 | 34966 |
| | 2025 | 17822 | 21934 | 25423 | 29138 | 35897 |
| | | | | | | |
| Growth Rate | 2005-25 | 0.18% | 0.91% | 1.36% | 1.84% | 2.54% |
| Growth Rate | 2000-25 | -0.48% | 0.35% | 0.95% | 1.50% | 2.35% |

**Total Non-DSI Demand**

| Weather Adjusted Sales Actual | YEAR | Revised Forecast Low | Medlo | Medium | Medhi | High |
|---|---|---|---|---|---|---|
| 13085 | 1981 | | | | | |
| 12774 | 1982 | | | | | |
| 12588 | 1983 | | | | | |
| 13019 | 1984 | | | | | |
| 13126 | 1985 | | | | | |
| 13467 | 1986 | | | | | |
| 13807 | 1987 | | | | | |
| 14248 | 1988 | | | | | |
| 14825 | 1989 | | | | | |
| 15084 | 1990 | | | | | |
| 15496 | 1991 | | | | | |
| 15653 | 1992 | | | | | |
| 15756 | 1993 | | | | | |
| 16310 | 1994 | | | | | |
| 16589 | 1995 | | | | | |
| 16519 | 1996 | | | | | |
| 16871 | 1997 | | | | | |
| 17034 | 1998 | | | | | |
| 17464 | 1999 | | | | | |
| 17605 | 2000 | | | 17603 | | |
| | 2001 | | | 17129 | | |
| | 2002 | | | 17152 | | |
| | 2003 | | | 17545 | | |
| | 2004 | | | 18072 | | |
| | 2005 | 17191 | 17824 | 18433 | 19020 | 20221 |
| | 2006 | 17200 | 17955 | 18663 | 19360 | 20727 |
| | 2007 | 17214 | 18098 | 18906 | 19721 | 21257 |
| | 2008 | 17228 | 18239 | 19145 | 20093 | 21814 |
| | 2009 | 17257 | 18398 | 19405 | 20479 | 22397 |
| | 2010 | 17297 | 18570 | 19688 | 20879 | 23007 |
| | 2011 | 17320 | 18729 | 19959 | 21275 | 23598 |
| | 2012 | 17353 | 18906 | 20251 | 21696 | 24214 |
| | 2013 | 17366 | 19067 | 20521 | 22106 | 24843 |
| | 2014 | 17430 | 19274 | 20830 | 22547 | 25501 |
| | 2015 | 17489 | 19482 | 21147 | 23000 | 26187 |
| | 2016 | 17522 | 19672 | 21456 | 23449 | 26906 |
| | 2017 | 17554 | 19864 | 21770 | 23907 | 27645 |
| | 2018 | 17586 | 20058 | 22089 | 24375 | 28407 |
| | 2019 | 17619 | 20254 | 22413 | 24853 | 29190 |
| | 2020 | 17652 | 20453 | 22742 | 25341 | 29997 |
| | 2021 | 17686 | 20653 | 23076 | 25839 | 30827 |
| | 2022 | 17719 | 20855 | 23415 | 26347 | 31681 |
| | 2023 | 17753 | 21059 | 23760 | 26866 | 32560 |
| | 2024 | 17787 | 21265 | 24109 | 27396 | 33466 |
| | 2025 | 17822 | 21474 | 24464 | 27937 | 34397 |
| Growth Rate | 2005-25 | 0.18% | 0.94% | 1.43% | 1.94% | 2.69% |
| Growth Rate | 2000-25 | 0.05% | 0.80% | 1.33% | 1.86% | 2.72% |

**Residential Demand**

| | Revised Forecast | | | | |
|---|---|---|---|---|---|
| | Low | Medlo | Medium | Medhi | High |
| 2000 | | | 6724 | | |
| 2001 | 6397 | 6759 | 6797 | 6876 | 7093 |
| 2002 | 6642 | 6722 | 6784 | 6883 | 7162 |
| 2003 | 6857 | 6902 | 6987 | 7110 | 7462 |
| 2004 | 6837 | 7069 | 7183 | 7333 | 7767 |
| 2005 | 6728 | 7122 | 7262 | 7437 | 7955 |
| 2006 | 6728 | 7178 | 7340 | 7545 | 8124 |
| 2007 | 6735 | 7244 | 7428 | 7665 | 8305 |
| 2008 | 6731 | 7299 | 7505 | 7777 | 8484 |
| 2009 | 6734 | 7362 | 7589 | 7894 | 8673 |
| 2010 | 6747 | 7436 | 7687 | 8021 | 8876 |
| 2011 | 6768 | 7517 | 7789 | 8159 | 9077 |
| 2012 | 6793 | 7599 | 7896 | 8302 | 9280 |
| 2013 | 6801 | 7668 | 7986 | 8430 | 9472 |
| 2014 | 6838 | 7765 | 8103 | 8584 | 9688 |
| 2015 | 6878 | 7869 | 8230 | 8747 | 9918 |
| 2016 | 6890 | 7954 | 8343 | 8900 | 10167 |
| 2017 | 6902 | 8040 | 8457 | 9056 | 10423 |
| 2018 | 6915 | 8126 | 8573 | 9214 | 10684 |
| 2019 | 6927 | 8214 | 8690 | 9376 | 10952 |
| 2020 | 6940 | 8303 | 8809 | 9540 | 11227 |
| 2021 | 6952 | 8393 | 8930 | 9707 | 11509 |
| 2022 | 6965 | 8483 | 9052 | 9876 | 11798 |
| 2023 | 6977 | 8575 | 9176 | 10049 | 12094 |
| 2024 | 6990 | 8667 | 9302 | 10225 | 12398 |
| 2025 | 7002 | 8761 | 9430 | 10404 | 12709 |
| Growth 2000-25 | 0.16% | 1.06% | 1.36% | 1.76% | 2.58% |

**Commercial Demand**

| | Revised Forecast | | | | |
|---|---|---|---|---|---|
| | Low | Medlo | Medium | Medhi | High |
| 2000 | | | 5219 | | |
| 2001 | 5043 | 5064 | 5083 | 5184 | 5319 |
| 2002 | 5218 | 5240 | 5124 | 5248 | 5427 |
| 2003 | 5260 | 5281 | 5201 | 5348 | 5576 |
| 2004 | 5357 | 5377 | 5378 | 5560 | 5842 |
| 2005 | 5255 | 5274 | 5453 | 5670 | 6008 |
| 2006 | 5267 | 5306 | 5509 | 5763 | 6148 |
| 2007 | 5276 | 5338 | 5564 | 5858 | 6292 |
| 2008 | 5293 | 5378 | 5627 | 5965 | 6450 |
| 2009 | 5317 | 5425 | 5696 | 6075 | 6614 |
| 2010 | 5340 | 5472 | 5771 | 6184 | 6780 |
| 2011 | 5348 | 5507 | 5835 | 6284 | 6932 |
| 2012 | 5367 | 5558 | 5914 | 6398 | 7100 |
| 2013 | 5387 | 5611 | 5988 | 6514 | 7280 |
| 2014 | 5425 | 5676 | 6070 | 6631 | 7455 |
| 2015 | 5455 | 5735 | 6146 | 6743 | 7631 |
| 2016 | 5485 | 5795 | 6226 | 6856 | 7811 |
| 2017 | 5515 | 5855 | 6307 | 6972 | 7996 |
| 2018 | 5545 | 5916 | 6389 | 7089 | 8184 |
| 2019 | 5576 | 5978 | 6472 | 7209 | 8378 |
| 2020 | 5607 | 6040 | 6556 | 7330 | 8576 |
| 2021 | 5638 | 6103 | 6641 | 7454 | 8778 |
| 2022 | 5669 | 6166 | 6727 | 7580 | 8986 |
| 2023 | 5700 | 6231 | 6815 | 7707 | 9198 |
| 2024 | 5732 | 6295 | 6904 | 7837 | 9415 |
| 2025 | 5763 | 6361 | 6993 | 7969 | 9638 |
| Growth 2000-25 | 0.40% | 0.79% | 1.18% | 1.71% | 2.48% |

**Industrial Non-DSI Demand**

| | Revised Forecast | | | | |
|---|---|---|---|---|---|
| | Low | Medlo | Medium | Medhi | High |
| 2000 | 4737 | 4770 | 4836 | 4833 | 4851 |
| 2001 | 4239 | 4303 | 4401 | 4454 | 4589 |
| 2002 | 4245 | 4344 | 4484 | 4567 | 4744 |
| 2003 | 4277 | 4411 | 4596 | 4710 | 4933 |
| 2004 | 4297 | 4469 | 4702 | 4850 | 5124 |
| 2005 | 4402 | 4616 | 4904 | 5092 | 5429 |
| 2006 | 4402 | 4657 | 4997 | 5225 | 5618 |
| 2007 | 4403 | 4700 | 5092 | 5365 | 5817 |
| 2008 | 4405 | 4743 | 5189 | 5511 | 6027 |
| 2009 | 4410 | 4789 | 5291 | 5662 | 6248 |
| 2010 | 4415 | 4836 | 5397 | 5818 | 6480 |
| 2011 | 4410 | 4878 | 5498 | 5970 | 6709 |
| 2012 | 4403 | 4918 | 5601 | 6128 | 6947 |
| 2013 | 4391 | 4957 | 5703 | 6287 | 7194 |
| 2014 | 4384 | 5000 | 5808 | 6453 | 7454 |
| 2015 | 4377 | 5044 | 5919 | 6626 | 7726 |
| 2016 | 4370 | 5088 | 6032 | 6803 | 8009 |
| 2017 | 4364 | 5133 | 6147 | 6985 | 8301 |
| 2018 | 4357 | 5178 | 6264 | 7172 | 8605 |
| 2019 | 4350 | 5224 | 6384 | 7364 | 8919 |
| 2020 | 4343 | 5270 | 6505 | 7561 | 9245 |
| 2021 | 4336 | 5316 | 6629 | 7763 | 9583 |
| 2022 | 4329 | 5363 | 6756 | 7970 | 9933 |
| 2023 | 4322 | 5410 | 6885 | 8184 | 10297 |
| 2024 | 4316 | 5458 | 7016 | 8403 | 10673 |
| 2025 | 4309 | 5506 | 7150 | 8627 | 11063 |
| Growth 2000-25 | -0.46% | 0.52% | 1.58% | 2.34% | 3.37% |

**DSI Demand**

| Year | Low | Medlo | Medium | Medhi | High |
|---|---|---|---|---|---|
| | Revised Forecast | | | | |
| 2000 | | | 2477 | | |
| 2001 | | | 286 | | |
| 2002 | | | 412 | | |
| 2003 | | | 600 | | |
| 2004 | | | 642 | | |
| 2005 | 0 | 460 | 958 | 1200 | 1500 |
| 2006 | 0 | 460 | 958 | 1200 | 1500 |
| 2007 | 0 | 460 | 958 | 1200 | 1500 |
| 2008 | 0 | 460 | 958 | 1201 | 1500 |
| 2009 | 0 | 460 | 958 | 1201 | 1500 |
| 2010 | 0 | 460 | 958 | 1201 | 1500 |
| 2011 | 0 | 460 | 958 | 1201 | 1500 |
| 2012 | 0 | 460 | 958 | 1201 | 1500 |
| 2013 | 0 | 460 | 958 | 1201 | 1500 |
| 2014 | 0 | 460 | 958 | 1201 | 1500 |
| 2015 | 0 | 460 | 958 | 1201 | 1500 |
| 2016 | 0 | 460 | 958 | 1201 | 1500 |
| 2017 | 0 | 460 | 958 | 1201 | 1500 |
| 2018 | 0 | 460 | 958 | 1201 | 1500 |
| 2019 | 0 | 460 | 958 | 1201 | 1500 |
| 2020 | 0 | 460 | 958 | 1201 | 1500 |
| 2021 | 0 | 460 | 958 | 1201 | 1500 |
| 2022 | 0 | 460 | 958 | 1201 | 1500 |
| 2023 | 0 | 460 | 958 | 1201 | 1500 |
| 2024 | 0 | 460 | 958 | 1201 | 1500 |
| 2025 | 0 | 460 | 958 | 1201 | 1500 |
| Growth 2000-25 | | -6.5% | -3.7% | -2.9% | -2.0% |

**Irrigation Demand**

| Year | Low | Medlo | Medium | Medhi | High |
|---|---|---|---|---|---|
| | Revised Forecast | | | | |
| 2000 | | | 652 | | |
| 2001 | | | 690 | | |
| 2002 | | | 600 | | |
| 2003 | 593 | 598 | 600 | 606 | 610 |
| 2004 | 618 | 623 | 625 | 632 | 638 |
| 2005 | 621 | 626 | 629 | 636 | 643 |
| 2006 | 617 | 627 | 631 | 640 | 649 |
| 2007 | 613 | 628 | 634 | 645 | 656 |
| 2008 | 609 | 630 | 636 | 652 | 664 |
| 2009 | 606 | 632 | 639 | 658 | 672 |
| 2010 | 603 | 633 | 641 | 664 | 680 |
| 2011 | 600 | 635 | 644 | 670 | 687 |
| 2012 | 596 | 636 | 646 | 675 | 695 |
| 2013 | 592 | 636 | 649 | 679 | 701 |
| 2014 | 587 | 637 | 652 | 683 | 707 |
| 2015 | 582 | 636 | 654 | 687 | 713 |
| 2016 | 577 | 636 | 657 | 690 | 719 |
| 2017 | 572 | 636 | 659 | 694 | 726 |
| 2018 | 568 | 636 | 662 | 698 | 732 |
| 2019 | 563 | 636 | 665 | 702 | 738 |
| 2020 | 558 | 635 | 667 | 705 | 744 |
| 2021 | 554 | 635 | 670 | 709 | 751 |
| 2022 | 549 | 635 | 673 | 713 | 757 |
| 2023 | 544 | 635 | 675 | 717 | 763 |
| 2024 | 540 | 635 | 678 | 721 | 770 |
| 2025 | 535 | 635 | 681 | 725 | 777 |
| Growth 2000-25 | -0.79% | -0.11% | 0.17% | 0.42% | 0.70% |

**Other**

| Year | Low | Medlo | Medium | Medhi | High |
|---|---|---|---|---|---|
| | Revised Forecast | | | | |
| 2000 | | | 172 | | |
| 2001 | | | 158 | | |
| 2002 | | | 160 | | |
| 2003 | | | 160 | | |
| 2004 | | | 184 | | |
| 2005 | 185 | 185 | 185 | 185 | 185 |
| 2006 | 186 | 186 | 186 | 186 | 186 |
| 2007 | 188 | 188 | 187 | 188 | 188 |
| 2008 | 189 | 189 | 189 | 189 | 189 |
| 2009 | 190 | 190 | 190 | 190 | 190 |
| 2010 | 191 | 191 | 191 | 191 | 191 |
| 2011 | 193 | 193 | 193 | 193 | 193 |
| 2012 | 194 | 194 | 194 | 194 | 194 |
| 2013 | 195 | 195 | 195 | 195 | 195 |
| 2014 | 197 | 197 | 196 | 197 | 197 |
| 2015 | 198 | 198 | 198 | 198 | 198 |
| 2016 | 199 | 199 | 199 | 199 | 199 |
| 2017 | 201 | 201 | 200 | 201 | 201 |
| 2018 | 202 | 202 | 202 | 202 | 202 |
| 2019 | 203 | 203 | 203 | 203 | 203 |
| 2020 | 205 | 205 | 204 | 205 | 205 |
| 2021 | 206 | 206 | 206 | 206 | 206 |
| 2022 | 207 | 207 | 207 | 207 | 207 |
| 2023 | 209 | 209 | 208 | 209 | 209 |
| 2024 | 210 | 210 | 210 | 210 | 210 |
| 2025 | 211 | 211 | 211 | 211 | 211 |
| Growth 2000-25 | 0.83% | 0.83% | 0.82% | 0.83% | 0.83% |

# Fuel Price Forecasts

## INTRODUCTION

Fuel prices affect electricity planning in two primary ways. They influence electricity demand because oil and natural gas are substitute sources of energy for space and water heating, and other end-uses as well. Fuel prices also influence electricity supply and price because oil, coal, and natural gas are potential fuels for electricity generation. Natural gas, in particular, has become a cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines. This second effect is the primary use of the fuel price forecast for the Council's Fifth Power Plan.

Traditionally, the Council has developed very detailed forecasts of electricity demand using models that are driven by economic, fuel price, and technological assumptions. For a number of reasons, the Council has chosen to retain many elements of its long-term demand forecasts from the Fourth Power Plan, making modifications as needed to reflect significant changes that might affect the long-term trend of electricity use. Therefore, the fuel price assumptions did not directly drive the demand forecasts of this power plan.

The fuel price forecasts do affect the expected absolute and relative cost of alternative sources of electricity generation. Through their effects on generation costs, they also largely determine the future expected prices of electricity.

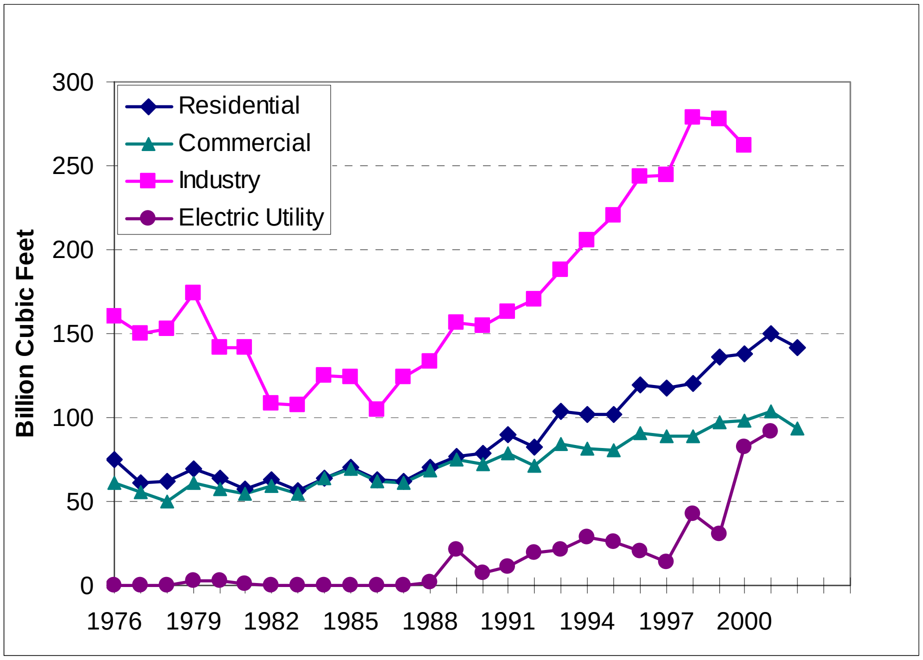
The forecast describes fuel price assumptions for three major sources of fossil fuels: natural gas, oil, and coal.

## NATURAL GAS

### Historical Consumption and Price

In 2000, the Pacific Northwest consumed 581 billion cubic feet (bcf) of natural gas. About 45 percent of this natural gas was used in the industrial sector, which included electricity generation by non-utility power plants. About a quarter of the natural gas use was in the residential sector and about 17 percent was in the commercial sector. In 2000, electric utilities consumed 83 bcf of natural gas, or about 14 percent of the regional total natural gas consumption. Utility natural gas consumption in 2000 was nearly three times the amount consumed in 1999, and it remained high in the early months of 2001. However, natural gas use for electricity generation was extraordinary in 2000 and early 2001 due to the electricity crisis in the West. Generating plants normally used only for extreme peak electricity needs were operated for much of the winter of 2000-2001. However, new gas-fired generation has been constructed and planned recently, which will increase normal levels of gas use for electricity generation.

The regional consumption of natural gas has grown rapidly over the last several years. Between 1986 and 2000 regional natural gas consumption grew 6.8 percent a year, more than doubling natural gas consumption over a 14-year period. Figure B-1 shows natural gas use by sector since 1976. After 1986, all sectors grew, but the industrial sector, which included independent electricity generation, accounted for nearly half of the increase in gas consumption and grew at a higher rate than residential and commercial use.  Increasing electric utility use of natural gas is also apparent in Figure B-1.




Source: Energy Information Administration and NPCC calculations.

**Figure B-1: Pacific Northwest Natural Gas Consumption**

The rapid growth in natural gas use since 1986 coincided with a period of ample natural gas supplies and attractive prices, coupled with strong economic growth in the region.  Figures 2a and 2b illustrate the Pacific Northwest natural gas prices and consumption since 1976 for the residential and industrial sectors.  High natural gas prices and a severe economic downturn in the early to mid-1980s kept natural gas consumption low.  However, following the deregulation of natural gas prices in the late 1980s, prices fell and demand began to grow rapidly.  Natural gas displaced oil and other industrial fuels for economic and environmental reasons during this time.  Higher electricity and oil prices for residential consumers combined with lower natural gas prices made natural gas a more attractive heating fuel for homes.

The most significant trend in natural gas markets has been the increasing use of natural gas for electricity generation.  This is a relatively recent trend, but attracts a lot of attention because of expectations of rapid growth in the future.  Figure B-1 shows some use of natural gas for electricity generation by electric utilities in the region since 1988.  It increased recently, but is still a relatively small amount of the total natural gas used in the region.  Non-utility electricity generators have used additional natural gas, but, until recently, the data did not allow it to be broken out from overall industrial sector natural gas use.  Given the level of concern about natural gas supplies, and the potential for a greatly increased use for electricity generation, it is worth understanding the current and potential role of natural gas in electricity generation.

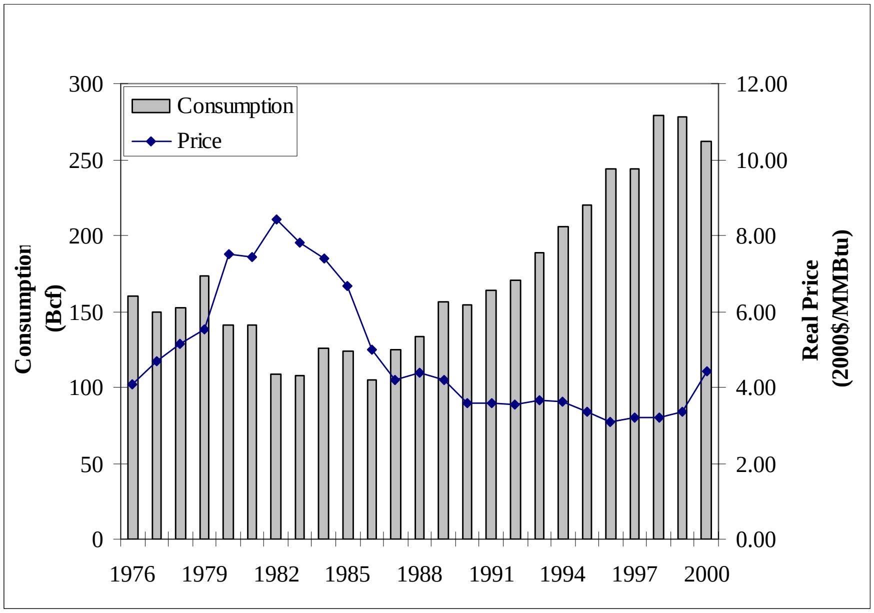



**Figure B-2a: Pacific Northwest Industrial Natural Gas Consumption and Price**

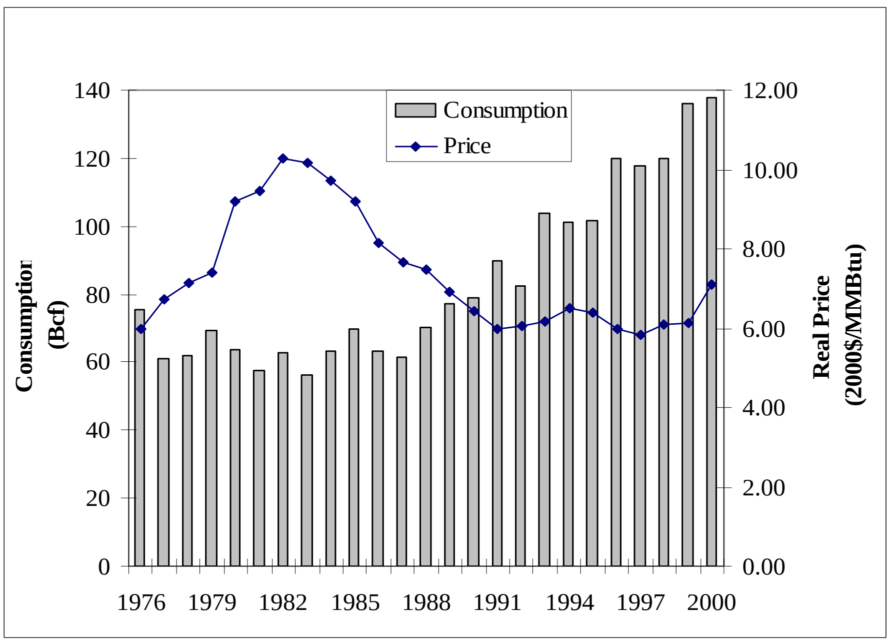



**Figure B-2b: Pacific Northwest Residential Natural Gas Consumption and Price**

Natural gas currently accounts for only 13 percent of the region's electricity generation capacity. In terms of average energy generated, the share is higher at 20 percent. That is because the hydroelectric capacity, which dominates the region's generating capacity, is limited in its annual production by the amount of water available so that its share of average generation is much lower than its capacity rating.

At the end of 1999 there were 38 plants that could generate electricity using natural gas with a combined generating capacity of 3,400 megawatts. Over half of this capacity (2,000 megawatts) had been built since 1990. Sixty percent of this capacity was owned by electric utilities and two-thirds of the capacity is located west of the Cascade Mountains. Many of these plants have the ability to burn other fuels such as wood waste, refinery gas, or oil.

If all of the plants using natural gas as their primary fuel were operating, they would be able to burn 668 million cubic feet of natural gas per day. Plants on the West side could burn as much as 476 million cubic feet per day. For perspective, this can be compared to the total capacity to deliver natural gas to the I-5 corridor on a peak day in 2004, which was estimated to be 3,760 million cubic feet per day.[1] If operated continuously for a year, the region's gas-fired generators in 1999 could burn 242 billion cubic feet of natural gas. This compares to an estimated 2001 total regional natural gas consumption of 670 billion cubic feet.

However, gas-fired generating plants in the region have not operated for a large part of the year, nor have they typically operated during peak natural gas demand events. This is partly due to the fact that in most years there is surplus hydroelectricity in the region. For example, utility-owned natural gas-fired generating plants in place at the end of 1999 had the capability to burn 141 billion cubic feet a year if operated at an 85 percent capacity factor on natural gas. However, as shown in Figure B-1, utilities only consumed 30 billion cubic feet of natural gas in 1999. In other words, utility-owned gas-fired generating facilities only consumed 20 percent of their capability in 1999. If the non-utility electricity generating capacity were assumed to operate at the same relative rate, they would have consumed only 14 billion cubic feet out of the 262 billion cubic feet of total industrial consumption in 1999.

In 2000, natural gas consumed for utility-owned electricity generation increased dramatically from 30 billion cubic feet in 1999 to 83 billion cubic feet. Non-utility generation from natural gas increased as well, but by a smaller percentage. This was not a result of additional gas-fired generation capacity being added in 2000. It was in response to the energy crisis of 2000 and the extremely high electricity prices that accompanied it. Existing gas-fired generation was operated far more intensively than normal because it was very profitable to do so.

Significant amounts of gas-fired generation have been added in the region since 2000. In 2001 an additional 1,176 megawatts of gas-fired generation capacity was put in service in the region, a 32 percent increase in gas-fired generation capacity. Another 1,330 megawatts was added in 2002, and an additional 1,560 megawatts in 2003. This new gas-fired generation will have a substantial impact on natural gas consumption in the region. According to the U.S. Energy Information Administration, the four Northwest states used 132 billion cubic feet of natural gas for electricity generation in 2003. This accounted for nearly a quarter of all natural gas consumption in the region.

In the past, most natural gas-fired electricity generation in the region has not operated on firm natural gas supplies and delivery. By buying interruptible service, the cost of natural gas could be reduced substantially. When interruptions came, during peak natural gas demand times, most of the plants, even if running, could switch to alternative fuels. Increasingly, new gas-fired generation plants are intended to operate at a high capacity factor and are more likely to use firm natural gas supplies and transportation.

The use of interruptible demand is a key feature in the ability of the natural gas industry to meet peak day demands for its product. Figure B-3 illustrates the role of interruptible consumers in meeting peak day natural gas demand.[2] The use of natural gas storage withdrawal and the injection

[1] 2004 Regional Resource Planning Study, Terasen Gas., July 2004.
[2] Based on Regional Resource Planning Study, BC Gas Utility Ltd., July 10, 2001.

of liquefied natural gas into pipelines are also used to meet peak requirements and help to increase the capacity utilization of natural gas pipelines.

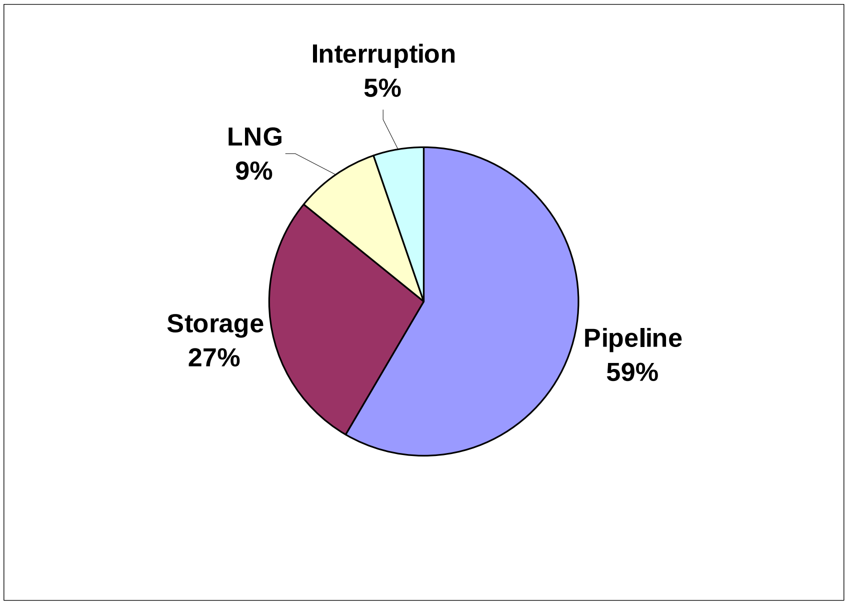



**Figure B-3: Contributions to Peak Day Natural Gas Supplies**

With a growing share of natural gas demand expected to be firm electricity generation, the share of interruptible demand may fall as a percent of total demand. This is likely to increase the value of other strategies for meeting peak gas demand such as storage and LNG injection. To the extent that increased gas-fired electricity generation turns out to add substantially to highly variable natural gas demand, the overall capacity factor of natural gas consumption would decrease. Lower capacity factors mean that, in general, the cost of natural gas on a per unit consumed basis could increase as fixed capacity costs are spread over a smaller amount of consumption per unit of capacity. This is not the only possibility, however. If many new gas-fired generating plants operate at a high capacity factor, or if they tend to operate more in the summer, they could have the opposite effect. They could partly offset the highly seasonal demand of the residential and commercial sectors, which peaks in the winter, and raise the overall capacity factor of the natural gas system.

In the summer of 2000, the use of natural gas-fired generation changed substantially on the West Coast. Poor hydroelectricity supplies and a growing electricity generating capacity shortage caused electricity prices to increase by a factor of 10 or more. The extremely high electricity prices made it attractive to burn gas for electricity generation; it was very profitable, and the electricity was badly needed to meet electricity demand. As a result, the use of natural gas on the West Coast for electricity generation increased dramatically. For example, it has been reported that California generators consumed 690 billion cubic feet of gas in 2000 compared to a normal consumption of 270 billion cubic feet.[3] Much of this increase in natural gas use began in the summer when natural gas use is typically lower and natural gas is injected into storage for use during the next winter heating season.

The problem created in natural gas markets may be some indication of the effects of the predicted growth of natural gas use for electricity generation in the future. In many regions, electricity use peaks in the summer. Growing use of natural gas for electricity generation has the potential to

[3] Natural Gas Week, Vol. 17, No. 18 (April 30,2001).

change the traditional seasonal patterns of natural gas storage and withdrawals. Less than expected storage injections in the summer and fall of 2000 led to concerns about natural gas shortages for the winter and pushed prices for natural gas to levels not seen since the early 1980s. This problem was especially severe in California, and combined with pipeline capacity strains, pushed prices in the West to several times historical levels.

However, the dramatic increase in the use of natural gas in existing generation plants in 2000 and early 2001 clearly had an exaggerated effect on natural gas markets and prices. Due to the sudden and severe shortage in electricity supplies and unprecedented electricity prices, the natural gas delivery system in the West was pushed far beyond normal operational patterns. Thus, the impacts on natural gas prices were more severe than should be expected from an orderly development of additional natural gas demands for electricity generation.

Although total natural gas consumption only recently returned to the levels of the early 1970s, substantial growth is now being projected due to growing plans for electricity generation. The U.S. Energy Information Administration is forecasting a growth in natural gas use of 1.4 percent per year for the next 20 years.[4] Residential and commercial natural gas use is projected to grow modestly at about 1 percent per year. Industrial sector use is projected to grow at 1.5 percent annually, but natural gas use for electricity generation is projected to grow by about 1.8 percent a year. The EIA forecasts would result in total U.S. natural gas consumption increasing from the current level of about 23 trillion cubic feet per year to 32 trillion cubic feet in 2025.

As an example of the possible effect of increased gas-fired electricity generation in the Pacific Northwest, complete reliance on natural gas-fired generation to meet a projected electricity demand growth of 1.0 percent a year for the next 20 years could add 217 billion cubic feet of natural gas consumption to the current 559 billion cubic feet per year. A modest 1.5 percent growth in other sectors' natural gas use could add another 147 billion cubic feet of new natural gas use in the region over the next 20 years. Meeting this demand would require continued expansion of natural gas supplies, pipeline capacity, and other elements of the natural gas delivery system, such as storage. Recent experience indicates that it will be increasingly difficult to expand North American natural gas production to meet increased demand. New sources of supply are likely to cost more and raise natural gas prices well above the levels enjoyed during the 1990s.

## Natural Gas Resources

Natural gas is created by natural processes and is widespread. Most current recovery methods attempt to exploit natural geologic formations that are able to trap natural gas in concentrated pockets. However, natural gas occurs in more dispersed forms as well. Eventually, it is likely to become possible to recover natural gas from some of these formations. Coal bed methane is a good example. Substantial amounts of natural gas are often associated with coal deposits. In the last several years methods have developed, with some government incentives, to extract the natural gas from coal formations, and this coal bed methane has made substantial contributions to the natural gas supplies in the Rocky Mountain area. It now accounts for about 7.5 percent of U.S. natural gas production.[5] Expansion of natural gas supplies increasingly will have to move into these less conventional areas, increasing costs. The amount of increase depends a great deal on technological developments in the exploration and recovery field.

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[4] U.S. Energy Information Administration, Annual Energy Outlook 2004.
[5] U.S. Geological Survey. "Coal-Bed Methane: Potential and Concerns." USGS Fact Sheet FS-123-00 (October 2000).

The availability of natural gas to meet growing demands is a key issue. Assessing natural gas resources is a confusing and difficult exercise. There is no absolute answer to the question of how much natural gas there is and how long it will last. Traditionally, the question has been approached on a North American basis, although Mexico has not traditionally played a large role. With the potential for increased use of liquefied natural gas (LNG) imports and exports, the market could become international, similar to current oil markets. Meanwhile, it may be instructive to look at North American natural gas resource estimates in a fairly traditional way.

There are two main categories of natural gas supplies. “Reserves” refers to natural gas that has been discovered and can be produced given the current technology and markets. Reserves are developed as needed by drilling wells in areas that are expected to hold natural gas producing potential. Reserves are often confused with the ultimate potential natural gas “resources,” which is the second category of natural gas supplies. Natural gas “resources” are more speculative than reserves, and resource estimates are more uncertain. They are based on assessment of geologic structures, not direct drilling results. Resource estimates are speculative estimates of natural gas that could be developed with known technology and at feasible costs. Reserves are more like the amount of natural gas resource that has been developed and is available to be produced within a relatively short period. Reserves should be thought of as an inventory of natural gas to be produced and marketed within a few years.

Natural gas reserves have decreased relative to consumption levels since the deregulation of natural gas supplies and changes in Canadian export policies in the 1980s. Some have taken this decline as an indication that we are running out of natural gas. In reality, it is a result of reducing inventory holding costs as a response to increased competition. It is similar to the new approaches to other kinds of inventory in the modern economy where businesses hold down inventory storage time and costs. In Canada, it was also influenced by elimination of a rule that required Canada to have a 20-year reserve for Canada’s internal natural gas demand before any natural gas could be exported. Canadian reserves are now closer to a 10-year supply.

So reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. During periods of low natural gas prices, consumption tends to increase and there is a reduced incentive to develop new reserves. Eventually, this leads to falling reserves and creates an upward pressure on prices such as the nation experienced recently. With the natural gas industry operating at narrower reserve margins, these cyclical patterns have become more severe and led to growing natural gas price volatility.

Another common error in assessing natural gas supplies is to assume that the estimates of ultimate natural gas resources are static. In reality, natural gas resource estimates have shown a tendency to increase over time as technology improves and new discoveries are made. To illustrate this point, note that in 1964 the Potential Gas Committee, which estimates natural gas resources, estimated potential natural gas resources to be 630 trillion cubic feet. By 1996, the nation had consumed more than 630 trillion cubic feet of natural gas. If the potential resource were a fixed limit, as many interpret it, we would have run out of natural gas by now. Instead the estimated potential remaining natural gas resource in 1996, at 1,038 trillion cubic feet excluding proved reserves, was actually higher than the estimate of what was remaining in 1964 in spite of over 30 years of continuing consumption. This does not mean that resource estimates will necessarily continue to increase in the future, but it illustrates the uncertain nature of natural gas resource estimates.

The Potential Gas Committee estimated that in 1996 the natural gas reserves and potential resources were 1,205 trillion cubic feet and noted that at then-current consumption rates, it would be a 63-year supply. A little different approach to estimating the years that the current estimated resource would last is to look at North American natural gas resource estimates and a predicted growing natural gas consumption to see how long those supplies would last. Table B-1 shows an estimate of remaining natural gas resources. Note that both of these calculations assume that potential natural gas resource estimates would not grow over time, as they have historically.

**Table B-1: Remaining Natural Gas Resources in North America (Trillion Cubic Feet)**

| | Already Produced | Remaining Reserves | Remaining Resources |
|---|---|---|---|
| | | | |
| Lower 48 States | 847 | 166 | 1,078-1,548 |
| Alaska | 0 | 0 | 237 |
| Canada | 103 | 51 | 559-630 |
| Mexico | 34 | 72 | 230-250 |
| | | | |
| Total | 984 | 289 | 2,104-2,665 |

Figure B-4 plots the growth in cumulative natural gas consumption into the future and identifies the years when the current resource estimate would be exhausted. The Mexican consumption of natural gas and its natural gas resources have been excluded from Figure B-4. U.S. and Canadian consumption is assumed to grow at 1.5 percent a year. Under these assumptions current estimated resources would last about 45 to 55 years. However, we should expect that the production of these resources will become increasingly difficult and expensive. If production rates cannot keep up with demand growth it will result in upward pressure on natural gas prices and increased volatility.

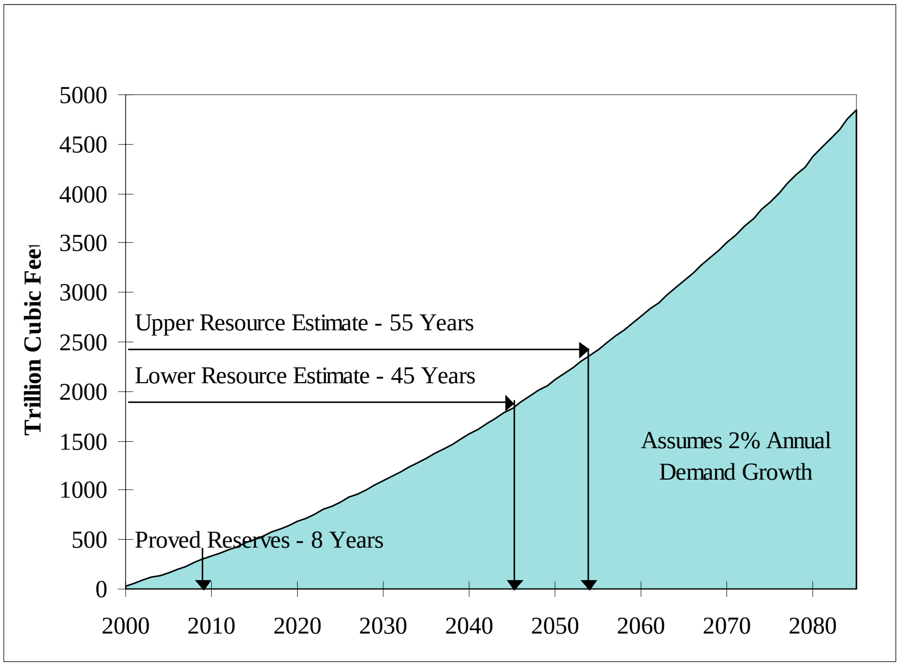



**Figure B-4: Cumulative Natural Gas Production and Resources**

However, based on past experience, the resource estimates are likely to increase over time in unpredictable ways. Some examples of potential changes will give some idea of what the future could hold in the longer term for natural gas resources. As in the case of oil, many natural gas resources lie outside of North America. Currently estimated conventional natural gas resources worldwide are 13,000 trillion cubic feet. As natural gas prices increase, the use of liquefied natural gas transportation will make these resources increasingly accessible to North America. In addition, natural gas occurs throughout nature in many forms. Besides coal bed methane, there are geopressurized brines and gas hydrates.[6] The ability to recover such sources is unknown at this point, but as new sources of gas are needed in the distant future, new technologies may facilitate some use of these resources. Gas hydrates, for example, are estimated to contain from 100,000 to 300,000,000 trillion cubic feet of natural gas resource.[7]

## Natural Gas Delivery

Another important consideration in natural gas supply and cost is the capacity to transport the gas from the wells to the points of consumption. This involves gathering the gas from wells, processing the gas to remove liquids and impurities, moving the gas over long distances on interstate pipelines, and finally, distribution to individual consumers' homes and businesses.

Currently, U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. In 2001, the United States imported 3.75 trillion cubic feet of natural gas from Canada; and 1.1 trillion cubic feet of that were imported through Sumas and Kingsgate on the region's border with Canada, with a substantial amount of that gas destined for California markets.

[6] U.S. Geological Survey. "Describing Petroleum Reservoirs of the Future." USGS Fact Sheet FS-020-97 (January 1997).
[7] U.S. Geological Survey. "Natural Gas Hydrates - Vast Resource, Uncertain Future." USGS Fact Sheet FS-021-01 (March 2001)

The sources of natural gas for the Pacific Northwest are the Western Canada Sedimentary Basin, in Alberta and Northeast British Columbia, and the U.S. Rocky Mountains. Two major interstate pipelines deliver natural gas into the Pacific Northwest region from Canada. Williams Northwest pipeline brings natural gas from British Columbia producing areas through Sumas, Washington where it receives gas from the Duke Westcoast pipeline in British Columbia. Williams Northwest pipeline also brings U.S. Rocky Mountain natural gas into the region from its other end. Thus, Williams Northwest is a bi-directional pipeline; it delivers gas from both ends toward the middle. The second interstate pipeline serving the region is the PG&E Gas Transmission Northwest (GTN) pipeline, which brings Alberta supplies through Kingsgate on the Idaho - British Columbia border. Much of the gas flowing on the GTN is destined for California. The GTN and Williams Northwest pipelines intersect near Stanfield, Oregon. The natural gas pipeline system serving the Pacific Northwest is illustrated in Figure B-5

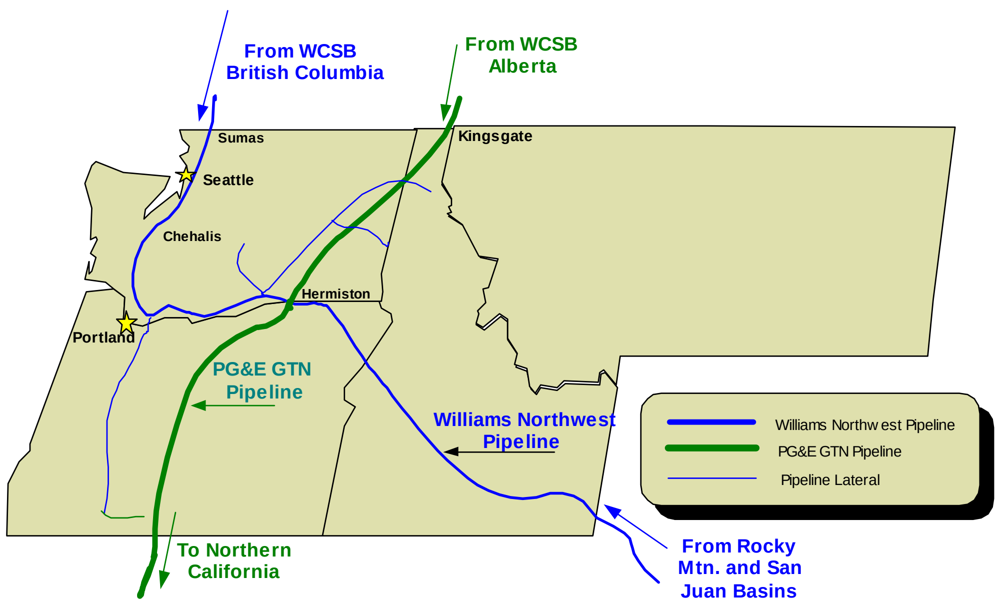



**Figure B-5: Natural Gas Pipelines Serving the Pacific Northwest**

The development of interstate pipeline capacity is based on the willingness of local distribution companies or other shippers of natural gas to subscribe to capacity additions. Historically, local gas distribution companies, the regulated utilities that serve core customers' natural gas demand, have owned much of the capacity on interstate pipelines. Because residential and commercial natural gas use varies seasonally and with temperatures, there is often pipeline capacity that is available for resale. Large industrial consumers and others who have some flexibility can acquire this capacity on a short term or capacity release basis. Interruptible consumers rely on this type of pipeline capacity, and it is typically available except on extremely cold winter days.

Growing natural gas demand results in pipeline capacity expansion as it is needed and as distributors or consumers are willing to pay for the capacity on an individual contractual basis. Interstate pipeline capacity is not expanded on a speculative basis based on someone's forecast of natural gas demand. Various expansions of pipeline capacity have been completed recently or are currently underway on both the Williams Northwest and the GTN systems, as well as on other pipelines throughout the West. Most of the entities committing to recent capacity expansions are electricity generators who are securing natural gas delivery capacity for proposed new electricity generating plants. Generating plant developers indicate that firm pipeline capacity is required in order to get financial backing for a new gas-fired combined cycle plant.

Over the long term, it should be expected that pipeline capacity will be expanded to deliver the necessary natural gas to regional consumers. In the short term, extremely unusual natural gas demands can place severe strain on pipeline delivery capacity, which can in turn cause serious natural gas price increases. This was the situation in the West in 2000-2001 when prices in California and the Northwest became disconnected from other U.S. prices.

## Forecast Methods

Natural gas prices, as well as oil and coal prices, are forecast using an Excel spreadsheet model. The model does not address the basic supply and demand issues that underlie energy prices. Instead assumptions are made about the basic commodity price trends at a national or international level based on analysis of past price trends and market behavior, forecasts of other organizations that specialize in such analyses, and the advice of the Council's Natural Gas Advisory Committee. The model then converts the commodity price assumptions into wholesale prices in the Pacific Northwest and other pricing points in the West, and then adds transportation and distribution costs to derive estimates of retail prices to various end-use sectors.

Because natural gas is the primary end-use competitor for electricity, and because it is the electricity generation fuel of choice at this time, natural gas prices are forecast in more detail than oil and coal prices. Residential and commercial sector retail natural gas prices are based on historical retail prices compared to wellhead prices. For historical years the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences between retail and wellhead natural gas prices can be projected from historical trends, other forecasting models, or judgment.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible natural gas consumers, whether industrial or electric utility, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple mark-up on. For these customers, the difference between wellhead and end-user prices is built from a set of transportation cost components and regional gas price differentials appropriate to the specific type of gas use.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and regional wellhead price differentials. The latter is necessary because the driving assumption is a national average wellhead gas price. Wellhead prices in British Columbia, Alberta, and the Rocky Mountains gas supply areas, the traditional sources of gas for the Pacific Northwest, have historically been lower than national averages. The fuel price model and assumptions are described in more detail in Appendix B1.

## Forecasts

### U.S. Wellhead Prices

There are a number of different indicators of U.S. natural gas commodity prices. The Council's analysis utilizes two of these measures. One is the U.S. wellhead price series published by the U.S. Energy Information Administration. The other is the Henry Hub cash market price. A link between U.S. wellhead prices and the Henry Hub cash price is estimated to relate the two series for the Council's analysis.

Figure B-6 shows the history of U.S. wellhead natural gas prices from 1970 to 2002. After the deregulation of wellhead natural gas prices around 1986, natural gas prices fell dramatically to the $2.00 per million Btu range in year 2000 dollars. Since then, until 2000, natural gas prices varied between $1.60 and $2.40 in year 2000 prices. In 2000, natural gas prices shot up, reaching a peak of over $9.00 by January 2001 as measured by spot prices at the Henry Hub in Louisiana. Although the 2000 price spike created expectations of significantly higher natural gas prices in the future, prices fell rapidly during 2001 and by September 2001 had returned to near their post-deregulation average of $2.15 in year 2000 prices. Many industry participants warned that the lower prices in the winter of 2001-02 were due to extremely warm temperatures, high natural gas storage inventories, and reduced demand as a result of higher prices and an economic slowdown and that there remained an underlying shortage of natural gas supplies.[8] Indeed, in the spring of 2002 prices firmed up to above $3.00 and prices in March 2003 averaged $8.00, with much higher excursions on a daily basis.

Wellhead natural gas prices averaged $4.81 in 2003 in year 2000 dollars. Prices have remained high in 2004 even with adequate storage levels and mild summer weather. Natural gas prices have been supported at a high level by high world oil prices. After 2005 prices are expected to begin moderating, but remain well above price levels of the 1990s. After 2005, prices decrease over several years as supply and demand adjust to the new conditions. By 2015 medium case prices remain $1.35 higher than the Fourth Plan forecast. The range of the forecast is wider in 2015 than in the Fourth Power Plan and it is significantly higher. The low is above the medium forecast of the Fourth Power Plan, and the high is $1.22 higher than the previous plan's high forecast.

Table B-2 shows actual U.S. wellhead prices for 1999 through 2003, annual forecasts for 2004 and 2005, and forecasts in five-year intervals after 2005. The last row of Table B-2 shows the average annual growth rate of real wellhead prices from 1999 to 2025. 1999 was chosen as the base year for growth rates because its price is close to the average price between 1986 and 1999. The projected growth in prices has already occurred, however, and from current prices the entire forecast range decreases. Figure B-7 shows the forecast range compared to historical prices.

[8] Natural Gas Advisory Committee, February 28, 2002

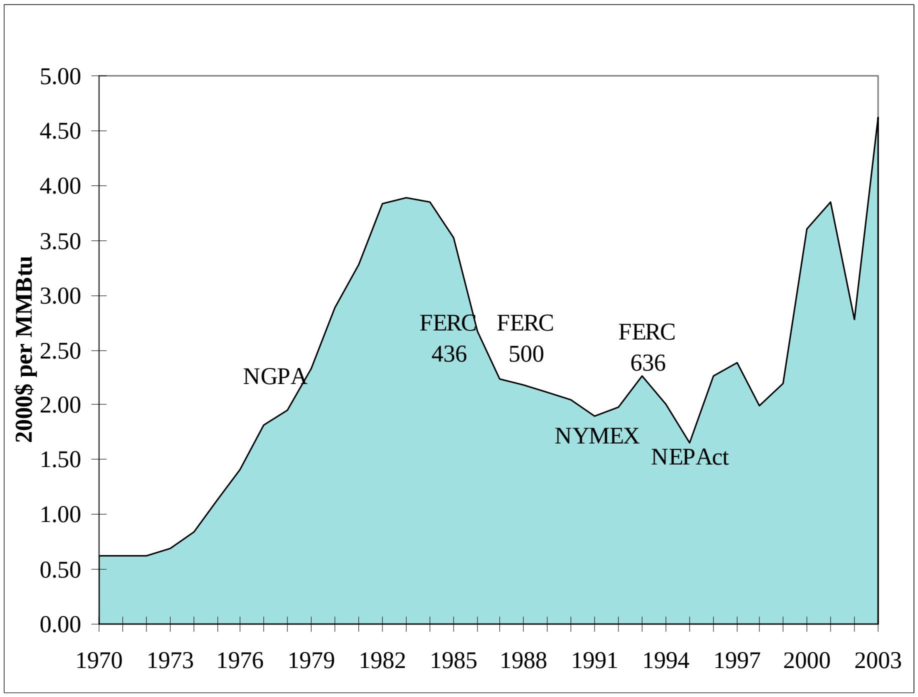



**Figure B-6: History U.S. Wellhead Natural Gas Prices**

**Table B-2: U.S. Wellhead Natural Gas Prices (2000$ per million Btu)**

| Year | Low | Med-low | Medium | Med-high | High |
|---|---|---|---|---|---|
| **1999** | | | 2.19 | | |
| **2000** | | | 3.60 | | |
| **2001** | | | 4.03 | | |
| **2002** | | | 2.80 | | |
| **2003** | | | 4.62 | | |
| **2004** | 4.75 | 5.20 | 5.45 | 5.60 | 5.80 |
| **2005** | 4.50 | 4.90 | 5.30 | 6.00 | 6.35 |
| | | | | | |
| **2010** | 3.00 | 3.30 | 4.00 | 4.50 | 5.00 |
| **2015** | 2.75 | 3.40 | 3.80 | 4.30 | 4.90 |
| **2020** | 2.90 | 3.50 | 3.90 | 4.35 | 5.00 |
| **2025** | 3.00 | 3.50 | 4.00 | 4.50 | 5.10 |
| **1999-2025 Growth Rate** | 1.22 | 1.82 | 2.34 | 2.81 | 3.31 |

The reader should not be lured into complacency by the smooth appearance of these forecasted prices. Future natural gas prices are not expected to follow a smooth pattern as reflected in the forecasts; they will be cyclically volatile, but the forecasts only reflect expected averages. There is, in fact, reason to expect continued volatility in natural gas prices because competition has narrowed reserve margins in the industry, making prices more vulnerable to changes in demand due to weather or other influences.[9] The consequences of price volatility, and ways to mitigate its impact, will be addressed in the part of the power plan that addresses risk and uncertainty in regional resource planning.

The low case forecast reflects a situation where improved technology allows expanded natural gas supplies to occur with relatively moderate real price increases. Sources of natural gas would continue to be primarily from traditional natural gas sources and coal bed methane. Low oil prices provide strong competition in the industrial boiler fuel market to help keep natural gas prices low. Continuing declines in coal prices, coupled with improved environmental controls, may moderate the growth in natural gas reliance for electricity generation.

The high case reflects a scenario with less successful conventional natural gas supply expansion. In the high case, higher prices would mean a growing role for frontier supply areas and liquefied natural gas imports. High prices of oil and slower progress on environmental mitigation of the effects of burning coal leave natural gas in a state of higher demand growth.

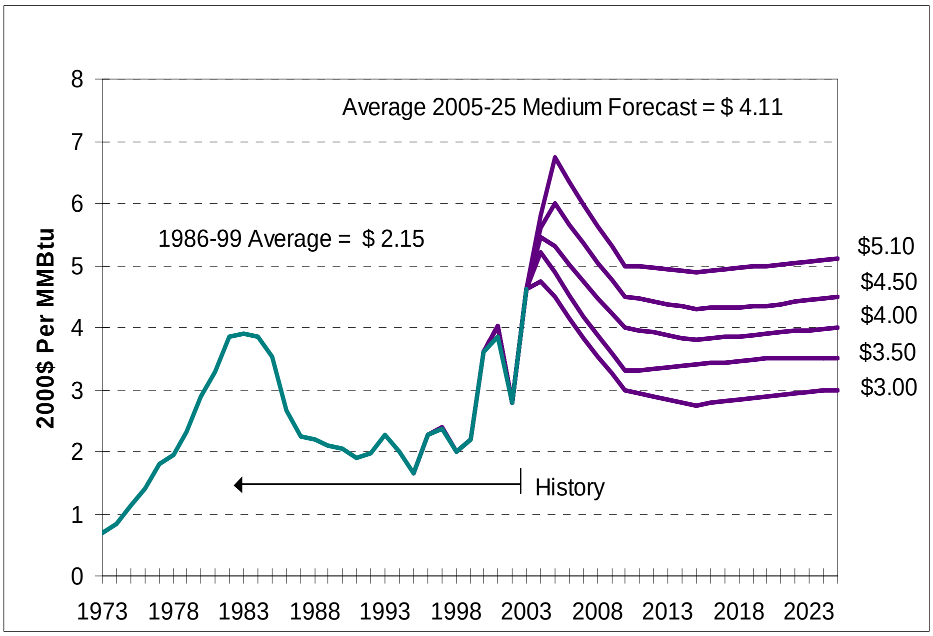
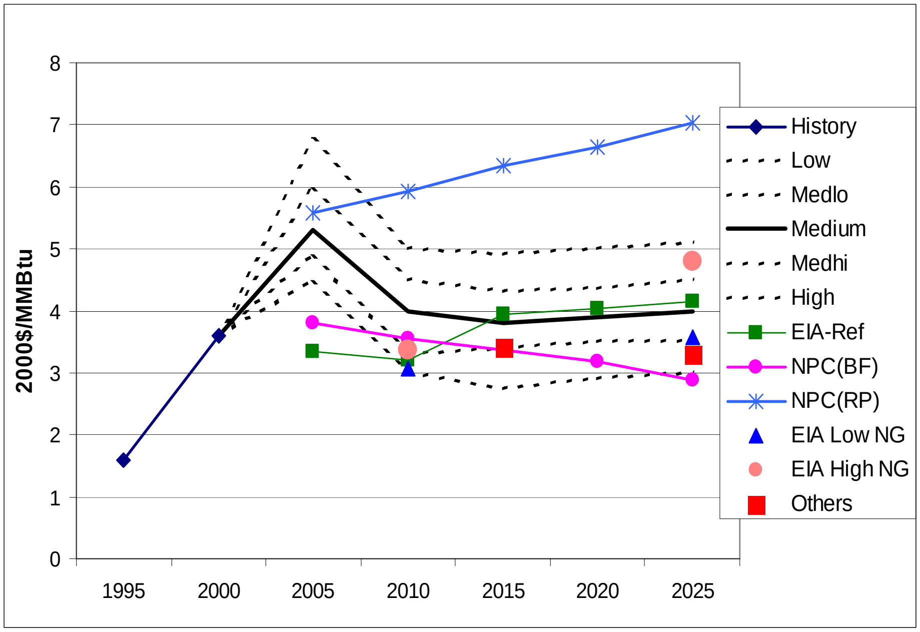



**Figure B-7: U.S. Wellhead Prices: History and Forecast**

Figure B-8 compares the Council's range of natural gas price forecasts to forecasts by some other organizations. A forecast in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2004 is similar to the Council's medium forecast. The main difference is that EIA's forecast is lower in 2005 and 2010. EIA also has a high and low natural gas price forecast based on alternative assumptions about technological advances in natural gas exploration and production. These cases differ little from the reference forecast in 2010, but in 2025 the EIA high case is between the Council's medium-high and high forecasts. EIA's low price case falls between the Council's low and medium-low forecasts. EIA reviewed several other forecasts that were available to them. The average of these other forecasts is shown as "others" in Figure B-8 and falls between the Council's medium-low and low forecasts. These forecasts were likely done in early to mid 2003

[9] Natural Gas Advisory Committee, February 29, 2002

and may have been revised upward since then. Another recent forecast was done by the National Petroleum Council (NPC), which completed a comprehensive analysis of natural gas supplies and markets. The NPC study shows two futures, one called the "reactive path" (RP), and the other called the "balanced future" (BF). The reactive path scenario illustrates the consequences of poor natural gas policies. It results in prices well above the Council's high case. The balanced future case results in natural gas prices that generally fall between the Council's medium-low and low cases.




Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2004*; National Petroleum Council. *Balancing Natural Gas Policy - Fueling the Demand of a Growing Economy*. September 25, 2003.

**Figure B-8: Comparison of Natural Gas Price Forecasts**

## Regional Natural Gas Price Differences

As noted above, for the AURORA® model analysis of electricity supplies and pricing, a forecast of Henry Hub cash market prices is used as the U.S. commodity price. Figure B-9 shows the difference between the Henry Hub price of natural gas and the U.S. wellhead price from 1989 through 2003. Excluding the most extreme values, the difference averaged $0.23 per million Btu in year 2000 dollars. To forecast Henry Hub prices, an equation was estimated from monthly inflation-adjusted historical prices that relates the Henry Hub price to the U.S. wellhead natural gas price.

AURORA® also requires information about future natural gas and other fuel prices for several pricing points throughout the Western United States. In the draft fuel price forecast in April 2003 the Council used fixed real dollar adjustments between Henry Hub and the other pricing points in the West. In the final power plan, these constant adjustments have been replaced with estimated equations similar to the one used to adjust wellhead prices to Henry Hub prices.[10]

Natural gas commodity prices in the Pacific Northwest have typically been lower than national prices. Between 1990 and 2003, Canadian natural gas prices delivered to the Washington border at Sumas averaged $.62 per million Btu less than the national market index at Henry Hub, Louisiana. Prices at the Canadian border at Kingsgate have averaged about $.08 lower than the Washington

[10] See Council staff paper on "Developing Basis Relationships Among Western Natural Gas Pricing Points".

border price at Sumas. As shown in Figure B-10, however, these regional price differences have been extremely volatile. Figure B-10 shows monthly regional price differences from Henry Hub to Sumas and Kingsgate from 1990 through 2003. Occasionally, regional natural gas prices have even been above Henry Hub prices. In December of 2000, they were dramatically so, reflecting regional pipeline constraints caused, in part, by the electricity crisis in the West and the sudden increase in the use of natural gas to generate electricity. The average differences exclude the extreme values in the winter of 1995-96 and 2000-01.

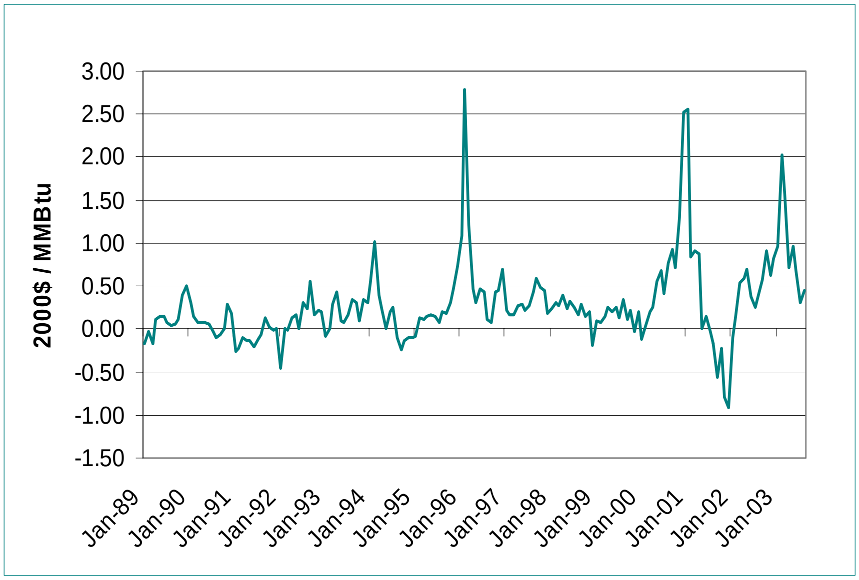



**Figure B-9: Difference Between Henry Hub and U.S. Wellhead Natural Gas Prices**

In addition to Canadian natural gas supplies through Sumas and Kingsgate, the Pacific Northwest receives natural gas supplies from the Rocky Mountain supply area on Williams Northwest Pipeline. Thus, Rocky Mountain natural gas supplies also play an important role in setting natural gas prices in the region. However, because of the direct competition among the various natural gas sources in the region, Rocky Mountain prices have generally tended to be similar to Canadian prices delivered into the region.

For purposes of forecasting regional natural gas prices in the eastern part of the region, a liquid pricing point in Alberta called the AECO-C hub is used as a focal point for regional natural gas prices. AECO-C prices have averaged $.81 per million Btu (2000$) less than Henry Hub prices since 1990. Prices in the western part of the region are estimated from Sumas prices at the Washington and British Columbia border. Sumas prices are estimated based on AECO and Rockies prices. The emerging natural gas pricing point in British Columbia is Station 2 in Northeastern British Columbia. However, there was insufficient historical data on Station 2 prices to estimate a relationship.

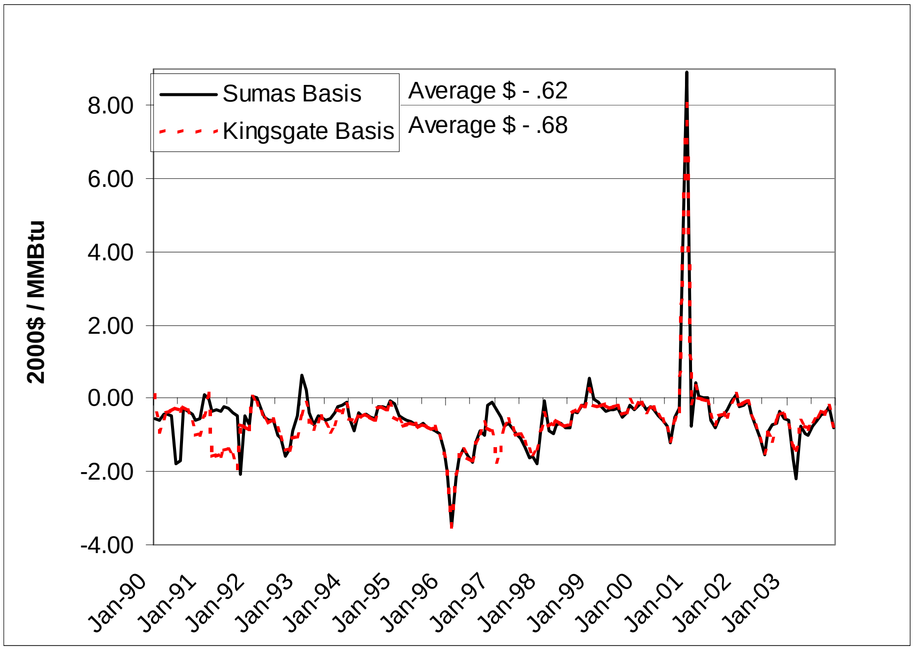



**Figure B-10: Canadian Gas Price Differences from Henry Hub**

### Retail Prices

The forecast prices paid by regional consumers of natural gas are based on the U.S. and Canadian commodity prices described in the previous section. The exact method depends on the consuming sector being considered and will be explained below.

Figure B-11 shows the regional retail natural gas price forecasts for end-use sectors compared to the U.S. wellhead price forecast for the medium case. The residential and commercial forecasts are based on historical differences between regional retail price and U.S. wellhead prices. Industrial price forecasts are a weighted average of three different price estimates; direct-purchase firm gas, direct-purchase interruptible gas, and local distribution company-served industrial customers. Direct-puchase gas is gas supply that is purchased directly by industrial customers instead of from local gas distribution companies (LDCs). The ability of industrial users to purchase natural gas directly in the market began with natural gas deregulation in the mid-1980s. The effect on industrial prices is apparent in Figure B-11, where the average industrial price moves toward the utility and wellhead price and away from the utility-served residential and commercial prices during the 1980s. The differences between U.S. wellhead and regional retail prices are discussed further below.

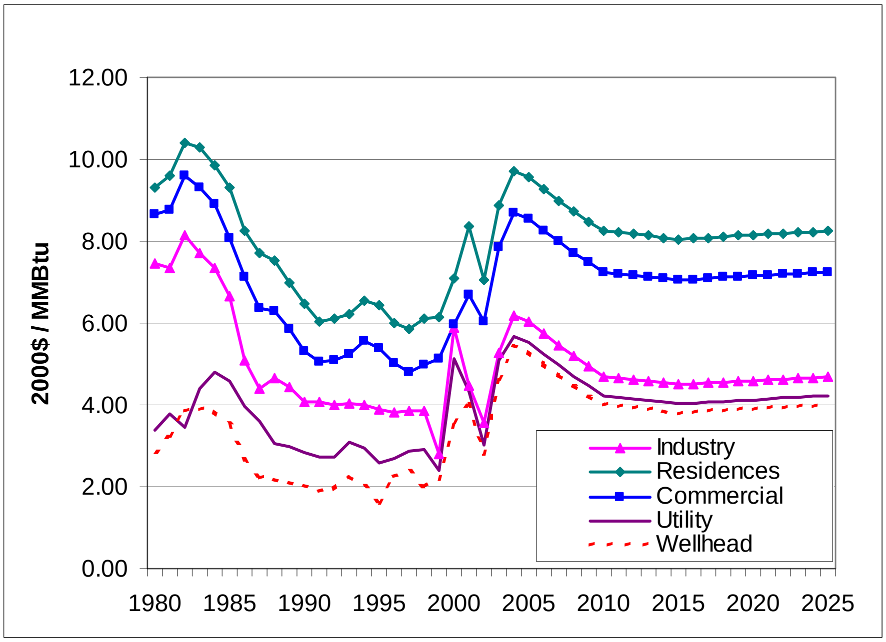



**Figure B-11: Retail and Wellhead Prices History and Medium Forecast**

Residential and commercial sector prices are based on observed differences from U.S. wellhead natural gas prices between 1989 and 2000. Figure B-12 shows that these differences declined during the 1980s. Since then, the differences have leveled off. The forecast assumes a $4.25 difference for residential and a $3.25 difference for commercial. These differences are held constant over the forecast period and across forecast cases.

As noted above, the industrial price shown in Figure B-11 is a blended price. The prices of the three components are derived in different ways. The LDC-provided prices are developed in the same way as residential and commercial prices. The forecast addition to U.S. wellhead prices to estimate LDC-provided retail prices starts at about $1.70, but unlike the residential and commercial adders, declines gradually over time. It does not, however, vary among forecast cases.

Directly purchased industrial natural gas prices are built from wellhead prices using estimates of the various components of gas supply and transportation costs. These components are described in detail in the Appendix B1, but Table B-3 shows, as an example, an estimate of regional industrial directly-purchased natural gas prices for 2010 in the medium case forecast. The example is a large, high-capacity-factor, industrial consumer. For electricity generators, natural gas and transportation costs are assumed to be different on the west and east side of the Cascade Mountains. There is no distinction applied to the industrial price forecasts; they are calculated using west side costs.

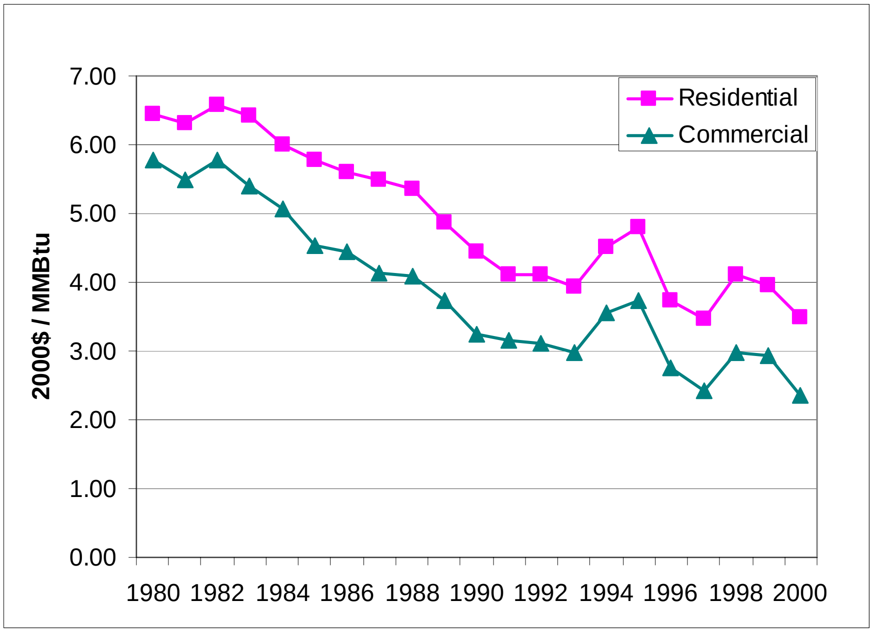



**Figure B-12: Historical Difference Between Regional Residential and Commercial Retail Natural Gas Prices and U.S. Wellhead Prices**

There is some disagreement whether a consumer who buys natural gas supplies on a firm basis would generally pay a premium for firm supplies. In this forecast, it is assumed that there is no premium. It is assumed that a large, high-capacity-factor industrial consumer would likely pay a negotiated rate for gas transportation by the local distribution utility and that there is no difference between firm or interruptible distribution service for such customers. This may only be the case for a customer with a potential to bypass the local distribution company, but the assumption about LDC transport cost only applies to industrial consumers and the forecast of industrial electricity demand in the Fifth Power Plan is not directly affected.

To combine the components into a blended price it is assumed that 30 percent of industrial natural gas consumption is purchased from the local distribution utility. The remaining 70 percent is purchased directly by industrial consumers. 90 percent of these direct purchases are assumed to be interruptible. It is assumed that a consumer that doesn't hold firm pipeline capacity will acquire released capacity or short-term firm capacity. In Figure B-11, the average difference between the U.S. wellhead price and the blended industrial users' price is small compared to the residential and commercial sectors. It is important to remember that the differences encompass a negative adjustment from Henry Hub commodity prices to AECO and Sumas, as described in the previous section.

Natural gas prices for electricity generators reflect the assumption that all electricity generators will buy their gas directly from suppliers rather than the local utility, and that generators will receive their gas supplies directly from interstate pipelines. Like industrial direct purchases, these purchases can be made on a firm or interruptible basis. In this forecast, it is assumed that all electric generator gas purchases are made on a firm transportation basis. Electric generator natural gas prices are calculated both in terms of average cost per million Btu, and in terms of fixed and variable natural gas costs. Again these assumptions are detailed in Appendix B1. Table B-4a shows an example of the calculation of natural gas costs for a new generating plant on the west side of the Cascade Mountains. Table B-4b shows the same derivation for a plant on the east side of the Cascade

Mountains. The examples are for the year 2010 in the medium forecast case. Appendix B3 shows annual natural gas price forecasts for the U.S. wellhead and retail prices for the residential, commercial, industrial and utility sectors for each forecast case. In addition, Appendix B2 shows similar information for electricity generators on the west and east side of the Cascade Mountains.

**Table B-3: Estimation of 2010 Industrial Firm and Interruptible Direct-Purchase Natural Gas Cost (2000$/MMBtu)**

| Price Components | Price Adjustments | Firm | Interruptible |
|---|---|---|---|
| Henry Hub Price | | $ 4.31 | 4.31 |
| Sumas Price | | 3.77 | 3.77 |
| In Kind Fuel Cost | + 1.74% | 3.84 | 3.84 |
| Firm Pipeline Capacity (Rolled-in) | + .28 | 4.12 | |
| Interruptible Pipeline Capacity | + .21 | | 4.05 |
| Pipeline Commodity Charge | $ + .04 | 4.16 | 4.09 |
| Firm Supply Premium | $ + 0.0 | 4.16 | |
| LDC Distribution Cost | + .20 | 4.36 | 4.29 |

**Table B-4a: Estimation of West Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)**

| Price Components | Price Adjustments | Firm | Interruptible |
|---|---|---|---|
| Henry-Hub Price | | $ 4.31 | $ 4.31 |
| Sumas Price | | 3.77 | 3.77 |
| In-Kind Fuel Charge | + 1.74% | 3.84 | 3.84 |
| Firm Pipeline Capacity (Incremental) | $ + .56 | 4.40 | |
| Interruptible Pipeline Capacity | $ + .21 | | 4.05 |
| Pipeline Commodity Charge | $ + .04 | 4.44 | 4.09 |
| Firm Supply Premium | $ + .00 | 4.44 | |

**Table B-4b: Estimation of East Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)**

| Price Components | Price Adjustments | Firm | Interruptible |
|---|---|---|---|
| Henry Hub Price | | $ 4.31 | $ 4.31 |
| AECO Price | | 3.66 | 3.66 |
| In-Kind Fuel Charge | + 2.8% | 3.76 | 3.76 |
| Firm Pipeline Capacity (Incremental) | $ + .45 | 4.21 | |
| Interruptible Pipeline Capacity | $ + .23 | | 3.99 |
| Pipeline Commodity Charge | $ + .01 | 4.22 | 4.00 |
| Firm Supply Premium | $ + .00 | 4.22 | |

Inputs to the AURORA® model are configured differently, but they are based on the same underlying U.S. wellhead price forecast. Adjustment from U.S. wellhead prices to AURORA® market area prices are described in Appendix B1.

### Treatment of Natural Gas Prices in the Portfolio Model

The discussion above described long-term trend forecasts for natural gas prices. These are important for the expected cost trends over the forecast horizon. However, the choice of generating and conservation resources also must consider volatility and risk inherent in natural gas prices. The Council's portfolio model assessed such price behavior and its affect on the cost and risk of alternative resource plans.

The portfolio model introduces additional kinds of variation into the analysis of natural gas prices to electricity generators in the region. Normal seasonal patterns are added to the annual trends, and random commodity price cycles are added with periods of extreme price variation. The result is an analysis of natural gas prices with much greater variation than the trend forecasts. Figure B-13 illustrates a sample of natural gas price futures evaluated in the portfolio model. The range of trend forecasts is shown as the shaded band. Clearly the portfolio analysis considers price excursions well outside the annual trend range, especially on the high price side.

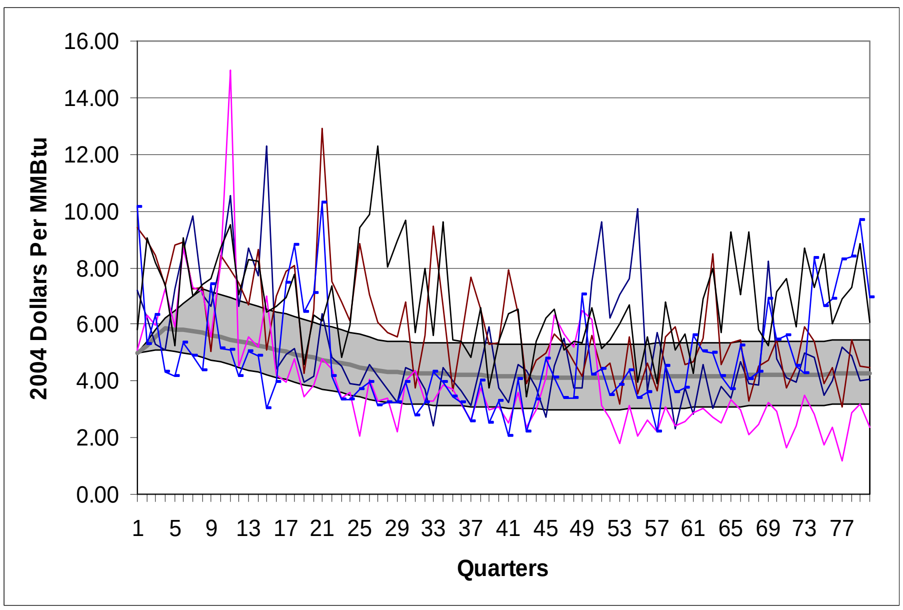



**Figure B-13: Illustration of Natural Gas Price Futures in the Portfolio Model**

## OIL

## Historical Consumption and Price

Oil products are playing a decreasing role in both electricity generation and in residential and commercial space heating in the Pacific Northwest. Figure B-14 shows that both distillate and residual oil consumption have generally been declining in all sectors since the mid-1970s.

To a large extent, declining oil consumption reflects growing natural gas use. Some increases in oil consumption are evident during the mid-1980s when natural gas prices were high. Substitution possibilities between natural gas and oil use in large industrial applications is a key feature of fuel markets. The substitution of oil for natural gas, for example, played an important role during 2001 in reducing high natural gas prices. In the Pacific Northwest, the displacement of industrial residual oil use is particularly dramatic as shown in Figure B-14.

In general, the price of oil products is determined by the world price of crude oil. Figure B-15 shows crude oil prices from 1978 to 2000 compared to refiner prices for residual oil and distillate oil. The differences are relatively stable with residual oil being priced lower than crude oil and distillate oil higher. On average, during this time period distillate oil was priced $1.00 per million Btu higher than crude oil. Residual oil was on average priced $.80 lower than crude oil. (Prices are in nominal dollars.) Retail prices of oil products follow very similar patterns, but at different levels.

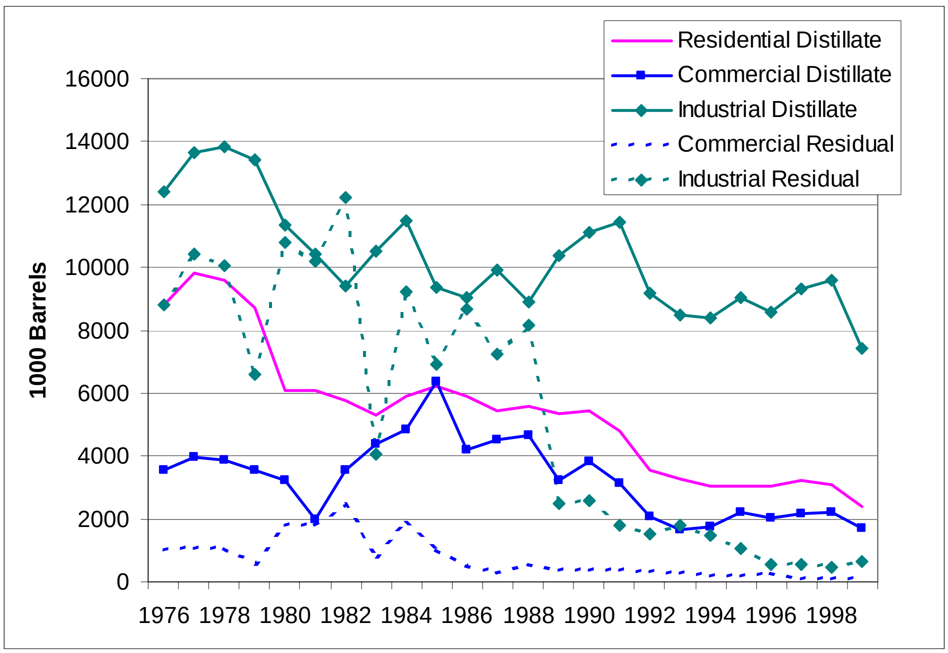



**Figure B-14: Historical Oil Consumption in the Pacific Northwest**

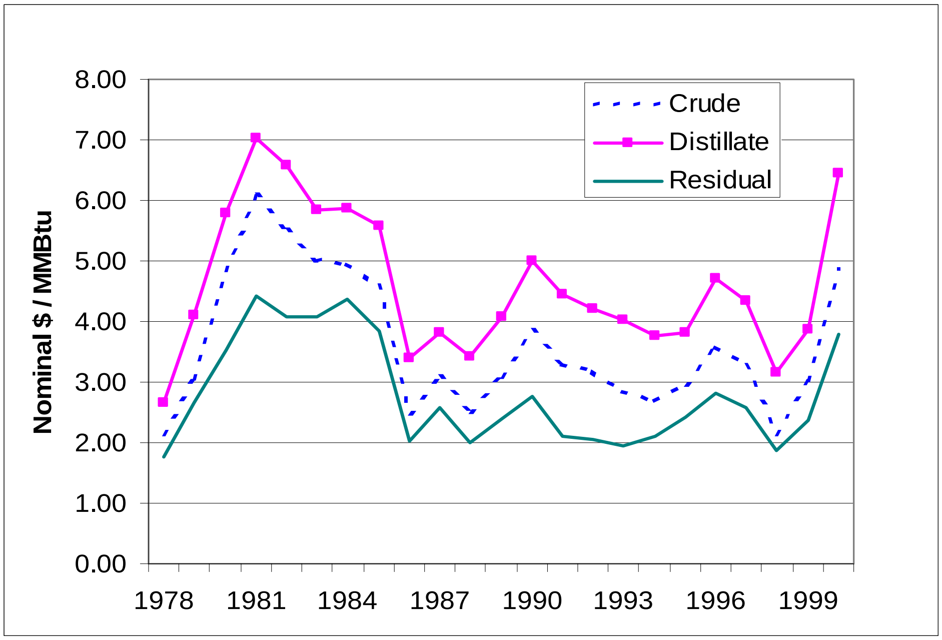



**Figure B-15: Comparison of Crude Oil and Refiner Product Prices**

## Methods

The forecasts of oil prices are based on assumptions about the future world price of crude oil. Refiner prices of distillate and residual oil are derived from formulas relating product prices to crude oil prices and refining costs. The formulas are based on a conceptual model of refinery costs and assume profit-maximizing decisions by refiners regarding the mix of distillate and residual oil production. Appendix B1 describes this model in more detail.

Although the refinery model is very simple, and the refining cost estimates and energy penalties have not been changed since the early days of the Council's planning, the ability of the equations to simulate historical prices remains good. Figures 16a and 16b show a comparison of predicted residual oil and distillate oil prices, respectively, based on actual world crude oil prices, to actual prices from 1978 to 2000. The equations appear to be predicting well, especially after the mid-1980s.

Forecasts of retail oil prices to end-use sectors are based on historical differences between the refiner price estimates for residual and distillate oil and actual retail prices. These mark-ups are assumed constant over time and across alternative forecast cases.

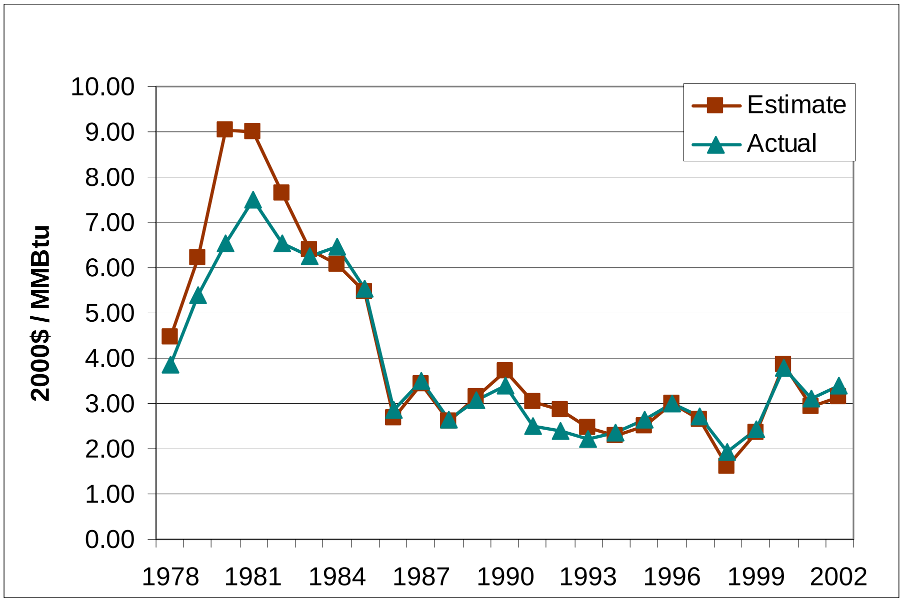



**Figure B-16a: Comparison of Forecast and Actual Residual Oil Prices**

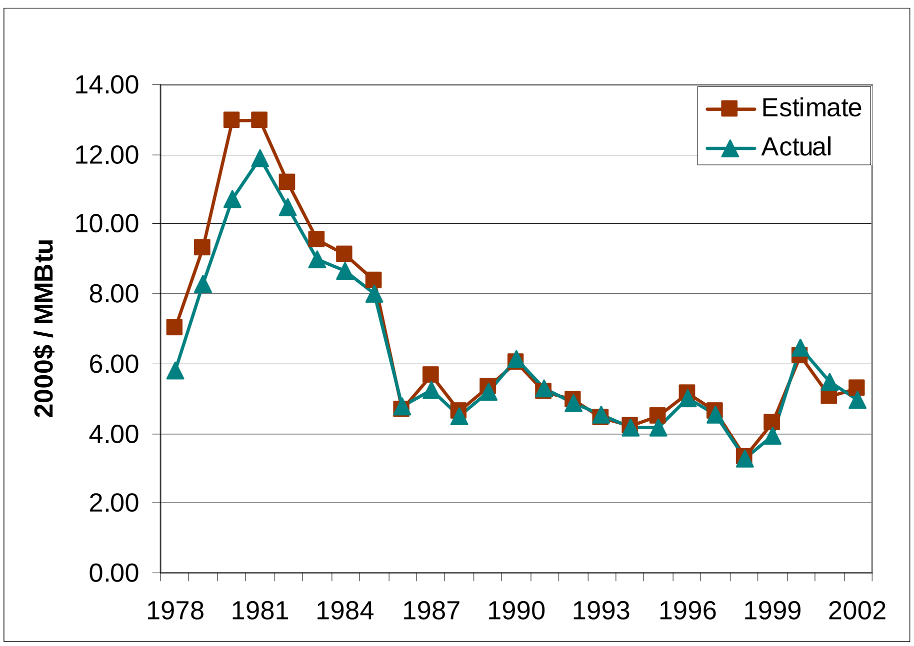



**Figure B-16b: Comparison of Forecast and Actual Distillate Oil Prices**

## World Crude Oil Price Forecast

The situation in world oil markets is very different from natural gas markets. Oil has much more of a world market than natural gas because it is easier to transport. The world's proved reserves of oil are about 1,000 billion barrels. World consumption of oil in 2000 was 27 billion barrels (based on BP and USGS data). Oil reserves are dominated by the Middle East, which has 65 percent of the world's proven reserves. The Middle East's reserves can be produced at low cost, but the middle eastern countries and their partners in the Organization of Petroleum Exporting Countries (OPEC) attempt to limit production so that world oil prices remain in the range of $22 to $28 per barrel. Proven oil reserves in the Middle East are 80 times the actual production rate in 2000. As a result, world oil prices are likely to depend on OPEC actions for the duration of the forecast period.

Although fluctuating world oil demand, Middle East conflicts, lapses in OPEC production discipline, and other world events will result in volatile oil prices over time, we have assumed a range of stable average prices in the forecast. Figure B-17 shows historical world oil prices and the five forecast cases.

Since the mid-1980s, world oil prices have averaged $21 a barrel in year 2000 prices. However, they varied from a low of $12.49 per barrel in 1998 to $27.69 in 2000. During 2001 and 2002, prices averaged in the low $20 range. Table B-5 shows historical world oil prices and forecasts for individual years between 2000 and 2005 and in five-year increments thereafter. A number of factors have caused an increase in world oil prices in 2003 and 2004. These include the Iraq situation, strikes in Venezuela, and a lower value of the U.S. dollar. In 2003 world oil prices averaged $26.23 and they have moved substantially higher in 2004, at times nearing $50. The forecasts assume that oil prices this high are a temporary condition. After 2010 the medium-low to medium-high forecast range settles to the $23 to $29 dollar range.

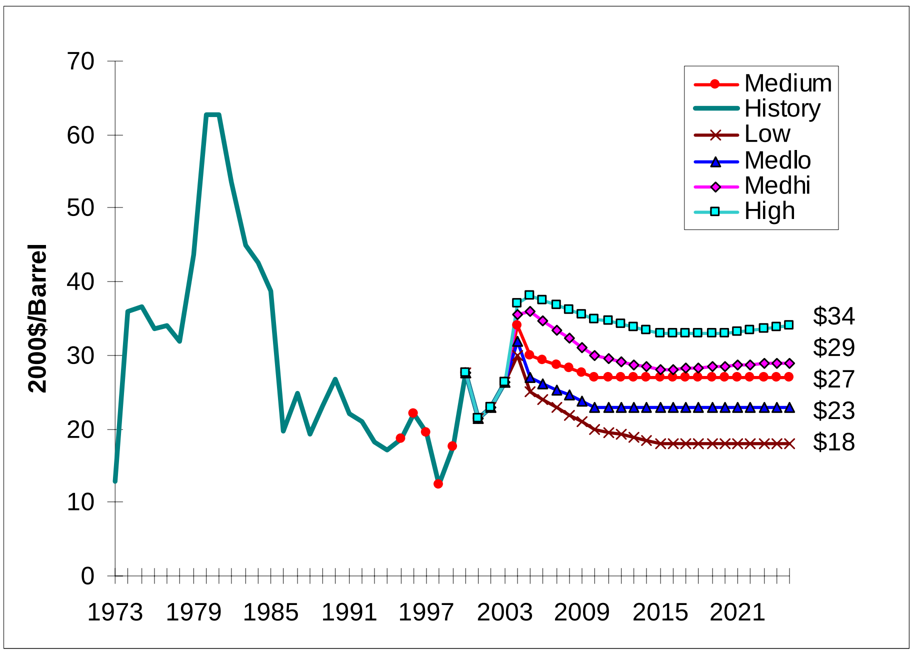



**Figure B-17: World Oil Price: History and Forecasts**

**Table B-5: World Oil Price Forecasts (2000$ per MMBtu)**

| | Low | Medium-Low | Medium | Medium-High | High |
|---|---|---|---|---|---|
| 2000 | | | **27.69** | | |
| 2001 | | | **21.52** | | |
| 2002 | | | **22.91** | | |
| 2003 | | | **26.23** | | |
| 2004 | **30.00** | **32.00** | **34.00** | **35.50** | **37.00** |
| 2005 | **25.00** | **27.00** | **30.00** | **36.00** | **38.00** |
| | | | | | |
| 2010 | **20.00** | **23.00** | **27.00** | **30.00** | **35.00** |
| 2015 | **18.00** | **23.00** | **27.00** | **28.00** | **33.00** |
| 2020 | **18.00** | **23.00** | **27.00** | **28.50** | **33.00** |
| 2025 | **18.00** | **23.00** | **27.00** | **29.00** | **34.00** |

The assumptions about future oil prices are based on observation and analysis of historical prices and on comparisons among forecasts made by other organizations that put substantial resources into the analysis of future oil price trends. Figure B-18 shows historical world oil prices for 1990, 1995 and 2000 compared to the forecast range and a range of other forecasts. The U.S. Energy Information Administration (EIA) is the source of the summary of other forecasts.[11] Figure B-18 shows EIA's forecast range and the average of 8 other forecasts that EIA compared to their own forecast. EIA's reference case forecast falls between our medium-low and medium cases after 2005. EIA's range is also consistent with our low to high range after 2005. The average of the 8 other forecasts falls between our low and medium-low forecasts. These other forecast did were done during 2003 and did not have the advantage of knowing about recent oil prices, so their 2005 forecasts are well below the Council's in the near term. Appendix B4 contains tables of annual forecasts for world oil prices and retail sector oil prices for each forecast case.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2004.

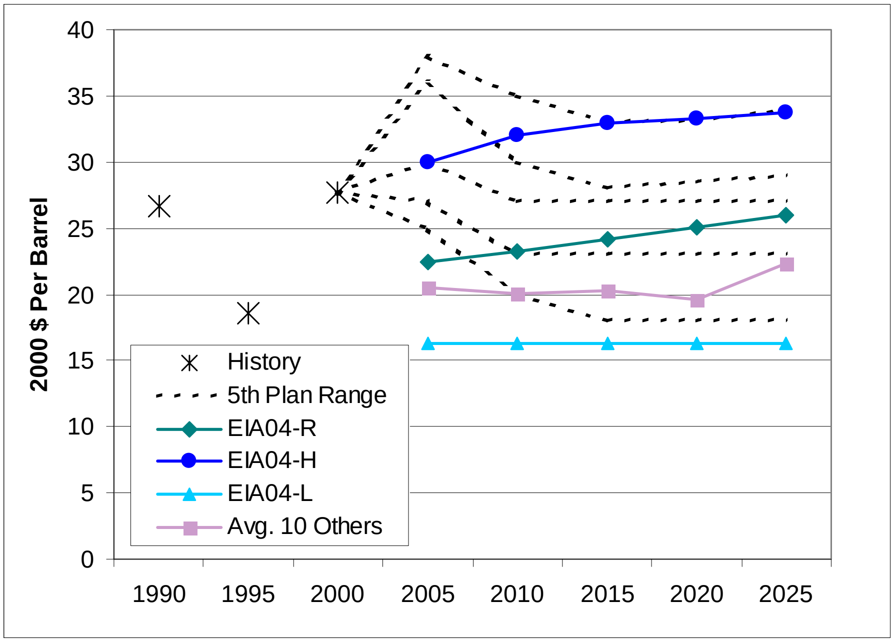



**Figure B-18: Comparison to Other World Oil Price Forecasts**

## Consumer Prices

Using the methods described earlier, world oil price forecasts are converted to refiner prices of residual oil and distillate oil. Figure B-19 shows the forecast relationship among the prices of these refiner products for the medium case. A set of mark-ups is used to derive forecasts of retail prices for various products to end use sectors. These retail mark-ups, shown in Table B-6, are generally assumed constant over time and across forecast cases. The mark-ups are based on historical average price relationships during the 1980s and 1990s. Appendix B5 contains detailed tables for the oil price forecast.

**Table B-6: Retail Mark-up Assumptions for Oil Products and Sectors**

| | |
|---|---|
| INDUSTRIAL SECTOR | |
| Residual Oil Over Refinery | $ .24 |
| Distillate Oil Over Refinery | $ 1.00 |
| UTILITY SECTOR | |
| Residual Oil Over Refinery | $ .24 |
| Distillate Oil Over Refinery | $ .46 |
| COMMERCIAL SECTOR | |
| Residual Oil Over Industrial | $ .05 |
| Distillate Oil Over Industrial | $ -.42 |
| RESIDENTIAL SECTOR | |
| Distillate Oil Over Industrial | $ 1.98 |

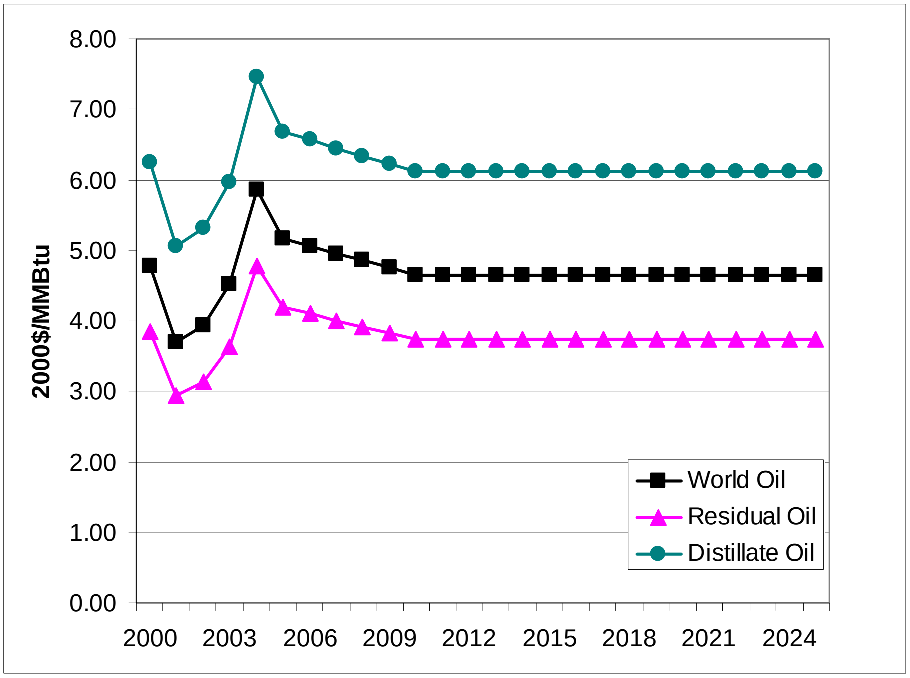



**Figure B-19: Refiner Prices of Residual and Distillate Oil Compared to World Crude Oil Price (Medium Case)**

## COAL PRICE FORECASTS

Coal prices play little role in determining regional electricity demand. There are not many end uses where coal and electricity substitute for one another and coal consumption is relatively minor in the Pacific Northwest in any case. Coal as a percent of total industrial fuel purchases in the region in 1999 was 0.7 percent compared to 6.1 percent for the U.S. as a whole. Coal is also a relatively minor electricity generation fuel in the region compared to the U.S. In 1999, coal accounted for 14 percent of regional utility fuel purchases compared to 55 percent for the nation. Only Montana had a coal generation share similar to the US for electricity generation.

Nevertheless, coal may be an important alternative as an electricity generation fuel in the future. The trade-off is that while coal is a plentiful and relatively inexpensive domestic energy source, it also has substantial environmental impacts both during extraction and burning. Thus its future may depend on technological progress in emissions controls and policies with regard to air quality and global warming.

Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[12] One measure is "demonstrated reserve base," which measures coal more likely to be mined based on seam thickness and depth. EIA estimates that the 1997 U.S. demonstrated reserve base of coal is 508 billion short tons. Only 275 billion short tons of these resources are considered "recoverable" due to inaccessibility or losses in the mining process. This is still a large supply of coal relative to the current production of about 1 billion short tons a year.

About half of the demonstrated reserve base of coal, 240 billion short tons, is located in the West. Western coal production has been growing due to several advantages it has over Appalachian and

[12] U.S. Energy Information Administration, U.S. Coal Reserves: 1997 Update, February 1999.

interior deposits. Western coal is cheaper to mine due to its relatively shallow depths and thick seams. More important, Western coal is lower in sulfur content. Use of low-sulfur coal supplies has been an attractive way to help utilities meet increased restrictions on $SO_2$ emissions under the 1990 Clean Air Act Amendments that took effect on January 1, 2000. The other characteristic that distinguishes most Western coal from Eastern and interior supplies is its Btu content. Western coal is predominately sub-bituminous coal with an average heat content of about 17 million Btu's per short ton. In contrast, Appalachian and interior coal tends to be predominately higher grade bituminous coal with heat rates averaging about 24 million Btu per short ton.

Western coal production in 2000 was 510.7 million short tons. Two-thirds of that production came from Wyoming, 338.9 million short tons. The second largest state producer was Montana at 38.4 million tons. Colorado, New Mexico, North Dakota and Utah produced between 26 and 31 million short tons each, and Arizona produced about 13 million short tons.

Productivity increases have been rapid, especially in Western coalmines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by nearly 6 percent per year between 1985 and 2000. Expiring higher priced long-term contracts have also contributed to declining coal prices.

The price of delivered coal is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from mine-mouth costs due to long-term coal supply contracts. Figure B-20 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 1999.[13] Coal prices increased during the late 1970s with other energy prices, but since the early 1980s have declined steadily. On average, regional industrial coal prices decreased at an annual rate of 3.2 percent between 1980 and 1999. Regional utility coal prices have followed a similar pattern of decline, although utility prices were delayed a few years in following industrial prices downward. This may have been due to longer-term coal contracts for the coal-fired generation plants in the region.

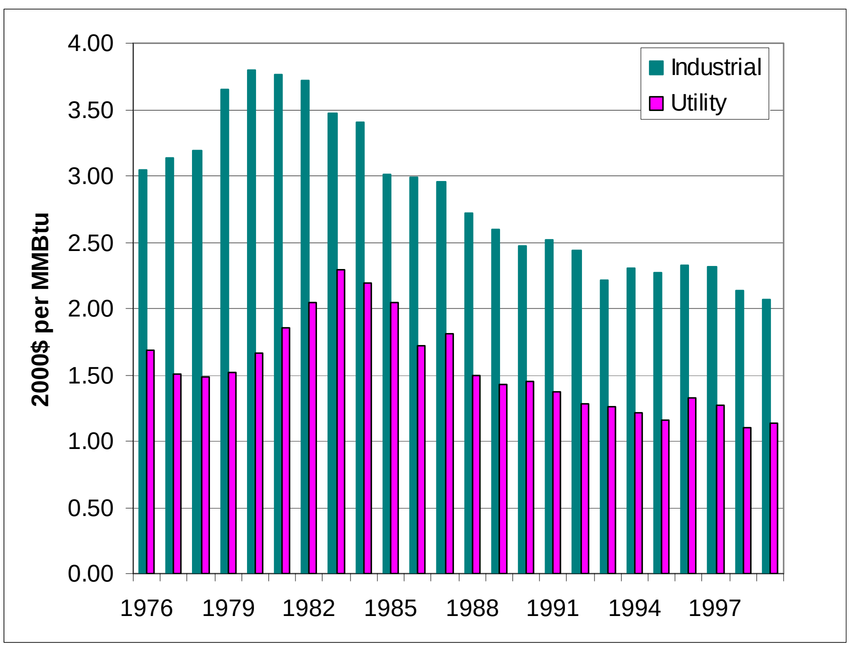



**Figure B-20: Pacific Northwest Industrial and Utility Historical Coal Price Trends**

[13] U.S. Energy Information Administration

Forecasts of coal prices rely on a very simple method. Different constant rates of price change for Western mine-mouth coal prices are assumed for the five forecast cases. The assumptions are shown in Table B-7. In all cases, the rapid declines in coal prices over the last 20 years are assumed to end. The medium case assumes stable prices. The lower cases assume slight decreases, and the higher cases slight increases. The EIA forecast of Western Coal prices grows at about the same rate as the Council's medium-high forecast.

**Table B-7: Assumed Western Mine-mouth Coal Price Growth Rates**

| Forecast Case | Average Annual Rate of Growth |
|---|---|
| | |
| Low | - 0.8 % |
| Medium Low | - 0.5 % |
| Medium | 0.0 % |
| Medium High | + 0.5 % |
| High | + 0.9 % |

Delivered prices to Pacific Northwest industries and utilities are estimated by applying fixed mark-ups from Western mine-mouth prices to delivered prices. Because transportation costs are significant for coal, states that are farther away from the mines tend to have significantly higher delivered coal costs. Montana and Wyoming delivered costs, however, can be quite close to the mine-mouth price. Some coal-fired electricity generating plants are located at the mine and have little, if any, transportation cost. In more distant states, like Washington, the delivered cost can be more than 3 times the mine-mouth price. Table B-8 shows the additions to Western mine-mouth coal prices for the states in the West and the 2010 medium forecast of coal prices that result. Appendix B5 contains annual forecasts of coal prices for each of the forecast cases.

**Table B-8: Derivation of State Electricity Generator Coal Prices, 2010 Medium Forecast (2000$ per Million Btu)**

| | Mark-up from Mine | Price Forecast |
|---|---|---|
| Western Mine-mouth | | $ 0.51 |
| Washington | $ + .99 | 1.50 |
| Oregon | + .53 | 1.05 |
| Idaho | + .45 | .96 |
| Montana | + .01 | .52 |
| Utah | + .62 | 1.13 |
| Wyoming | + .19 | .70 |
| Colorado | + .47 | .98 |
| New Mexico | + .86 | 1.37 |
| Arizona | + .82 | 1.33 |
| Nevada | +.88 | 1.39 |

# APPENDIX B1 - FUEL PRICE FORECASTING MODEL

## Introduction

This Appendix describes the fuel price forecasting model that was used for the Council's Fifth Power Plan. The model consists of several worksheets linked together in an EXCEL "workbook."

The model includes forecasts of natural gas, oil and coal prices. Retail fuel prices for the various demand sectors are derived from the forecasts of basic energy commodity prices; that is, the world price of oil, the average wellhead price of natural gas, and Western mine-mouth coal prices. These energy prices are forecast by several organizations that specialize in energy market forecasting. Thus, basic energy price trends can be compared to a variety of forecasts which helps define a range of possible futures based on much more detailed modeling and analysis than the Council has the resources to accomplish alone. The prices of oil, natural gas, and coal, are not explicitly linked to one another. Rather, the relationships should be considered by the analyst in developing fuel price scenarios.

Retail prices are estimated by adding cost components to the basic energy commodity prices. Where possible these additional costs, or mark-ups, are based on historical relationships among energy costs to various sectors. Thus, the basic driving forces in the fuel price model are world oil price forecasts, wellhead natural gas price forecasts, coal price growth rates, and mark-ups to retail prices in various end-use sectors. In the case of natural gas, prices at various trading points in the West are estimated using equations describing the basis relationships among various locations.

The degree of detail devoted to each fuel depends on its relative importance to electricity planning. For example, natural gas is a very important determinant of both electricity demand and the cost of electricity generation from gas-fired plants. As a result, the natural gas forecasting approach is significantly more detailed than oil or coal. Oil plays a smaller role in competition with electricity use and in electricity generation and receives less attention. Coal plays little role in determining electricity demand and is treated very briefly in the model using assumed annual growth rates.

## Model Components

Historical retail data for each fuel are kept on separate Excel files. These spreadsheets contain historical retail price data by state and consuming sector from the "State Energy Price and Expenditure Report" compiled by the U.S. Energy Information Administration (EIA). In addition, they contain consumption data from the "State Energy Data Report," also published by EIA. The spreadsheets convert the prices to real 2000 dollars and calculate consumption weighted average regional prices for each end-use sector. In addition, wholesale market price data is maintained in separate files.

Forecasts of world oil prices and natural gas wellhead prices are developed in the WOPFC and NGFC tabs, respectively, in the FUELMOD04 Excel Workbook. They take historical data, consistent with the historical fuel price worksheets described in the previous paragraph, and merge it with forecasts in five-year intervals. The worksheet interpolates between the five-year forecasts to get annual values. These tabs also contain previous Council forecasts and forecasts by other organizations for comparison purposes.

MAIN contains the forecasts of basic oil and gas commodity prices calculated in WOPFC and NGFC for a specific forecast case and any other scenario dependent assumptions and parameters. It also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices. Wellhead gas prices feed into the gas price model and world oil prices feed into the oil price model. MAIN contains the scenario controls and variables for the entire model. The varying scenario assumptions and their cell locations are as follows:

| | |
|---|---|
| Scenario Name | B2 |
| Wellhead Natural Gas Price | B30:B54 |
| World Oil Price | C30:C54 |
| Real Growth Rate of Incremental Pipeline Costs | D60 |
| Coal Price Growth Rate | D61 |
| Firm Natural Gas Supply Share | D62 |

The separate tabs in FUELMOD04 are described at the end of this appendix in a section entitled Model Components, which is a printout of the first tab (“DOC”) in the model. The model structure is described in more detail below.

## Natural Gas Model

The natural gas price-forecasting component is far more detailed than the oil or coal components. This is not only because natural gas is currently the strongest competitor to electricity, but also because of the lack of reliable historical price information for large industrial and electric utility gas purchases.

The natural gas price forecasts begin with a forecast of average U.S. wellhead prices. These are used to estimate prices at other trading points throughout the West in the tab called NG West. In addition, state utility natural gas prices are estimated in NG West. Where supported by historical data, regression equations were estimated that relate these various natural gas prices. For a description of the data and estimations see Council staff paper “Developing Basis Relationships Among Western Natural Gas Pricing Points”.

There are three separate worksheets for Pacific Northwest natural gas price forecasts by sector: INDUST, which contains industrial sector forecasts; NWUTIL which contains electricity generator forecasts; RES_COM which contains residential and commercial forecasts. A separate worksheet, COMPONENTS, supports the industrial and electricity generator price forecasts by accounting for the various components of cost that are incurred between the wellhead and the end-user. The worksheet GASSUM is simply a report that summarizes the natural gas price forecasts. The tabs 00$NWUtil and AURORA report fixed and variable cost of natural gas for electricity generators.

Residential and commercial sector gas prices are based on historical regional retail prices compared to U.S. wellhead prices. For historical years, the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences, or mark-ups, can be projected from historical trends, other forecasting models, or judgment.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible customers, whether industrial or electricity generators, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple mark-up on. For these customers, the difference between wellhead and end user prices is built up from a set of transportation cost components appropriate to the specific type of gas use. These components are developed in the worksheet COMPONENTS.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and firm gas supply premiums, if any. These adjustments are applied to AECO prices for the regional eastside prices, and to Sumas for the regional westside prices. Three types of pipeline capacity costs are used; incremental firm, rolled-in firm, and interruptible or capacity release. New electricity generation plants are assumed to require incremental firm pipeline capacity. The part of pipeline capacity costs that could not likely be recovered from the capacity release market becomes a part of fixed fuel costs.

Tables B1-1 and B1-2 show the various transportation components, their column location in the COMPONENTS worksheet, and the current value or range of values in the model. Table B1-1 applies to a large natural gas consumer on the west side of the Cascades and Table B1-2 applies to the same kind of consumer on the east side.

**Table B1-1: West-Side Cost Components for Calculating Delivered Natural Gas Prices.**

| Cost Component | Components Column | Constant Costs (2000$/MMBtu) | Scenario Variant | | | | |
|---|---|---|---|---|---|---|---|
| | | | L | ML | M | MH | H |
| U.S. Wellhead Price | B | | | | | | |
| Henry Hub Price | C | | | | | | |
| Sumas Price * | Q | | | | | | |
| | | | | | | | |
| Pipeline Capacity Costs | | | | | | | |
| Firm Rolled-In | E | + .28 | | | | | |
| Firm Incremental | G | +.55 in 2006 + growth | -0.1 | 0.1 | 0.3 | 0.5 | 0.7 |
| Released Capacity Cost * | I | + .21 | | | | | |
| | | | | | | | |
| Pipeline Commodity Cost | K | + .04 | | | | | |
| | | | | | | | |
| Pipeline In-Kind Fuel Cost * | E61 | + 1.74 % | | | | | |
| | | | | | | | |
| LDC Distribution Cost | M | + .20 | | | | | |
| | | | | | | | |
| Firm Supply Premium | N | + 0.0 | | | | | |

* Summer and winter values are different from the averages show here

The resource planning models require utility gas prices in terms of their fixed and variable components. Variable costs include wellhead prices adjusted for regional differences, pipeline fuel costs, and pipeline commodity charges. These are costs that can be avoided if electricity is not generated. In addition, some portion of the pipeline capacity charge may be avoided through resale in the capacity release market. The share of firm pipeline capacity costs that can be recovered by resale in the capacity release market is a parameter in the model and is currently assumed to equal 10 percent. For example, if it were not possible to recover any pipeline capacity costs then they become fixed costs. The other potentially fixed cost is any premium that must be paid to secure firm gas supply, but this is currently assumed to be zero. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

**Table B1-2: East-Side Cost Components for Calculating Delivered Natural Gas Prices.**

| Cost Component | Components Column | Constant Costs (2000$/MMBtu) | Scenario Variant | | | | |
|---|---|---|---|---|---|---|---|
| | | | L | ML | M | MH | H |
| U.S. Wellhead Price | B | | | | | | |
| Henry Hub Price | C | | | | | | |
| AECO Price | P | | | | | | |
| | | | | | | | |
| Pipeline Capacity Cost | | | | | | | |
| Firm Rolled-In | F | + .29 | | | | | |
| Firm Incremental | H | +.45 in 2007 + growth | -0.1 | 0.1 | 0.3 | 0.5 | 0.7 |
| Released Capacity Cost * | J | + .23 | | | | | |
| | | | | | | | |
| Pipeline Commodity Cost | L | + .01 | | | | | |
| | | | | | | | |
| Pipeline In-Kind Fuel Cost * | F62 | + 2.80 % | | | | | |
| | | | | | | | |
| LDC Distribution Cost | M | + .20 | | | | | |
| | | | | | | | |
| Firm Supply Premium | N | + 0.0 | | | | | |

* Summer and winter values are different from the averages show here

## Oil Model

The oil price forecasting model first estimates the refiner price of distillate and residual oil based on the assumed world price for crude oil. This is done using a very simple model of refinery economics.[14] Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding mark-ups based on the historical difference between calculated refiner wholesale prices and actual retail prices.

The simple model of refiner economics considers the cost of crude oil, the cost of refining crude oil into heavy and light oil products, and the value of those products in the market. It assumes that refiners will decide on their production mix so that their profits will be maximized. That is, the difference between the revenue received from the sale of products and the costs of crude oil and refining it into products will be maximized.

The underlying assumptions are as follows:

Refining costs:

Simple refining
- $2.15 per barrel in 2000$.
- Saudi light yields 47 percent heavy oil.
- 3 percent energy penalty.

Complex refining
- $5.38 per barrel in 2000$.
- yield 100 percent light oil.
- 12 percent energy penalty, about 6-8 percent above simple refining.

Desulpherization
- $3.91 per barrel in 2000$.
- 4 to - 8 percent energy penalty.
- Assumed not to be necessary in NW.

Profit Equations:

Simple refinery

Revenue = .47H + .53L
Cost = C + .03C + 2.15
Profit = (.47H + .53L) - (C + .03C + 2.15)

Where:
.47 is residual oil output share.
.53 is distillate oil output share.
H is residual oil wholesale price.
L is distillate oil wholesale price.
C is cost of crude oil
.03 is the energy penalty for simple refining.

[14] This refinery model evolved from the old Council fuel price forecasting method developed by Energy Analysis and Planning, Inc. That company has evolved into Economic Insight Inc.

2.15 is the refining cost per barrel.

Complex refinery

Revenue $= L$

Cost $= C + .12C + 5.38$

Profit $= L - (C + .12C + 5.38)$

Equilibrium Condition: Profit from heavy products equals profit from light products at the margin.

$$.47H + .53L - C - .03C - 2.15 = L - C - .12C - 5.38$$

Solve for product prices:

$$.47H + .53L - L = .03C - .12C - 5.38 + 2.15$$

$$.47(H - L) = -.09C - 3.23$$

$$(H - L) = -.1915C - 6.8723$$

Using $L = C + .12C + 5.38$ gives

$$H = -.1915C - 6.8723 + C + .12C + 5.38$$

$$H = .9285C - 1.5133$$ (Equation for residual oil price as a function of crude oil price.)

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (2000$) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based mark-ups are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices are then consumption weighted to get an average oil price for the sector. The residential sector does not use residual oil so only a distillate retail price is calculated.

## Coal Model

The coal model is a very simple approach. Average Western mine-mouth coal prices are forecast by applying assumed, scenario-specific, growth rates to a base year level. Regional utility and industry prices, and state-specific utility prices are forecast based on time- invariant differentials from western the mine-mouth prices.

## Model Components  (Tabs in the Excel Workbook)

DOC -- Describes files in the forecast model

NGFC -- Contains historical prices and the forecast range of wellhead gas prices.  Scenarios are to be copied into MAIN for each case. Contains GDP deflators for converting historical to study year dollars.

WOPFC -- Contains historical prices and the forecast range of world oil prices.  Scenarios are to be copied into MAIN for each case.

MAIN -- Contains drivers for forecast model and includes scenario varient values. (Avg. wellhead, world oil, GNP deflators etc. Displays boiler fuel relative gas, oil, coal prices

Basis -- Contains regional basis differential assumptions for each scenario To be copied into MAIN for each scenario.

NG West -- Develops forecasts of natural gas prices at major Western pricing points

Components -- Combines the various components of pipeline and distribution cost, regional wellhead price difference, and other add-ons to the wellhead gas price.  These adders are used in the INDUST and NWUTIL sheets.

RES_COM -- Residential & Commercial gas price model, linked to MAIN wellhead prices by retail price differences.

INDUST -- Industrial gas price model, linked to MAIN wellhead Large interruptible, Avg. transport, through LDC & Mixed

NWUTIL -- PNW Utility gas price model, linked to MAIN wellhead Interruptible and Firm burner-tip

00$ NWUtil -- Shows derivation of West-side and East-side Firm utility gas prices

AURORA -- Develops fixed and variable natural gas prices for AURORA™ Model pricing points in the WECC

GASSUM -- Summary table for gas price forecasts, linked to the individual sector worksheets.

OILMOD -- Estimates retail oil prices for all sectors, linked to MAIN world oil price forecasts.

OilSum -- Summary of retail oil price forecasts for residual and distillate in both midyear 2000 dollars and Jan 2000 dollars.

COALMOD -- Forecasts industrial coal prices based on exogenous growth rate read from MAIN.

Tables -- Develops tables to be included in forecast documents

FUELS -- Puts the fuel price forecasts in the format needed for input to demand forecasting models, converts to 1980 dollars

Export -- File to be exported for demand model inputs.

## APPENDIX B2 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL MARKET PRICES

**Table B2-1 - Medium**
**Regional Electricity Generation Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium Case** | | | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
| 2000 | 3.60 | 3.37 | 5.98 | 6.58 | 3.77 |
| 2001 | 4.03 | 4.14 | 3.59 | 4.15 | 4.59 |
| 2002 | 2.80 | 2.57 | 2.65 | 3.18 | 2.97 |
| 2003 | 4.62 | 4.94 | 4.32 | 4.88 | 5.41 |
| 2004 | 5.45 | 5.12 | 5.21 | 5.85 | 5.66 |
| 2005 | 5.30 | 4.97 | 5.06 | 5.69 | 5.50 |
| 2006 | 5.01 | 4.68 | 4.78 | 5.45 | 5.22 |
| 2007 | 4.74 | 4.40 | 4.50 | 5.17 | 4.99 |
| 2008 | 4.48 | 4.14 | 4.24 | 4.91 | 4.72 |
| 2009 | 4.23 | 3.89 | 4.00 | 4.67 | 4.47 |
| 2010 | 4.00 | 3.66 | 3.77 | 4.43 | 4.23 |
| 2011 | 3.96 | 3.62 | 3.73 | 4.39 | 4.19 |
| 2012 | 3.92 | 3.58 | 3.69 | 4.35 | 4.15 |
| 2013 | 3.88 | 3.54 | 3.65 | 4.32 | 4.11 |
| 2014 | 3.84 | 3.50 | 3.61 | 4.28 | 4.07 |
| 2015 | 3.80 | 3.46 | 3.57 | 4.24 | 4.03 |
| 2016 | 3.82 | 3.48 | 3.59 | 4.26 | 4.05 |
| 2017 | 3.84 | 3.50 | 3.61 | 4.28 | 4.07 |
| 2018 | 3.86 | 3.52 | 3.63 | 4.30 | 4.10 |
| 2019 | 3.88 | 3.54 | 3.65 | 4.33 | 4.12 |
| 2020 | 3.90 | 3.56 | 3.67 | 4.35 | 4.14 |
| 2021 | 3.92 | 3.58 | 3.69 | 4.37 | 4.16 |
| 2022 | 3.94 | 3.60 | 3.71 | 4.39 | 4.18 |
| 2023 | 3.96 | 3.62 | 3.73 | 4.41 | 4.21 |
| 2024 | 3.98 | 3.64 | 3.75 | 4.44 | 4.23 |
| 2025 | 4.00 | 3.66 | 3.77 | 4.46 | 4.25 |

**Table B2-2 - Low**
**Regional Electricity Generation Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Low Case** | | | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
| 2000 | 3.60 | 3.37 | 5.98 | 6.58 | 3.77 |
| 2001 | 4.03 | 4.14 | 3.59 | 4.15 | 4.59 |
| 2002 | 2.80 | 2.57 | 2.65 | 3.18 | 2.97 |
| 2003 | 4.62 | 4.94 | 4.32 | 4.88 | 5.41 |
| 2004 | 4.75 | 4.41 | 4.52 | 5.14 | 4.93 |
| 2005 | 4.50 | 4.16 | 4.27 | 4.88 | 4.67 |
| 2006 | 4.15 | 3.81 | 3.92 | 4.58 | 4.33 |
| 2007 | 3.83 | 3.49 | 3.60 | 4.25 | 4.05 |
| 2008 | 3.53 | 3.19 | 3.30 | 3.95 | 3.74 |
| 2009 | 3.25 | 2.91 | 3.03 | 3.67 | 3.45 |
| 2010 | 3.00 | 2.65 | 2.77 | 3.41 | 3.19 |
| 2011 | 2.95 | 2.60 | 2.72 | 3.36 | 3.13 |
| 2012 | 2.90 | 2.55 | 2.67 | 3.31 | 3.08 |
| 2013 | 2.85 | 2.50 | 2.62 | 3.25 | 3.03 |
| 2014 | 2.80 | 2.45 | 2.57 | 3.20 | 2.98 |
| 2015 | 2.75 | 2.40 | 2.53 | 3.15 | 2.93 |
| 2016 | 2.78 | 2.43 | 2.55 | 3.18 | 2.96 |
| 2017 | 2.81 | 2.46 | 2.58 | 3.21 | 2.99 |
| 2018 | 2.84 | 2.49 | 2.61 | 3.24 | 3.02 |
| 2019 | 2.87 | 2.52 | 2.64 | 3.27 | 3.05 |
| 2020 | 2.90 | 2.55 | 2.67 | 3.30 | 3.08 |
| 2021 | 2.92 | 2.57 | 2.69 | 3.32 | 3.10 |
| 2022 | 2.94 | 2.59 | 2.71 | 3.34 | 3.12 |
| 2023 | 2.96 | 2.61 | 2.73 | 3.36 | 3.14 |
| 2024 | 2.98 | 2.63 | 2.75 | 3.38 | 3.16 |
| 2025 | 3.00 | 2.65 | 2.77 | 3.40 | 3.18 |

**Table B2-3 - Medium-Low**
**Regional Electricity Generation Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium Low Case** | | | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
| 2000 | 3.60 | 3.37 | 5.98 | 6.58 | 3.77 |
| 2001 | 4.03 | 4.14 | 3.59 | 4.15 | 4.59 |
| 2002 | 2.80 | 2.57 | 2.65 | 3.18 | 2.97 |
| 2003 | 4.62 | 4.94 | 4.32 | 4.88 | 5.41 |
| 2004 | 5.20 | 4.87 | 4.96 | 5.59 | 5.40 |
| 2005 | 4.90 | 4.57 | 4.67 | 5.29 | 5.09 |
| 2006 | 4.53 | 4.19 | 4.30 | 4.96 | 4.72 |
| 2007 | 4.18 | 3.84 | 3.95 | 4.61 | 4.42 |
| 2008 | 3.87 | 3.52 | 3.64 | 4.29 | 4.09 |
| 2009 | 3.57 | 3.23 | 3.34 | 3.99 | 3.78 |
| 2010 | 3.30 | 2.96 | 3.07 | 3.72 | 3.50 |
| 2011 | 3.32 | 2.98 | 3.09 | 3.74 | 3.52 |
| 2012 | 3.34 | 3.00 | 3.11 | 3.76 | 3.54 |
| 2013 | 3.36 | 3.02 | 3.13 | 3.78 | 3.57 |
| 2014 | 3.38 | 3.04 | 3.15 | 3.80 | 3.59 |
| 2015 | 3.40 | 3.06 | 3.17 | 3.82 | 3.61 |
| 2016 | 3.42 | 3.08 | 3.19 | 3.84 | 3.63 |
| 2017 | 3.44 | 3.10 | 3.21 | 3.86 | 3.65 |
| 2018 | 3.46 | 3.12 | 3.23 | 3.89 | 3.67 |
| 2019 | 3.48 | 3.14 | 3.25 | 3.91 | 3.69 |
| 2020 | 3.50 | 3.16 | 3.27 | 3.93 | 3.71 |
| 2021 | 3.50 | 3.16 | 3.27 | 3.93 | 3.71 |
| 2022 | 3.50 | 3.16 | 3.27 | 3.93 | 3.71 |
| 2023 | 3.50 | 3.16 | 3.27 | 3.93 | 3.72 |
| 2024 | 3.50 | 3.16 | 3.27 | 3.93 | 3.72 |
| 2025 | 3.50 | 3.16 | 3.27 | 3.93 | 3.72 |

**Table B2-4 - Medium-High**
**Regional Electricity Generation Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium High Case** | | | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
| 2000 | 3.60 | 3.37 | 5.98 | 6.58 | 3.77 |
| 2001 | 4.03 | 4.14 | 3.59 | 4.15 | 4.59 |
| 2002 | 2.80 | 2.57 | 2.65 | 3.18 | 2.97 |
| 2003 | 4.62 | 4.94 | 4.32 | 4.88 | 5.41 |
| 2004 | 5.60 | 5.27 | 5.36 | 6.00 | 5.81 |
| 2005 | 6.00 | 5.67 | 5.76 | 6.40 | 6.23 |
| 2006 | 5.66 | 5.34 | 5.43 | 6.11 | 5.90 |
| 2007 | 5.35 | 5.02 | 5.11 | 5.80 | 5.62 |
| 2008 | 5.05 | 4.72 | 4.81 | 5.49 | 5.31 |
| 2009 | 4.77 | 4.43 | 4.53 | 5.21 | 5.02 |
| 2010 | 4.50 | 4.16 | 4.27 | 4.94 | 4.75 |
| 2011 | 4.46 | 4.12 | 4.23 | 4.91 | 4.71 |
| 2012 | 4.42 | 4.08 | 4.19 | 4.87 | 4.67 |
| 2013 | 4.38 | 4.04 | 4.15 | 4.83 | 4.63 |
| 2014 | 4.34 | 4.00 | 4.11 | 4.79 | 4.59 |
| 2015 | 4.30 | 3.96 | 4.07 | 4.76 | 4.55 |
| 2016 | 4.31 | 3.97 | 4.08 | 4.77 | 4.57 |
| 2017 | 4.32 | 3.98 | 4.09 | 4.78 | 4.58 |
| 2018 | 4.33 | 3.99 | 4.10 | 4.79 | 4.59 |
| 2019 | 4.34 | 4.00 | 4.11 | 4.81 | 4.61 |
| 2020 | 4.35 | 4.01 | 4.12 | 4.82 | 4.62 |
| 2021 | 4.38 | 4.04 | 4.15 | 4.85 | 4.65 |
| 2022 | 4.41 | 4.07 | 4.18 | 4.89 | 4.68 |
| 2023 | 4.44 | 4.10 | 4.21 | 4.92 | 4.72 |
| 2024 | 4.47 | 4.13 | 4.24 | 4.95 | 4.75 |
| 2025 | 4.50 | 4.16 | 4.27 | 4.99 | 4.79 |

**Table B2-5 - High**
**Regional Electricity Generation Natural Gas Prices**
**(2000$ Per MMBtu)**

| High Case | | | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
| 2000 | 3.60 | 3.37 | 5.98 | 6.58 | 3.77 |
| 2001 | 4.03 | 4.14 | 3.59 | 4.15 | 4.59 |
| 2002 | 2.80 | 2.57 | 2.65 | 3.18 | 2.97 |
| 2003 | 4.62 | 4.94 | 4.32 | 4.88 | 5.41 |
| 2004 | 5.80 | 5.47 | 5.56 | 6.20 | 6.02 |
| 2005 | 6.75 | 6.43 | 6.51 | 7.16 | 7.00 |
| 2006 | 6.36 | 6.03 | 6.12 | 6.81 | 6.62 |
| 2007 | 5.99 | 5.66 | 5.75 | 6.44 | 6.28 |
| 2008 | 5.64 | 5.31 | 5.40 | 6.09 | 5.92 |
| 2009 | 5.31 | 4.98 | 5.07 | 5.77 | 5.59 |
| 2010 | 5.00 | 4.67 | 4.77 | 5.46 | 5.27 |
| 2011 | 4.98 | 4.65 | 4.75 | 5.44 | 5.25 |
| 2012 | 4.96 | 4.63 | 4.73 | 5.42 | 5.24 |
| 2013 | 4.94 | 4.61 | 4.71 | 5.41 | 5.22 |
| 2014 | 4.92 | 4.59 | 4.69 | 5.39 | 5.20 |
| 2015 | 4.90 | 4.57 | 4.67 | 5.37 | 5.18 |
| 2016 | 4.92 | 4.59 | 4.69 | 5.40 | 5.21 |
| 2017 | 4.94 | 4.61 | 4.71 | 5.42 | 5.23 |
| 2018 | 4.96 | 4.63 | 4.73 | 5.45 | 5.26 |
| 2019 | 4.98 | 4.65 | 4.75 | 5.47 | 5.28 |
| 2020 | 5.00 | 4.67 | 4.77 | 5.50 | 5.30 |
| 2021 | 5.02 | 4.69 | 4.79 | 5.52 | 5.33 |
| 2022 | 5.04 | 4.71 | 4.81 | 5.55 | 5.35 |
| 2023 | 5.06 | 4.73 | 4.83 | 5.57 | 5.38 |
| 2024 | 5.08 | 4.75 | 4.85 | 5.59 | 5.40 |
| 2025 | 5.10 | 4.77 | 4.87 | 5.62 | 5.42 |

## APPENDIX B3 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL RETAIL NATURAL GAS PRICES

**Table B3-1 - Medium**
**Pacific Northwest Retail Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium Case** | | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | Residential | Commercial | Industrial Average | Utility Average |
| 2000 | 3.60 | 7.09 | 5.95 | 5.91 | 5.13 |
| 2001 | 4.03 | 8.38 | 6.68 | 4.49 | 4.32 |
| 2002 | 2.80 | 7.05 | 6.05 | 3.55 | 3.03 |
| 2003 | 4.62 | 8.87 | 7.87 | 5.29 | 5.10 |
| 2004 | 5.45 | 9.70 | 8.70 | 6.18 | 5.67 |
| 2005 | 5.30 | 9.55 | 8.55 | 6.02 | 5.52 |
| 2006 | 5.01 | 9.26 | 8.26 | 5.73 | 5.24 |
| 2007 | 4.74 | 8.99 | 7.99 | 5.45 | 4.97 |
| 2008 | 4.48 | 8.73 | 7.73 | 5.19 | 4.71 |
| 2009 | 4.23 | 8.48 | 7.48 | 4.94 | 4.46 |
| 2010 | 4.00 | 8.25 | 7.25 | 4.70 | 4.22 |
| 2011 | 3.96 | 8.21 | 7.21 | 4.66 | 4.18 |
| 2012 | 3.92 | 8.17 | 7.17 | 4.62 | 4.14 |
| 2013 | 3.88 | 8.13 | 7.13 | 4.58 | 4.10 |
| 2014 | 3.84 | 8.09 | 7.09 | 4.54 | 4.06 |
| 2015 | 3.80 | 8.05 | 7.05 | 4.50 | 4.02 |
| 2016 | 3.82 | 8.07 | 7.07 | 4.51 | 4.04 |
| 2017 | 3.84 | 8.09 | 7.09 | 4.53 | 4.06 |
| 2018 | 3.86 | 8.11 | 7.11 | 4.55 | 4.08 |
| 2019 | 3.88 | 8.13 | 7.13 | 4.57 | 4.10 |
| 2020 | 3.90 | 8.15 | 7.15 | 4.59 | 4.13 |
| 2021 | 3.92 | 8.17 | 7.17 | 4.61 | 4.15 |
| 2022 | 3.94 | 8.19 | 7.19 | 4.63 | 4.17 |
| 2023 | 3.96 | 8.21 | 7.21 | 4.65 | 4.19 |
| 2024 | 3.98 | 8.23 | 7.23 | 4.67 | 4.21 |
| 2025 | 4.00 | 8.25 | 7.25 | 4.68 | 4.23 |

**Table B3-2 - Low**
**Pacific Northwest Retail Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Low Case** | | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | Residential | Commercial | Industrial Average | Utility Average |
| 2000 | 3.60 | 7.09 | 5.95 | 5.91 | 5.13 |
| 2001 | 4.03 | 8.38 | 6.68 | 4.49 | 4.32 |
| 2002 | 2.80 | 7.05 | 6.05 | 3.55 | 3.03 |
| 2003 | 4.62 | 8.87 | 7.87 | 5.29 | 5.10 |
| 2004 | 4.75 | 9.00 | 8.00 | 5.47 | 4.96 |
| 2005 | 4.50 | 8.75 | 7.75 | 5.22 | 4.70 |
| 2006 | 4.15 | 8.40 | 7.40 | 4.86 | 4.36 |
| 2007 | 3.83 | 8.08 | 7.08 | 4.53 | 4.04 |
| 2008 | 3.53 | 7.78 | 6.78 | 4.23 | 3.73 |
| 2009 | 3.25 | 7.50 | 6.50 | 3.95 | 3.45 |
| 2010 | 3.00 | 7.25 | 6.25 | 3.69 | 3.19 |
| 2011 | 2.95 | 7.20 | 6.20 | 3.64 | 3.14 |
| 2012 | 2.90 | 7.15 | 6.15 | 3.59 | 3.09 |
| 2013 | 2.85 | 7.10 | 6.10 | 3.54 | 3.04 |
| 2014 | 2.80 | 7.05 | 6.05 | 3.49 | 2.99 |
| 2015 | 2.75 | 7.00 | 6.00 | 3.44 | 2.94 |
| 2016 | 2.78 | 7.03 | 6.03 | 3.46 | 2.97 |
| 2017 | 2.81 | 7.06 | 6.06 | 3.49 | 3.00 |
| 2018 | 2.84 | 7.09 | 6.09 | 3.52 | 3.03 |
| 2019 | 2.87 | 7.12 | 6.12 | 3.55 | 3.06 |
| 2020 | 2.90 | 7.15 | 6.15 | 3.58 | 3.09 |
| 2021 | 2.92 | 7.17 | 6.17 | 3.60 | 3.11 |
| 2022 | 2.94 | 7.19 | 6.19 | 3.62 | 3.13 |
| 2023 | 2.96 | 7.21 | 6.21 | 3.64 | 3.15 |
| 2024 | 2.98 | 7.23 | 6.23 | 3.66 | 3.17 |
| 2025 | 3.00 | 7.25 | 6.25 | 3.68 | 3.19 |

**Table B3-3 - Medium-Low**
**Pacific Northwest Retail Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium Low Case** | | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | Residential | Commercial | Industrial Average | Utility Average |
| 2000 | 3.60 | 7.09 | 5.95 | 5.91 | 5.13 |
| 2001 | 4.03 | 8.38 | 6.68 | 4.49 | 4.32 |
| 2002 | 2.80 | 7.05 | 6.05 | 3.55 | 3.03 |
| 2003 | 4.62 | 8.87 | 7.87 | 5.29 | 5.10 |
| 2004 | 5.20 | 9.45 | 8.45 | 5.92 | 5.42 |
| 2005 | 4.90 | 9.15 | 8.15 | 5.62 | 5.11 |
| 2006 | 4.53 | 8.78 | 7.78 | 5.24 | 4.75 |
| 2007 | 4.18 | 8.43 | 7.43 | 4.89 | 4.41 |
| 2008 | 3.87 | 8.12 | 7.12 | 4.57 | 4.08 |
| 2009 | 3.57 | 7.82 | 6.82 | 4.27 | 3.78 |
| 2010 | 3.30 | 7.55 | 6.55 | 4.00 | 3.50 |
| 2011 | 3.32 | 7.57 | 6.57 | 4.02 | 3.52 |
| 2012 | 3.34 | 7.59 | 6.59 | 4.03 | 3.54 |
| 2013 | 3.36 | 7.61 | 6.61 | 4.05 | 3.56 |
| 2014 | 3.38 | 7.63 | 6.63 | 4.07 | 3.58 |
| 2015 | 3.40 | 7.65 | 6.65 | 4.09 | 3.61 |
| 2016 | 3.42 | 7.67 | 6.67 | 4.11 | 3.63 |
| 2017 | 3.44 | 7.69 | 6.69 | 4.13 | 3.65 |
| 2018 | 3.46 | 7.71 | 6.71 | 4.15 | 3.67 |
| 2019 | 3.48 | 7.73 | 6.73 | 4.17 | 3.69 |
| 2020 | 3.50 | 7.75 | 6.75 | 4.19 | 3.71 |
| 2021 | 3.50 | 7.75 | 6.75 | 4.19 | 3.71 |
| 2022 | 3.50 | 7.75 | 6.75 | 4.18 | 3.71 |
| 2023 | 3.50 | 7.75 | 6.75 | 4.18 | 3.71 |
| 2024 | 3.50 | 7.75 | 6.75 | 4.18 | 3.71 |
| 2025 | 3.50 | 7.75 | 6.75 | 4.18 | 3.71 |

**Table B3-4 - Medium-High**
**Pacific Northwest Retail Natural Gas Prices**
**(2000$ Per MMBtu)**

| **Medium High Case** | | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | Residential | Commercial | Industrial Average | Utility Average |
| 2000 | 3.60 | 7.09 | 5.95 | 5.91 | 5.13 |
| 2001 | 4.03 | 8.38 | 6.68 | 4.49 | 4.32 |
| 2002 | 2.80 | 7.05 | 6.05 | 3.55 | 3.03 |
| 2003 | 4.62 | 8.87 | 7.87 | 5.29 | 5.10 |
| 2004 | 5.60 | 9.85 | 8.85 | 6.33 | 5.83 |
| 2005 | 6.00 | 10.25 | 9.25 | 6.73 | 6.24 |
| 2006 | 5.66 | 9.91 | 8.91 | 6.39 | 5.91 |
| 2007 | 5.35 | 9.60 | 8.60 | 6.07 | 5.60 |
| 2008 | 5.05 | 9.30 | 8.30 | 5.77 | 5.29 |
| 2009 | 4.77 | 9.02 | 8.02 | 5.48 | 5.01 |
| 2010 | 4.50 | 8.75 | 7.75 | 5.21 | 4.73 |
| 2011 | 4.46 | 8.71 | 7.71 | 5.17 | 4.69 |
| 2012 | 4.42 | 8.67 | 7.67 | 5.12 | 4.65 |
| 2013 | 4.38 | 8.63 | 7.63 | 5.08 | 4.61 |
| 2014 | 4.34 | 8.59 | 7.59 | 5.04 | 4.58 |
| 2015 | 4.30 | 8.55 | 7.55 | 5.00 | 4.54 |
| 2016 | 4.31 | 8.56 | 7.56 | 5.01 | 4.55 |
| 2017 | 4.32 | 8.57 | 7.57 | 5.02 | 4.56 |
| 2018 | 4.33 | 8.58 | 7.58 | 5.03 | 4.57 |
| 2019 | 4.34 | 8.59 | 7.59 | 5.04 | 4.58 |
| 2020 | 4.35 | 8.60 | 7.60 | 5.04 | 4.59 |
| 2021 | 4.38 | 8.63 | 7.63 | 5.07 | 4.63 |
| 2022 | 4.41 | 8.66 | 7.66 | 5.10 | 4.66 |
| 2023 | 4.44 | 8.69 | 7.69 | 5.13 | 4.69 |
| 2024 | 4.47 | 8.72 | 7.72 | 5.16 | 4.72 |
| 2025 | 4.50 | 8.75 | 7.75 | 5.19 | 4.75 |

**Table B3-5 - High**
**Pacific Northwest Retail Natural Gas Prices**
**(2000$ Per MMBtu)**

| **High Case** | | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| Year | U.S. Wellhead Price | Residential | Commercial | Industrial Average | Utility Average |
| 2000 | 3.60 | 7.09 | 5.95 | 5.91 | 5.13 |
| 2001 | 4.03 | 8.38 | 6.68 | 4.49 | 4.32 |
| 2002 | 2.80 | 7.05 | 6.05 | 3.55 | 3.03 |
| 2003 | 4.62 | 8.87 | 7.87 | 5.29 | 5.10 |
| 2004 | 5.80 | 10.05 | 9.05 | 6.53 | 6.03 |
| 2005 | 6.75 | 11.00 | 10.00 | 7.49 | 7.01 |
| 2006 | 6.36 | 10.61 | 9.61 | 7.09 | 6.62 |
| 2007 | 5.99 | 10.24 | 9.24 | 6.71 | 6.25 |
| 2008 | 5.64 | 9.89 | 8.89 | 6.36 | 5.90 |
| 2009 | 5.31 | 9.56 | 8.56 | 6.03 | 5.56 |
| 2010 | 5.00 | 9.25 | 8.25 | 5.71 | 5.25 |
| 2011 | 4.98 | 9.23 | 8.23 | 5.69 | 5.23 |
| 2012 | 4.96 | 9.21 | 8.21 | 5.67 | 5.21 |
| 2013 | 4.94 | 9.19 | 8.19 | 5.65 | 5.19 |
| 2014 | 4.92 | 9.17 | 8.17 | 5.63 | 5.17 |
| 2015 | 4.90 | 9.15 | 8.15 | 5.61 | 5.16 |
| 2016 | 4.92 | 9.17 | 8.17 | 5.62 | 5.18 |
| 2017 | 4.94 | 9.19 | 8.19 | 5.64 | 5.20 |
| 2018 | 4.96 | 9.21 | 8.21 | 5.66 | 5.22 |
| 2019 | 4.98 | 9.23 | 8.23 | 5.68 | 5.24 |
| 2020 | 5.00 | 9.25 | 8.25 | 5.70 | 5.27 |
| 2021 | 5.02 | 9.27 | 8.27 | 5.72 | 5.29 |
| 2022 | 5.04 | 9.29 | 8.29 | 5.74 | 5.31 |
| 2023 | 5.06 | 9.31 | 8.31 | 5.76 | 5.33 |
| 2024 | 5.08 | 9.33 | 8.33 | 5.78 | 5.36 |
| 2025 | 5.10 | 9.35 | 8.35 | 5.80 | 5.38 |

## APPENDIX B4 - FORECAST TABLES FOR WORLD OIL AND REGIONAL RETAIL OIL PRICES

**Table B4-1 - Medium**
**Retail Oil Price Forecast**

| Medium Case | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | World Oil Price (00$/Bbl.) | Industrial Residual Oil Price | Industrial Distillate Oil Price (00$/MMBtu) | Average Industrial Oil Price | Commercial Residual Oil Price | Commercial Distillate Oil Price (00$/MMBtu) | Average Commercial Oil Price | Average Residential Oil Price (00$/MMBtu) | Utility Residual Oil Price (00$/MMBtu) | Utility Distillate Oil Price |
| 2000 | 27.70 | 4.09 | 7.25 | 7.06 | 4.14 | 6.83 | 6.70 | 9.23 | 4.09 | 6.71 |
| 2001 | 21.49 | 3.17 | 6.06 | 5.89 | 3.22 | 5.64 | 5.52 | 8.04 | 3.17 | 5.52 |
| 2002 | 22.81 | 3.37 | 6.31 | 6.14 | 3.42 | 5.89 | 5.77 | 8.29 | 3.37 | 5.77 |
| 2003 | 26.23 | 3.87 | 6.97 | 6.78 | 3.92 | 6.55 | 6.42 | 8.95 | 3.87 | 6.43 |
| 2004 | 34.00 | 5.02 | 8.46 | 8.26 | 5.07 | 8.04 | 7.90 | 10.44 | 5.02 | 7.92 |
| 2005 | 30.00 | 4.43 | 7.69 | 7.50 | 4.48 | 7.27 | 7.14 | 9.67 | 4.43 | 7.15 |
| 2006 | 29.37 | 4.34 | 7.57 | 7.38 | 4.39 | 7.15 | 7.02 | 9.55 | 4.34 | 7.03 |
| 2007 | 28.76 | 4.25 | 7.45 | 7.27 | 4.30 | 7.03 | 6.90 | 9.43 | 4.25 | 6.91 |
| 2008 | 28.16 | 4.16 | 7.34 | 7.15 | 4.21 | 6.92 | 6.79 | 9.32 | 4.16 | 6.80 |
| 2009 | 27.57 | 4.07 | 7.23 | 7.04 | 4.12 | 6.81 | 6.68 | 9.21 | 4.07 | 6.69 |
| 2010 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2011 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2012 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2013 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2014 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2015 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2016 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2017 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2018 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2019 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2020 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2021 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2022 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2023 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2024 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2025 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |

## Table B4-2 - Low
## Retail Oil Price Forecast

| Low Case | | Industrial Residual Oil Price | Industrial Distillate Oil Price | Average Industrial Oil Price | Commercial Residual Oil Price | Commercial Distillate Oil Price | Average Commercial Oil Price | Average Residential Oil Price | Utility Residual Oil Price | Utility Distillate Oil Price |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | World Oil Price (00$/Bbl.) | | (00$/MMBtu) | | | (00$/MMBtu) | | (00$/MMBtu) | (00$/MMBtu) | |
| 2000 | 27.70 | 4.09 | 7.25 | 7.06 | 4.14 | 6.83 | 6.70 | 9.23 | 4.09 | 6.71 |
| 2001 | 21.49 | 3.17 | 6.06 | 5.89 | 3.22 | 5.64 | 5.52 | 8.04 | 3.17 | 5.52 |
| 2002 | 22.81 | 3.37 | 6.31 | 6.14 | 3.42 | 5.89 | 5.77 | 8.29 | 3.37 | 5.77 |
| 2003 | 26.23 | 3.87 | 6.97 | 6.78 | 3.92 | 6.55 | 6.42 | 8.95 | 3.87 | 6.43 |
| 2004 | 30.00 | 4.43 | 7.69 | 7.50 | 4.48 | 7.27 | 7.14 | 9.67 | 4.43 | 7.15 |
| 2005 | 25.00 | 3.69 | 6.73 | 6.55 | 3.74 | 6.31 | 6.19 | 8.71 | 3.69 | 6.19 |
| 2006 | 23.91 | 3.53 | 6.52 | 6.34 | 3.58 | 6.10 | 5.98 | 8.50 | 3.53 | 5.98 |
| 2007 | 22.87 | 3.38 | 6.32 | 6.15 | 3.43 | 5.90 | 5.78 | 8.30 | 3.38 | 5.78 |
| 2008 | 21.87 | 3.23 | 6.13 | 5.96 | 3.28 | 5.71 | 5.59 | 8.11 | 3.23 | 5.59 |
| 2009 | 20.91 | 3.09 | 5.94 | 5.78 | 3.14 | 5.52 | 5.41 | 7.92 | 3.09 | 5.40 |
| 2010 | 20.00 | 2.95 | 5.77 | 5.60 | 3.00 | 5.35 | 5.24 | 7.75 | 2.95 | 5.23 |
| 2011 | 19.58 | 2.89 | 5.69 | 5.52 | 2.94 | 5.27 | 5.16 | 7.67 | 2.89 | 5.15 |
| 2012 | 19.17 | 2.83 | 5.61 | 5.45 | 2.88 | 5.19 | 5.08 | 7.59 | 2.83 | 5.07 |
| 2013 | 18.77 | 2.77 | 5.53 | 5.37 | 2.82 | 5.11 | 5.00 | 7.51 | 2.77 | 4.99 |
| 2014 | 18.38 | 2.71 | 5.46 | 5.30 | 2.76 | 5.04 | 4.93 | 7.44 | 2.71 | 4.92 |
| 2015 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2016 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2017 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2018 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2019 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2020 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2021 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2022 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2023 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2024 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |
| 2025 | 18.00 | 2.66 | 5.38 | 5.22 | 2.71 | 4.96 | 4.86 | 7.36 | 2.66 | 4.84 |

**Table B4-3 - Medium-Low**
**Retail Oil Price Forecast**

| **Medium Low Case** | | Industrial | Industrial | Average | Commercial | Commercial | Average | Average | Utility | Utility |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | World Oil Price (00$/Bbl.) | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Industrial Oil Price | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Commercial Oil Price | Residential Oil Price (00$/MMBtu) | Residual Oil Price (00$/MMBtu) | Distillate Oil Price |
| 2000 | 27.70 | 4.09 | 7.25 | 7.06 | 4.14 | 6.83 | 6.70 | 9.23 | 4.09 | 6.71 |
| 2001 | 21.49 | 3.17 | 6.06 | 5.89 | 3.22 | 5.64 | 5.52 | 8.04 | 3.17 | 5.52 |
| 2002 | 22.81 | 3.37 | 6.31 | 6.14 | 3.42 | 5.89 | 5.77 | 8.29 | 3.37 | 5.77 |
| 2003 | 26.23 | 3.87 | 6.97 | 6.78 | 3.92 | 6.55 | 6.42 | 8.95 | 3.87 | 6.43 |
| 2004 | 32.00 | 4.73 | 8.08 | 7.88 | 4.78 | 7.66 | 7.52 | 10.06 | 4.73 | 7.54 |
| 2005 | 27.00 | 3.99 | 7.12 | 6.93 | 4.04 | 6.70 | 6.57 | 9.10 | 3.99 | 6.58 |
| 2006 | 26.15 | 3.86 | 6.95 | 6.77 | 3.91 | 6.53 | 6.41 | 8.93 | 3.86 | 6.41 |
| 2007 | 25.32 | 3.74 | 6.79 | 6.61 | 3.79 | 6.37 | 6.25 | 8.77 | 3.74 | 6.25 |
| 2008 | 24.52 | 3.62 | 6.64 | 6.46 | 3.67 | 6.22 | 6.10 | 8.62 | 3.62 | 6.10 |
| 2009 | 23.75 | 3.51 | 6.49 | 6.31 | 3.56 | 6.07 | 5.95 | 8.47 | 3.51 | 5.95 |
| 2010 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2011 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2012 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2013 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2014 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2015 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2016 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2017 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2018 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2019 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2020 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2021 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2022 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2023 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2024 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |
| 2025 | 23.00 | 3.40 | 6.35 | 6.17 | 3.45 | 5.93 | 5.81 | 8.33 | 3.40 | 5.81 |

**Table B4-4 - Medium-High**
**Retail Oil Price Forecast**

| **Medium High Case** | | Industrial | Industrial | Average | Commercial | Commercial | Average | Average | Utility | Utility |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | World Oil Price (00$/Bbl.) | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Industrial Oil Price | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Commercial Oil Price | Residential Oil Price (00$/MMBtu) | Residual Oil Price | Distillate Oil Price (00$/MMBtu) |
| 2000 | 27.70 | 4.09 | 7.25 | 7.06 | 4.14 | 6.83 | 6.70 | 9.23 | 4.09 | 6.71 |
| 2001 | 21.49 | 3.17 | 6.06 | 5.89 | 3.22 | 5.64 | 5.52 | 8.04 | 3.17 | 5.52 |
| 2002 | 22.81 | 3.37 | 6.31 | 6.14 | 3.42 | 5.89 | 5.77 | 8.29 | 3.37 | 5.77 |
| 2003 | 26.23 | 3.87 | 6.97 | 6.78 | 3.92 | 6.55 | 6.42 | 8.95 | 3.87 | 6.43 |
| 2004 | 35.50 | 5.24 | 8.75 | 8.54 | 5.29 | 8.33 | 8.18 | 10.73 | 5.24 | 8.21 |
| 2005 | 36.00 | 5.32 | 8.85 | 8.64 | 5.37 | 8.43 | 8.28 | 10.83 | 5.32 | 8.31 |
| 2006 | 34.71 | 5.13 | 8.60 | 8.39 | 5.18 | 8.18 | 8.03 | 10.58 | 5.13 | 8.06 |
| 2007 | 33.47 | 4.94 | 8.36 | 8.16 | 4.99 | 7.94 | 7.80 | 10.34 | 4.94 | 7.82 |
| 2008 | 32.27 | 4.77 | 8.13 | 7.93 | 4.82 | 7.71 | 7.57 | 10.11 | 4.77 | 7.59 |
| 2009 | 31.11 | 4.59 | 7.91 | 7.71 | 4.64 | 7.49 | 7.35 | 9.89 | 4.59 | 7.37 |
| 2010 | 30.00 | 4.43 | 7.69 | 7.50 | 4.48 | 7.27 | 7.14 | 9.67 | 4.43 | 7.15 |
| 2011 | 29.59 | 4.37 | 7.61 | 7.42 | 4.42 | 7.19 | 7.06 | 9.59 | 4.37 | 7.07 |
| 2012 | 29.18 | 4.31 | 7.53 | 7.35 | 4.36 | 7.11 | 6.98 | 9.51 | 4.31 | 6.99 |
| 2013 | 28.78 | 4.25 | 7.46 | 7.27 | 4.30 | 7.04 | 6.91 | 9.44 | 4.25 | 6.92 |
| 2014 | 28.39 | 4.19 | 7.38 | 7.19 | 4.24 | 6.96 | 6.83 | 9.36 | 4.19 | 6.84 |
| 2015 | 28.00 | 4.13 | 7.31 | 7.12 | 4.18 | 6.89 | 6.76 | 9.29 | 4.13 | 6.77 |
| 2016 | 28.10 | 4.15 | 7.33 | 7.14 | 4.20 | 6.91 | 6.78 | 9.31 | 4.15 | 6.79 |
| 2017 | 28.20 | 4.16 | 7.35 | 7.16 | 4.21 | 6.93 | 6.80 | 9.33 | 4.16 | 6.81 |
| 2018 | 28.30 | 4.18 | 7.36 | 7.18 | 4.23 | 6.94 | 6.81 | 9.34 | 4.18 | 6.82 |
| 2019 | 28.40 | 4.19 | 7.38 | 7.20 | 4.24 | 6.96 | 6.83 | 9.36 | 4.19 | 6.84 |
| 2020 | 28.50 | 4.21 | 7.40 | 7.22 | 4.26 | 6.98 | 6.85 | 9.38 | 4.21 | 6.86 |
| 2021 | 28.60 | 4.22 | 7.42 | 7.23 | 4.27 | 7.00 | 6.87 | 9.40 | 4.22 | 6.88 |
| 2022 | 28.70 | 4.24 | 7.44 | 7.25 | 4.29 | 7.02 | 6.89 | 9.42 | 4.24 | 6.90 |
| 2023 | 28.80 | 4.25 | 7.46 | 7.27 | 4.30 | 7.04 | 6.91 | 9.44 | 4.25 | 6.92 |
| 2024 | 28.90 | 4.27 | 7.48 | 7.29 | 4.32 | 7.06 | 6.93 | 9.46 | 4.27 | 6.94 |
| 2025 | 29.00 | 4.28 | 7.50 | 7.31 | 4.33 | 7.08 | 6.95 | 9.48 | 4.28 | 6.96 |

**Table B4-5 - High**
**Retail Oil Price Forecast**

| **High Case** | | Industrial | Industrial | Average | Commercial | Commercial | Average | Average | Utility | Utility |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | World Oil Price (00$/Bbl.) | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Industrial Oil Price | Residual Oil Price | Distillate Oil Price (00$/MMBtu) | Commercial Oil Price | Residential Oil Price (00$/MMBtu) | Residual Oil Price (00$/MMBtu) | Distillate Oil Price |
| 2000 | 27.70 | 4.09 | 7.25 | 7.06 | 4.14 | 6.83 | 6.70 | 9.23 | 4.09 | 6.71 |
| 2001 | 21.49 | 3.17 | 6.06 | 5.89 | 3.22 | 5.64 | 5.52 | 8.04 | 3.17 | 5.52 |
| 2002 | 22.81 | 3.37 | 6.31 | 6.14 | 3.42 | 5.89 | 5.77 | 8.29 | 3.37 | 5.77 |
| 2003 | 26.23 | 3.87 | 6.97 | 6.78 | 3.92 | 6.55 | 6.42 | 8.95 | 3.87 | 6.43 |
| 2004 | 37.00 | 5.46 | 9.04 | 8.83 | 5.51 | 8.62 | 8.47 | 11.02 | 5.46 | 8.50 |
| 2005 | 38.00 | 5.61 | 9.23 | 9.02 | 5.66 | 8.81 | 8.66 | 11.21 | 5.61 | 8.69 |
| 2006 | 37.38 | 5.52 | 9.11 | 8.90 | 5.57 | 8.69 | 8.54 | 11.09 | 5.52 | 8.57 |
| 2007 | 36.77 | 5.43 | 8.99 | 8.78 | 5.48 | 8.57 | 8.43 | 10.97 | 5.43 | 8.45 |
| 2008 | 36.17 | 5.34 | 8.88 | 8.67 | 5.39 | 8.46 | 8.31 | 10.86 | 5.34 | 8.34 |
| 2009 | 35.58 | 5.25 | 8.76 | 8.56 | 5.30 | 8.34 | 8.20 | 10.74 | 5.25 | 8.22 |
| 2010 | 35.00 | 5.17 | 8.65 | 8.45 | 5.22 | 8.23 | 8.09 | 10.63 | 5.17 | 8.11 |
| 2011 | 34.59 | 5.11 | 8.57 | 8.37 | 5.16 | 8.15 | 8.01 | 10.55 | 5.11 | 8.03 |
| 2012 | 34.19 | 5.05 | 8.50 | 8.29 | 5.10 | 8.08 | 7.93 | 10.48 | 5.05 | 7.96 |
| 2013 | 33.79 | 4.99 | 8.42 | 8.22 | 5.04 | 8.00 | 7.86 | 10.40 | 4.99 | 7.88 |
| 2014 | 33.39 | 4.93 | 8.34 | 8.14 | 4.98 | 7.92 | 7.78 | 10.32 | 4.93 | 7.80 |
| 2015 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2016 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2017 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2018 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2019 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2020 | 33.00 | 4.87 | 8.27 | 8.07 | 4.92 | 7.85 | 7.71 | 10.25 | 4.87 | 7.73 |
| 2021 | 33.20 | 4.90 | 8.31 | 8.11 | 4.95 | 7.89 | 7.75 | 10.29 | 4.90 | 7.77 |
| 2022 | 33.40 | 4.93 | 8.34 | 8.14 | 4.98 | 7.92 | 7.78 | 10.32 | 4.93 | 7.80 |
| 2023 | 33.60 | 4.96 | 8.38 | 8.18 | 5.01 | 7.96 | 7.82 | 10.36 | 4.96 | 7.84 |
| 2024 | 33.80 | 4.99 | 8.42 | 8.22 | 5.04 | 8.00 | 7.86 | 10.40 | 4.99 | 7.88 |
| 2025 | 34.00 | 5.02 | 8.46 | 8.26 | 5.07 | 8.04 | 7.90 | 10.44 | 5.02 | 7.92 |

## APPENDIX B5 - FORECAST TABLES FOR WESTERN MINE-MOUTH AND REGIONAL DELIVERED COAL PRICES

**Table B5-1 - Medium Coal Price Forecasts (2000$ Per MMBtu)**

| Medium Case | | | Selected State Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | Washington | Oregon | Montana | Idaho | Utah | Wyoming |
| 2000 | 0.51 | 2.11 | 1.65 | 1.09 | 0.71 | 0.00 | 1.39 | 0.81 |
| 2001 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2002 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2003 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2004 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2005 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2006 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2007 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2008 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2009 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2010 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2011 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2012 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2013 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2014 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2015 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2016 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2017 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2018 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2019 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2020 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2021 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2022 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2023 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2024 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2025 | 0.51 | 2.11 | 1.50 | 1.05 | 0.52 | 0.96 | 1.13 | 0.70 |

**Table B5-2 - Low**
**Coal Price Forecasts**
**(2000$ Per MMBtu)**

| **Low Case** | | | Selected State Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | Washington | Oregon | Montana | Idaho | Utah | Wyoming |
| 2000 | 0.51 | 2.11 | 1.65 | 1.09 | 0.71 | 0.00 | 1.39 | 0.81 |
| 2001 | 0.51 | 2.11 | 1.50 | 1.04 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2002 | 0.51 | 2.11 | 1.50 | 1.04 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2003 | 0.50 | 2.10 | 1.49 | 1.03 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2004 | 0.50 | 2.10 | 1.49 | 1.03 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2005 | 0.49 | 2.09 | 1.48 | 1.03 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2006 | 0.49 | 2.09 | 1.48 | 1.02 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2007 | 0.49 | 2.09 | 1.48 | 1.02 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2008 | 0.48 | 2.08 | 1.47 | 1.01 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2009 | 0.48 | 2.08 | 1.47 | 1.01 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2010 | 0.47 | 2.07 | 1.46 | 1.01 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2011 | 0.47 | 2.07 | 1.46 | 1.00 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2012 | 0.47 | 2.07 | 1.46 | 1.00 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2013 | 0.46 | 2.06 | 1.45 | 1.00 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2014 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2015 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2016 | 0.45 | 2.05 | 1.44 | 0.98 | 0.46 | 0.90 | 1.07 | 0.64 |
| 2017 | 0.45 | 2.05 | 1.44 | 0.98 | 0.46 | 0.90 | 1.07 | 0.64 |
| 2018 | 0.44 | 2.04 | 1.43 | 0.98 | 0.45 | 0.89 | 1.06 | 0.63 |
| 2019 | 0.44 | 2.04 | 1.43 | 0.97 | 0.45 | 0.89 | 1.06 | 0.63 |
| 2020 | 0.44 | 2.04 | 1.43 | 0.97 | 0.45 | 0.89 | 1.06 | 0.63 |
| 2021 | 0.43 | 2.03 | 1.42 | 0.97 | 0.44 | 0.88 | 1.05 | 0.62 |
| 2022 | 0.43 | 2.03 | 1.42 | 0.96 | 0.44 | 0.88 | 1.05 | 0.62 |
| 2023 | 0.43 | 2.03 | 1.42 | 0.96 | 0.44 | 0.88 | 1.05 | 0.62 |
| 2024 | 0.42 | 2.02 | 1.41 | 0.96 | 0.43 | 0.87 | 1.04 | 0.61 |
| 2025 | 0.42 | 2.02 | 1.41 | 0.95 | 0.43 | 0.87 | 1.04 | 0.61 |

**Table B5-3 - Medium-Low
Coal Price Forecasts
(2000$ Per MMBtu)**

| Medium Low Case | | | Selected State Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | Washington | Oregon | Montana | Idaho | Utah | Wyoming |
| 2000 | 0.51 | 2.11 | 1.65 | 1.09 | 0.71 | 0.00 | 1.39 | 0.81 |
| 2001 | 0.51 | 2.11 | 1.50 | 1.04 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2002 | 0.51 | 2.11 | 1.50 | 1.04 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2003 | 0.51 | 2.11 | 1.50 | 1.04 | 0.52 | 0.96 | 1.13 | 0.70 |
| 2004 | 0.50 | 2.10 | 1.49 | 1.04 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2005 | 0.50 | 2.10 | 1.49 | 1.03 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2006 | 0.50 | 2.10 | 1.49 | 1.03 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2007 | 0.50 | 2.10 | 1.49 | 1.03 | 0.51 | 0.95 | 1.12 | 0.69 |
| 2008 | 0.49 | 2.09 | 1.48 | 1.03 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2009 | 0.49 | 2.09 | 1.48 | 1.02 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2010 | 0.49 | 2.09 | 1.48 | 1.02 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2011 | 0.49 | 2.09 | 1.48 | 1.02 | 0.50 | 0.94 | 1.11 | 0.68 |
| 2012 | 0.48 | 2.08 | 1.47 | 1.02 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2013 | 0.48 | 2.08 | 1.47 | 1.01 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2014 | 0.48 | 2.08 | 1.47 | 1.01 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2015 | 0.48 | 2.08 | 1.47 | 1.01 | 0.49 | 0.93 | 1.10 | 0.67 |
| 2016 | 0.47 | 2.07 | 1.46 | 1.01 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2017 | 0.47 | 2.07 | 1.46 | 1.00 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2018 | 0.47 | 2.07 | 1.46 | 1.00 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2019 | 0.47 | 2.07 | 1.46 | 1.00 | 0.48 | 0.92 | 1.09 | 0.66 |
| 2020 | 0.46 | 2.06 | 1.45 | 1.00 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2021 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2022 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2023 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2024 | 0.46 | 2.06 | 1.45 | 0.99 | 0.47 | 0.91 | 1.08 | 0.65 |
| 2025 | 0.45 | 2.05 | 1.44 | 0.99 | 0.46 | 0.90 | 1.07 | 0.64 |

## Table B5-4 - Medium-High
## Coal Price Forecasts
## (2000$ Per MMBtu)

| **Medium High Case** | | | Selected State Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | Washington | Oregon | Montana | Idaho | Utah | Wyoming |
| 2000 | 0.51 | 2.11 | 1.65 | 1.09 | 0.71 | 0.00 | 1.39 | 0.81 |
| 2001 | 0.52 | 2.12 | 1.51 | 1.05 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2002 | 0.52 | 2.12 | 1.51 | 1.05 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2003 | 0.52 | 2.12 | 1.51 | 1.05 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2004 | 0.52 | 2.12 | 1.51 | 1.06 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2005 | 0.53 | 2.13 | 1.52 | 1.06 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2006 | 0.53 | 2.13 | 1.52 | 1.06 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2007 | 0.53 | 2.13 | 1.52 | 1.06 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2008 | 0.53 | 2.13 | 1.52 | 1.07 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2009 | 0.54 | 2.14 | 1.53 | 1.07 | 0.55 | 0.99 | 1.16 | 0.73 |
| 2010 | 0.54 | 2.14 | 1.53 | 1.07 | 0.55 | 0.99 | 1.16 | 0.73 |
| 2011 | 0.54 | 2.14 | 1.53 | 1.08 | 0.55 | 0.99 | 1.16 | 0.73 |
| 2012 | 0.55 | 2.15 | 1.54 | 1.08 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2013 | 0.55 | 2.15 | 1.54 | 1.08 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2014 | 0.55 | 2.15 | 1.54 | 1.08 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2015 | 0.55 | 2.15 | 1.54 | 1.09 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2016 | 0.56 | 2.16 | 1.55 | 1.09 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2017 | 0.56 | 2.16 | 1.55 | 1.09 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2018 | 0.56 | 2.16 | 1.55 | 1.09 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2019 | 0.56 | 2.16 | 1.55 | 1.10 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2020 | 0.57 | 2.17 | 1.56 | 1.10 | 0.58 | 1.02 | 1.19 | 0.76 |
| 2021 | 0.57 | 2.17 | 1.56 | 1.10 | 0.58 | 1.02 | 1.19 | 0.76 |
| 2022 | 0.57 | 2.17 | 1.56 | 1.11 | 0.58 | 1.02 | 1.19 | 0.76 |
| 2023 | 0.58 | 2.18 | 1.57 | 1.11 | 0.59 | 1.03 | 1.20 | 0.77 |
| 2024 | 0.58 | 2.18 | 1.57 | 1.11 | 0.59 | 1.03 | 1.20 | 0.77 |
| 2025 | 0.58 | 2.18 | 1.57 | 1.11 | 0.59 | 1.03 | 1.20 | 0.77 |

**Table B5-5 - High**
**Coal Price Forecasts**
**(2000$ Per MMBtu)**

| **High Case** | | | Selected State Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | Washington | Oregon | Montana | Idaho | Utah | Wyoming |
| 2000 | 0.51 | 2.11 | 1.65 | 1.09 | 0.71 | 0.00 | 1.39 | 0.81 |
| 2001 | 0.52 | 2.12 | 1.51 | 1.05 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2002 | 0.52 | 2.12 | 1.51 | 1.06 | 0.53 | 0.97 | 1.14 | 0.71 |
| 2003 | 0.53 | 2.13 | 1.52 | 1.06 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2004 | 0.53 | 2.13 | 1.52 | 1.07 | 0.54 | 0.98 | 1.15 | 0.72 |
| 2005 | 0.54 | 2.14 | 1.53 | 1.07 | 0.55 | 0.99 | 1.16 | 0.73 |
| 2006 | 0.54 | 2.14 | 1.53 | 1.07 | 0.55 | 0.99 | 1.16 | 0.73 |
| 2007 | 0.55 | 2.15 | 1.54 | 1.08 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2008 | 0.55 | 2.15 | 1.54 | 1.08 | 0.56 | 1.00 | 1.17 | 0.74 |
| 2009 | 0.56 | 2.16 | 1.55 | 1.09 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2010 | 0.56 | 2.16 | 1.55 | 1.09 | 0.57 | 1.01 | 1.18 | 0.75 |
| 2011 | 0.57 | 2.17 | 1.56 | 1.10 | 0.58 | 1.02 | 1.19 | 0.76 |
| 2012 | 0.57 | 2.17 | 1.56 | 1.10 | 0.58 | 1.02 | 1.19 | 0.76 |
| 2013 | 0.58 | 2.18 | 1.57 | 1.11 | 0.59 | 1.03 | 1.20 | 0.77 |
| 2014 | 0.58 | 2.18 | 1.57 | 1.11 | 0.59 | 1.03 | 1.20 | 0.77 |
| 2015 | 0.59 | 2.19 | 1.58 | 1.12 | 0.60 | 1.04 | 1.21 | 0.78 |
| 2016 | 0.59 | 2.19 | 1.58 | 1.13 | 0.60 | 1.04 | 1.21 | 0.78 |
| 2017 | 0.60 | 2.20 | 1.59 | 1.13 | 0.61 | 1.05 | 1.22 | 0.79 |
| 2018 | 0.60 | 2.20 | 1.59 | 1.14 | 0.61 | 1.05 | 1.22 | 0.79 |
| 2019 | 0.61 | 2.21 | 1.60 | 1.14 | 0.62 | 1.06 | 1.23 | 0.80 |
| 2020 | 0.61 | 2.21 | 1.60 | 1.15 | 0.62 | 1.06 | 1.23 | 0.80 |
| 2021 | 0.62 | 2.22 | 1.61 | 1.15 | 0.63 | 1.07 | 1.24 | 0.81 |
| 2022 | 0.63 | 2.23 | 1.62 | 1.16 | 0.64 | 1.08 | 1.25 | 0.82 |
| 2023 | 0.63 | 2.23 | 1.62 | 1.16 | 0.64 | 1.08 | 1.25 | 0.82 |
| 2024 | 0.64 | 2.24 | 1.63 | 1.17 | 0.65 | 1.09 | 1.26 | 0.83 |
| 2025 | 0.64 | 2.24 | 1.63 | 1.18 | 0.65 | 1.09 | 1.26 | 0.83 |

r:\dw\ww\fifth_plan\push to the final\prepub\appendix b (fuel price forecast)(pp).doc

# Wholesale Electricity Price Forecast

This appendix describes the wholesale electricity price forecast of Fifth Northwest Power Plan. This forecast is an estimate of the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This price represents the marginal cost of electricity and is used by the Council in assessing the cost-effectiveness of conservation and new generating resource alternatives. The price forecast is also used to estimate the cost implications of policies affecting power system composition or operation. A forecast of the future Western Electricity Coordinating Council (WECC) generating resource mix is also produced, as a precursor to the electricity price forecast. This resource mix is used to forecast the fuel consumption and carbon dioxide ($CO_2$) production of the future power system.

The next section describes the base case forecast results and summarizes the underlying assumptions. The subsequent section describes the modeling approach. The final section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions. Costs and prices appearing in this appendix are in year 2000 dollars unless otherwise noted.

## BASE CASE FORECAST

The base case wholesale electricity price forecast uses the Council's medium electricity sales forecast, medium fuel price forecast, average hydropower conditions, the new resource cost and performance characteristics developed for this plan, and the mean annual values of future $CO_2$ mitigation cost, renewable energy production tax credits and renewable energy credits of the portfolio analysis of this plan. These are summarized in Table C-1.

**Table C-1: Summary of assumptions underlying the base case forecast**

| | |
|---|---|
| Hydropower | Average hydropower conditions<br>Linear reduction of available Northwest hydropower by 450 MW 2005 through 2024 |
| Fuel prices | 5th Plan forecast, Medium case |
| Loads | 5th Plan electricity sales forecast, Medium case, adjusted for 150 aMW/yr conservation, 200 aMW Direct Service Industry load and transmission and distribution losses |
| Northwest resources | Resources in service as of Q4 2004<br>Resources under construction as of Q4 2004<br>Retirements scheduled as of Q4 2004<br>75 percent of Oregon and Montana system benefit charge target acquisitions<br>50 percent of demand response potential by 2025 |
| Other WECC resources | Resources in service as of Q1 2003<br>Resources under construction as of Q1 2003<br>Retirements scheduled as of Q1 2003<br>75 percent of state renewable portfolio standard and & system benefit charge target acquisitions<br>50 percent of demand response potential by 2025. |

| | |
|---|---|
| New resource options | 610 MW natural gas-fired combined-cycle gas turbines<br>100 MW wind power plants - prime resource areas<br>100 MW wind power plants - secondary resource areas<br>400 MW coal-fired steam-electric plants<br>425 MW coal gasification combined-cycle plants<br>2x47 MW natural gas-fired simple-cycle gas turbines<br>100 MW central-station solar photovoltaic plants<br>Montana First Megawatts 240 MW natural gas-fired combined-cycle plant<br>Mint Farm 286 MW natural gas-fired combined-cycle plant<br>Grays Harbor 640 MW natural gas-fired combined-cycle plant |
| Inter-regional transmission | 2003 WECC path ratings<br>Scheduled upgrades as of Q1 2003 |
| Carbon dioxide penalty | Washington & Oregon: \$0.87/ton $CO_2$ for 17% of production until exceeded by the mean annual values of the portfolio analysis.<br>Other load-resource zones: The mean annual values of the portfolio analysis |
| Renewable resource incentives | Federal production tax credit at mean annual values of the portfolio analysis<br>Green tag revenue at mean annual values of the portfolio analysis |

The forecast Mid-Columbia trading hub price, levelized for the period 2005 through 2025 is \$36.20 per megawatt-hour. In Figure C-1, the current forecast is compared to the base case ("Current Trends") forecast of the Draft 5th Power Plan (levelized value of \$36.10 per megawatt-hour).

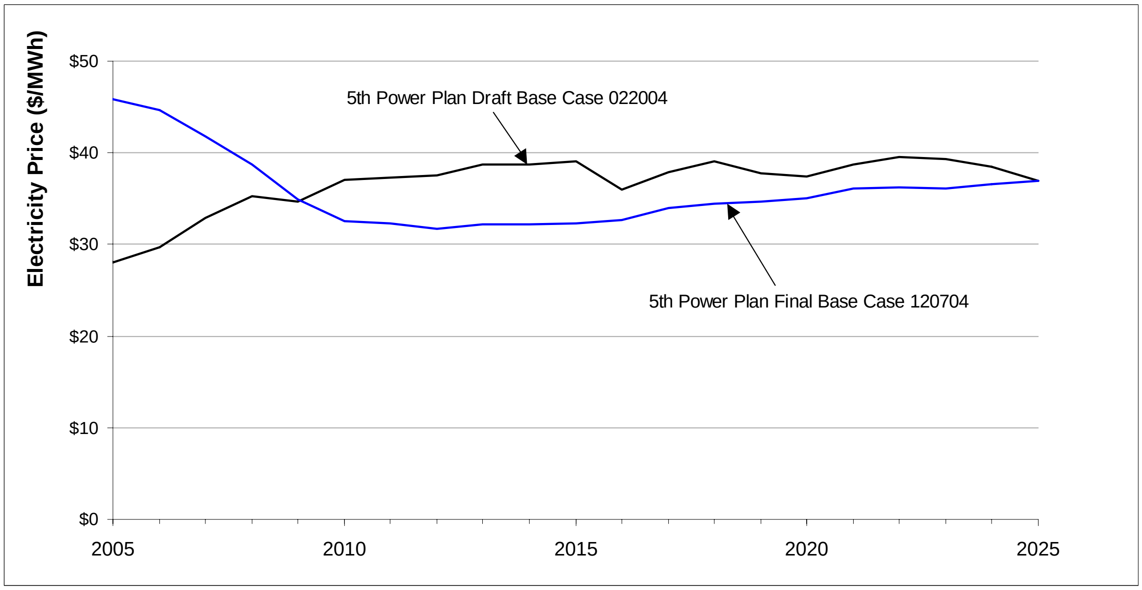



**Figure C-1: Draft and final base case forecasts of average annual wholesale electricity prices at the Mid-Columbia trading hub**

The final forecast prices decline from 2003 highs as gas prices decline, leveling off about 2012 as growing loads exhaust the current generating capacity and new capacity development ensues. Prices slowly increase through the remainder of the planning period under the influence of slowly increasing natural gas prices, new resource additions, declining renewable energy incentives and increasing $CO_2$ penalties. Not included in the forecast are likely episodic price excursions resulting from gas price volatility or poor hydro conditions.

The annual average prices of Figure C-1 conceal important seasonal price variation. Seasonal variation is shown in the plot of monthly average Mid-Columbia prices in Figure C-2. Also plotted in Figure C-2 are monthly average Northwest loads and monthly average Southern California loads. The winter-peaking character of Northwest loads (driven by lighting and heating loads) and the more pronounced summer-peaking character of the Southern California loads (driven by air conditioning and irrigation loads) are evident. A strong winter Mid-Columbia price peak, driven by winter peaking Northwest loads is present throughout the forecast. A secondary summer price peak is also present because spot market prices in the Northwest will follow Southwest prices as long as capacity to transmit electricity south is available on the interties. The summer Mid-Columbia price peak begins to increase in magnitude midway through the planning period as California loads grow relative to Northwest loads. The summer price peak increases the value of summer-peaking efficiency resources such as irrigation efficiency improvements.

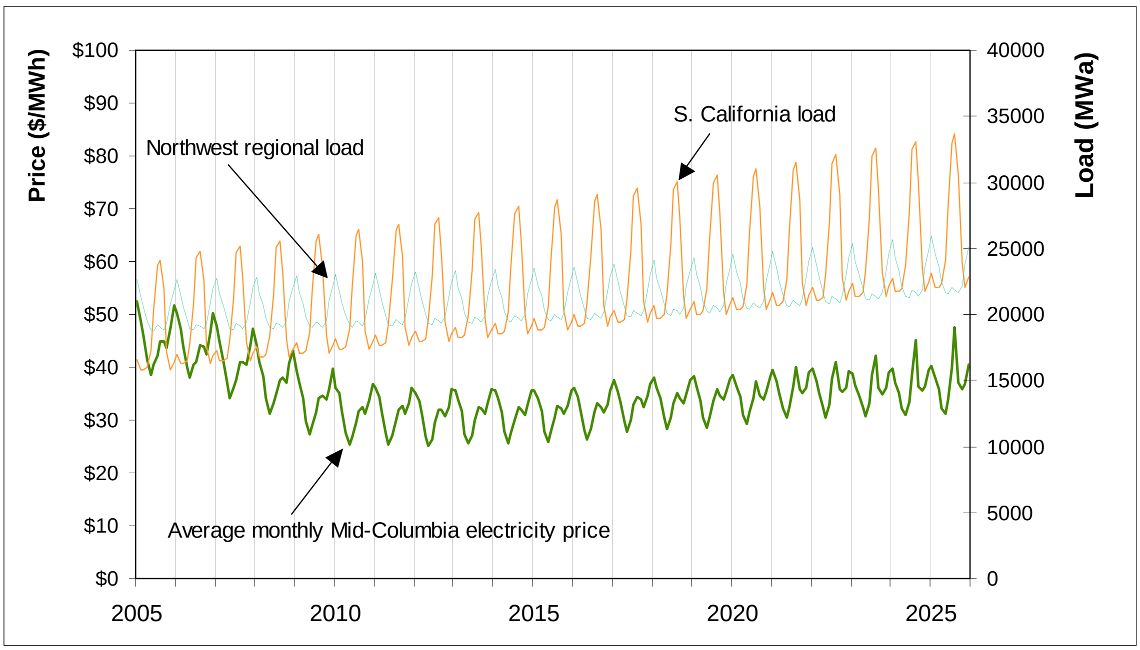



**Figure C-2: Monthly wholesale Mid-Columbia prices compared to Northwest and Southwest load shapes**

Daily variation in prices is significant as well, with implications for the cost-effectiveness of certain conservation measures. Typical daily price variation is shown in Figure C-3 - a snapshot of the hourly Mid Columbia forecast for a summer week.

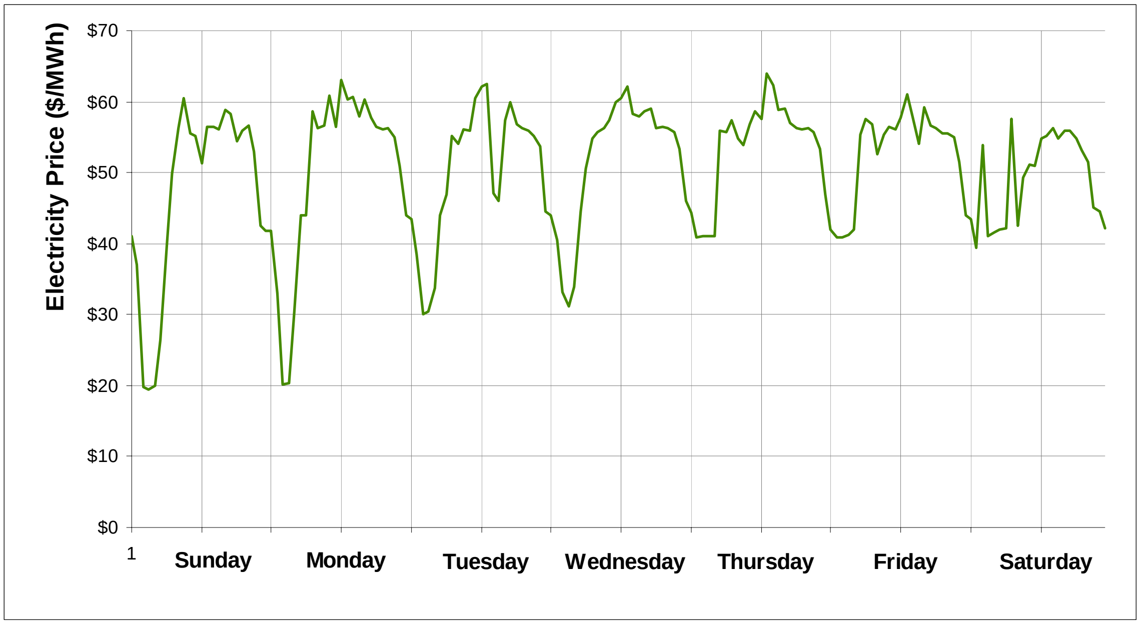



**Figure C-3: Illustrative hourly prices (July 31- August 7, 2005)**

The forecast annual average prices for the Mid-Columbia trading hub and for other Northwest load-resource zones is provided in Table C-1. Monthly and hourly price series are available from the Council on request.

**Table C-1: Forecast annual average wholesale electricity prices for Northwest load-resource zones**

| Year | West of Cascades | Mid-Columbia (Eastside) | S. Idaho | E. Montana |
|---|---|---|---|---|
| 2005 | 45.99 | 45.84 | 45.16 | 44.86 |
| 2006 | 44.84 | 44.68 | 45.16 | 44.86 |
| 2007 | 41.99 | 41.76 | 45.16 | 44.86 |
| 2008 | 38.93 | 38.71 | 45.16 | 44.86 |
| 2009 | 35.11 | 34.94 | 45.16 | 44.86 |
| 2010 | 32.65 | 32.52 | 45.16 | 44.86 |
| 2011 | 32.42 | 32.31 | 45.16 | 44.86 |
| 2012 | 31.85 | 31.75 | 45.16 | 44.86 |
| 2013 | 32.27 | 32.17 | 45.16 | 44.86 |
| 2014 | 32.25 | 32.15 | 45.16 | 44.86 |
| 2015 | 32.37 | 32.28 | 45.16 | 44.86 |
| 2016 | 32.76 | 32.66 | 45.16 | 44.86 |
| 2017 | 34.07 | 33.99 | 45.16 | 44.86 |
| 2018 | 34.54 | 34.46 | 45.16 | 44.86 |
| 2019 | 34.74 | 34.67 | 45.16 | 44.86 |
| 2020 | 35.12 | 35.05 | 45.16 | 44.86 |
| 2021 | 36.16 | 36.08 | 45.16 | 44.86 |
| 2022 | 36.25 | 36.18 | 45.16 | 44.86 |
| 2023 | 36.10 | 36.05 | 45.16 | 44.86 |
| 2024 | 36.58 | 36.52 | 45.16 | 44.86 |
| 2025 | 37.06 | 36.99 | 45.16 | 44.86 |

The base case forecast resource mix for the interconnected Western Electricity Coordinating Council (WECC) area is shown in Figure C-4. Factors affecting resource development through the 2005-2025 period include load growth, natural gas prices, generating resource technology improvement, continued renewable resource incentives and increasing probability of carbon dioxide production penalties. Principal additions between 2005 and 2025 include approximately 4600 megawatts of renewable resources resulting from state renewable portfolio standards and system benefit charges, 17,000 megawatts of combined-cycle plant, 20,000 megawatts of steam coal capacity, 22,000 megawatts of wind capacity and 9000 megawatts of coal gasification combined-cycle plant. Retirements include 1650 MW of steam coal, 1400 MW of gas combined-cycle and 1400 MW of gas steam units. The 2025 capacity mix includes 33 percent natural gas, 25 percent hydropower, 24 percent coal and 11 percent intermittent renewables (wind and solar). Not shown in the figure is about 9,000 megawatts of demand response capability assumed to be secured between 2007 and 2025.

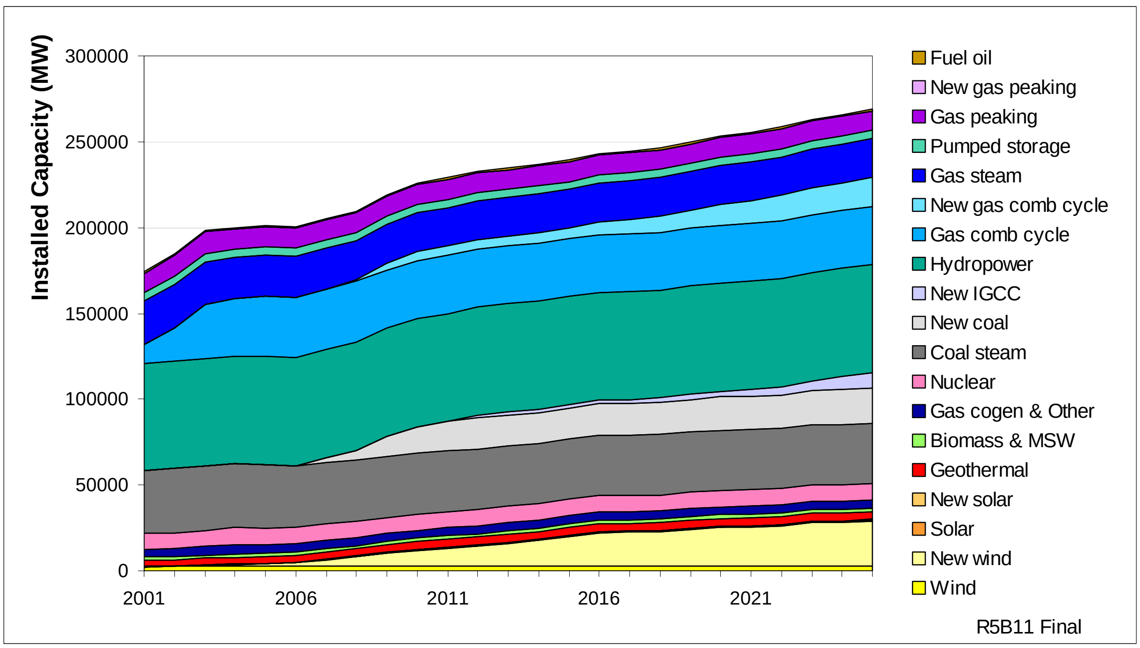



**Figure C-4: Base case WECC resource mix**

The Northwest resource mix is shown in Figure C-5. About 960 megawatts of renewables funded by state system benefit charges (modeled as wind) and 2900 additional megawatts of new, market-driven wind power are added during the period 2005-25 in addition to the 399 MW Port Westward combined-cycle plant, currently under construction. No capacity is retired. The regional capacity mix in 2025 includes 67 percent hydropower, 13 percent natural gas, 9 percent wind and 8 percent coal. Not shown in the figure is about 1,900 megawatts of demand response capability assumed to be secured between 2007 and 2025. Because the capacity addition logic used for this forecast uses deterministic fuel prices, loads, renewable production credits, $CO_2$ penalties and other values affecting resource cost-effectiveness, the resulting resource additions differ somewhat from the recommendations resulting from the more sophisticated risk analysis described in Chapter 7 of the plan.

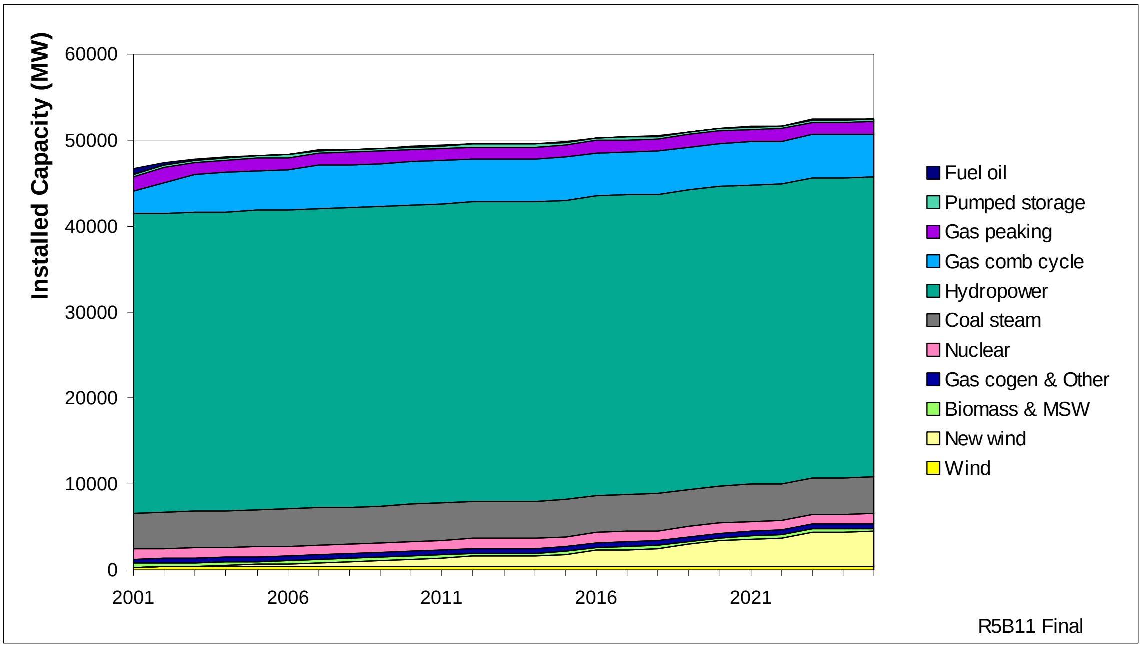



**Figure C-5: Base case Pacific Northwest resource mix**

Other base case results are summarized in Table C-3. Further detail can be found in the workbook PLOT R5B11 Final Base 012705.xls, posted in the Council's website dropbox.

## APPROACH

The Council forecasts wholesale electricity prices using the AURORA$^{xmp®}$ electricity market model. Electricity prices are based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. A forecast is developed using the two-step process illustrated in Figure C-6. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using the AURORA$^{xmp®}$ long-term resource optimization logic. This is an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, operation, maintenance and fuel including a return on the developer's investment and a dispatch premium. This step results in a future resource mix such as depicted for the base case in Figure C-4.

The electricity price forecast is developed in the second step, in which the mix of resources developed in the first step is dispatched on an hourly basis to serve forecast loads. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the forecast price.

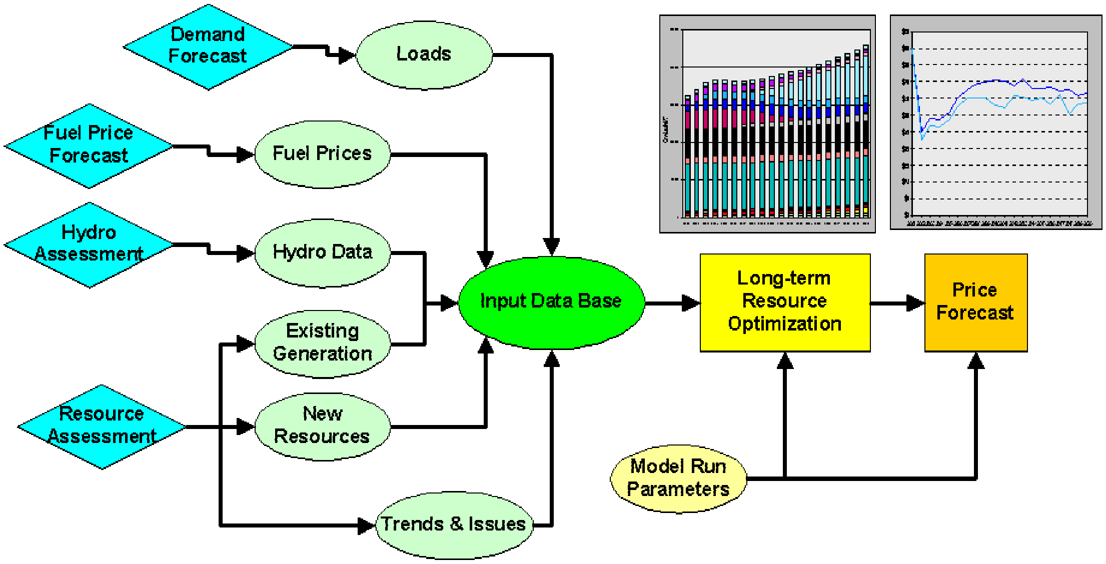



**Figure C-6: Price forecasting process**

As configured by the Council, AURORA$^{xmp®}$ simulates power plant dispatch in each of 16 load-resource zones comprising the WECC electric reliability area (Figure C-7). These zones are defined by transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource zone may be served by native generation, curtailment, or by imports from other load-resource zones if economic, and if transmission transfer capability is available.

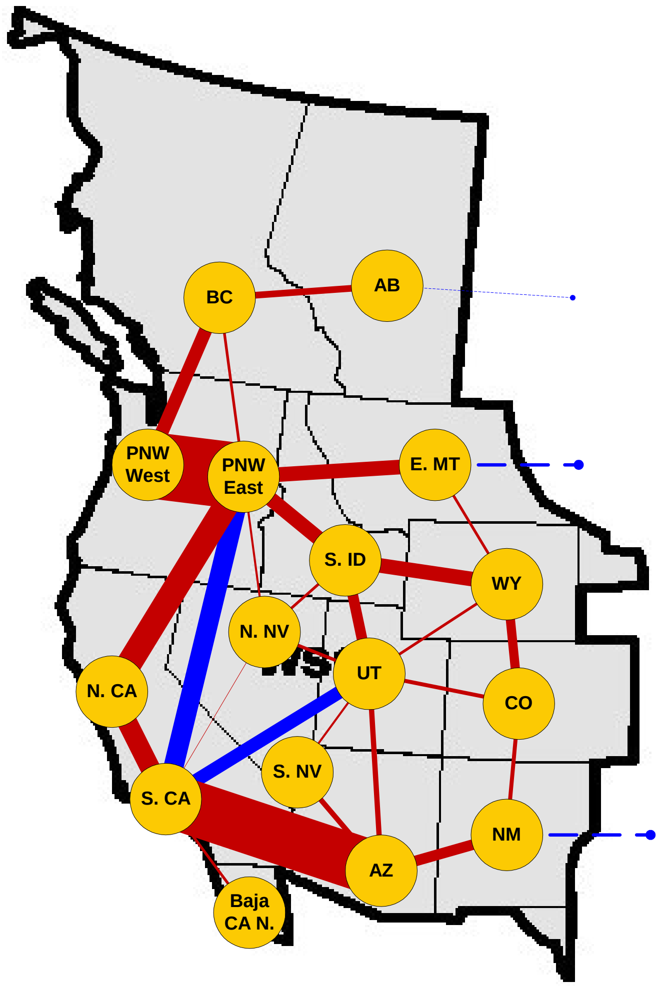



**Figure C-7: Load-resource zones**

## DATA, ASSUMPTIONS AND SENSITIVITY ANALYSES

The data and assumptions underlying the electricity price forecast are developed by the Council with the assistance of its advisory committees (Appendix C-1). The base forecast is an expected value forecast using the medium case electricity sales forecast, the medium case forecast of fuel prices and average water conditions. Though possible future episodes of fuel price and hydropower volatility are not specifically modeled, water conditions and fuel prices are adjusted to compensate for the biasing effect of volatility on electricity prices. The base case forecast uses the mean annual values of federal renewable production tax credits, renewable energy credit revenues and possible future carbon dioxide penalties from the portfolio risk analysis.

### Electricity Loads

The Council's medium case electricity sales forecast is the basis for the base case electricity price forecast for Northwest load-resource zones. Transmission and distribution losses are added and the effects of price-induced and programmatic conservation deducted to produce a load forecast. In the medium-case forecast, Northwest loads, including eastern Montana are forecast to grow at an average annual rate of approximately 0.7 percent per year from 20,875 average megawatts in 2005 to 23,850 average megawatts in 2025. Direct Service Industry loads average 200 megawatts in the medium case.

Total WECC load is forecast to grow at an annual average rate of 1.7 percent, from about 94,800 average megawatts in 2005 to 132,100 average megawatts in 2025. Most load-resource zones outside the Northwest are forecast to see more rapid load growth than Northwest areas (Table C-2). The approach used to forecast loads for load-resource zones outside the Northwest was to calculate future growth in electricity demand as the historical growth rate of electricity use per capita times a forecast of population growth rate for the area. Exceptions to this method were California, where forecasts by the California Energy Commission were used, and the Canadian provinces, where load forecasts are available from the National Energy Board.

**Table C-2: Base loads and medium case forecast load growth rates**[a]

| Load-resource zone | 2005 (Average Megawatts) | 2025 (Average Megawatts) | Average Annual Load Growth, 2005-2025 |
|---|---|---|---|
| PNW Eastside (WA & OR E. of Cascade crest, Northern ID & MT west of Continental Divide. | 4695 | 5341 | 0.6 percent |
| PNW Westside (WA & OR W. of Cascade crest) | 12832 | 14661 | 0.7 percent |
| Southern Idaho (~IPC territory) | 2518 | 3022 | 0.9 percent |
| Montana E. (east of Continental Divide) | 830 | 829 | 0.0 percent |
| Alberta | 6023 | 8489 | 1.6 percent |
| Arizona | 8513 | 13867 | 1.4 percent |
| Baja California Norte | 1117 | 1883 | 2.6 percent |
| British Columbia | 7798 | 10199 | 1.4 percent |
| California N. (N. of Path 15) | 13842 | 18794 | 1.5 percent |
| California S. (S. of Path 15) | 18431 | 25686 | 1.7 percent |
| Colorado | 6011 | 9498 | 2.3 percent |
| Nevada N. (~ SPP territory) | 1294 | 1941 | 2.0 percent |
| Nevada S. (~ NPC territory) | 2586 | 4466 | 2.8 percent |
| New Mexico | 3099 | 5670 | 3.1 percent |
| Utah | 3256 | 5702 | 2.7 percent |
| Wyoming | 1814 | 2046 | 0.6 percent |
| **Total** | **94847** | **132094** | **1.7 percent** |

a) Load is forecast sales plus 8 percent transmission and distribution loss.

Sensitivity studies were run using the Council's medium-low and medium-high case electricity sales forecast to assess the implications of long-term load growth uncertainty on electricity prices and resource development. Growth rates for load-resource zones outside the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the percentile growth rate differences between the Northwest medium case (0.7%/yr) and medium-low case (0.1%/yr) and medium-high case (1.3%/yr), respectively.

As expected, the faster load growth of the medium-high load growth case result in higher electricity prices throughout the forecast period (Figure C-8). Beginning about 2017, the medium-high case prices climb rapidly away from the base case prices. This appears to result from accelerated development of natural gas combined-cycle plants at this time. It is likely that gas is selected over coal because of increasing $CO_2$ mitigation cost. Levelized Mid-Columbia prices are $37.70 per megawatt-hour, 4 percent higher than the base case.

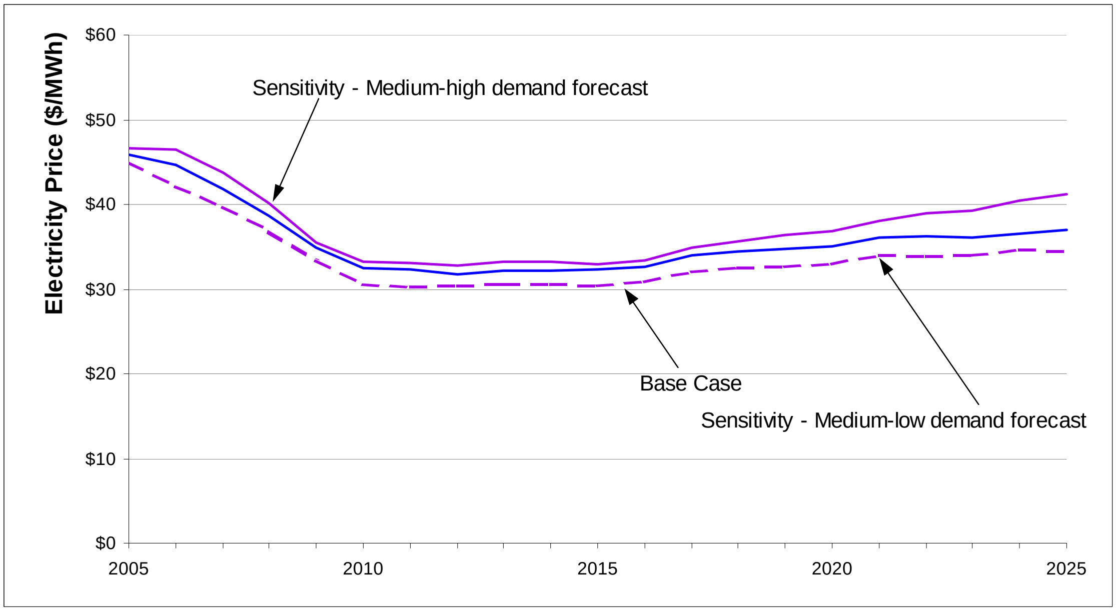



**Figure C-8: Sensitivity of Mid-Columbia electricity price to load growth uncertainty**

The medium-low case results in consistently lower Mid-Columbia prices (Figure C-8). Levelized Mid-Columbia prices are $34.30 per megawatt-hour, 5 percent lower than the base case.

Other results of the load sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final MLDmd 033005.xls, PLOT R5B11 Final MHDmd 041005.xls, posted in the Council's website dropbox.

## Fuel Prices

The Council's medium case fuel price forecast is used for the base case electricity price forecast. Coal prices are based on forecast Western mine-mouth coal prices, and natural gas prices are based on a forecast of U.S. natural gas wellhead prices. Basis differentials are added to the base prices to arrive at delivered fuel prices for each load-resource zone. Natural gas prices are further adjusted for seasonal variation. For example, the price of natural gas delivered to a power plant located in western Washington or Oregon is based on the annual average U.S. wellhead price forecast, adjusted by price differentials between wellhead and Henry Hub (Louisiana); Henry Hub and AECO hub (Alberta); AECO and (compressor) Station 2, British Columbia; and finally, Station 2 and western Washington and Oregon. A monthly adjustment is applied to the AECO - Station 2 differential. The fuel price forecasts and derivation of load-resource area prices are more fully described Appendix B.

In the medium case, the price of Western mine-mouth coal is forecast to hold at $0.51 per million Btu from 2005 through 2025 (constant 2000$). Average distillate fuel oil prices are forecast to stabilize at $6.58 by 2010, following a decline from $7.15 per million Btu in 2005. Price-driven North American exploration and development, increasing liquefied natural gas imports and demand destruction are expected to slowly force down average annual U.S. wellhead natural gas prices from $5.30 per million Btu in 2005 to a low of $3.80/MMBtu in 2015. The annual average price is then forecast to then rise slowly to $4.00 per million Btu in 2025 (2000$), capped by the expected cost of landed liquefied natural gas.

Forecast medium-case delivered prices for selected fuels are plotted in Figure C-9. Fuel prices are shown in Figure C-9 as fully variable (dollars per million Btu) to facilitate comparison. However, the price of delivered coal and natural gas is modeled as a fixed (dollars per kilowatt per year) and a variable (dollars per million Btu) component to differentiate costs, such as pipeline reservation costs that are fixed in the short-term.

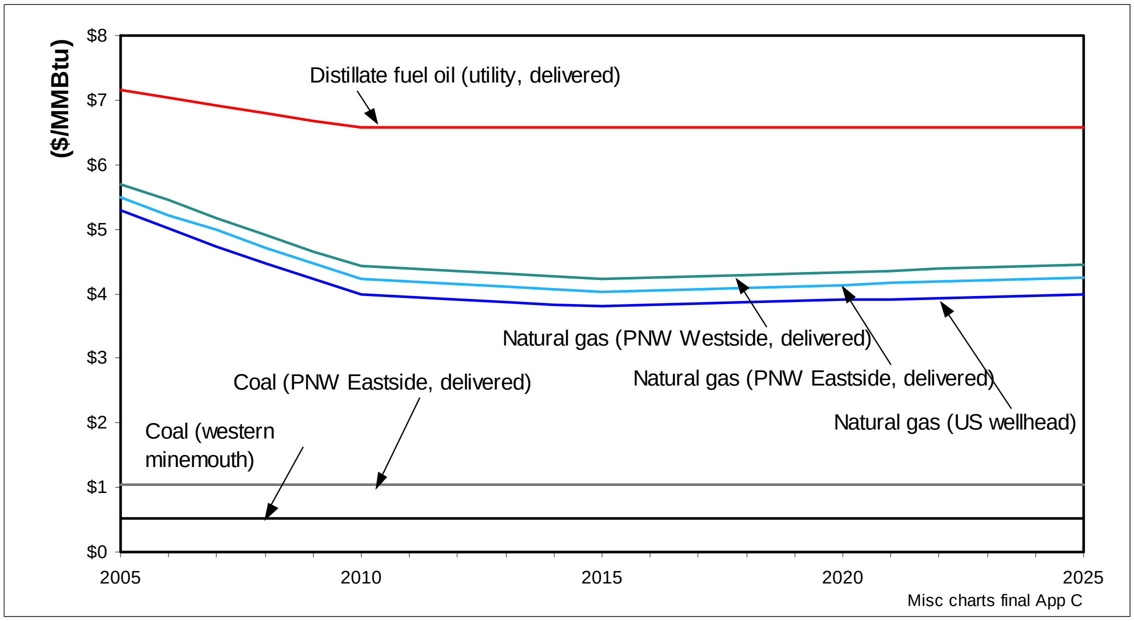



**Figure C-9: Forecast prices for selected fuels - Medium Case**

Sensitivity analyses were run using the Council's high case and low case fuel price forecasts to examine the effects of higher or lower fuel prices on the future resource mix and electricity prices. The high case and the low case fuel price forecasts for wellhead gas and minemouth coal are compared to the medium case forecasts in Figure C-10.

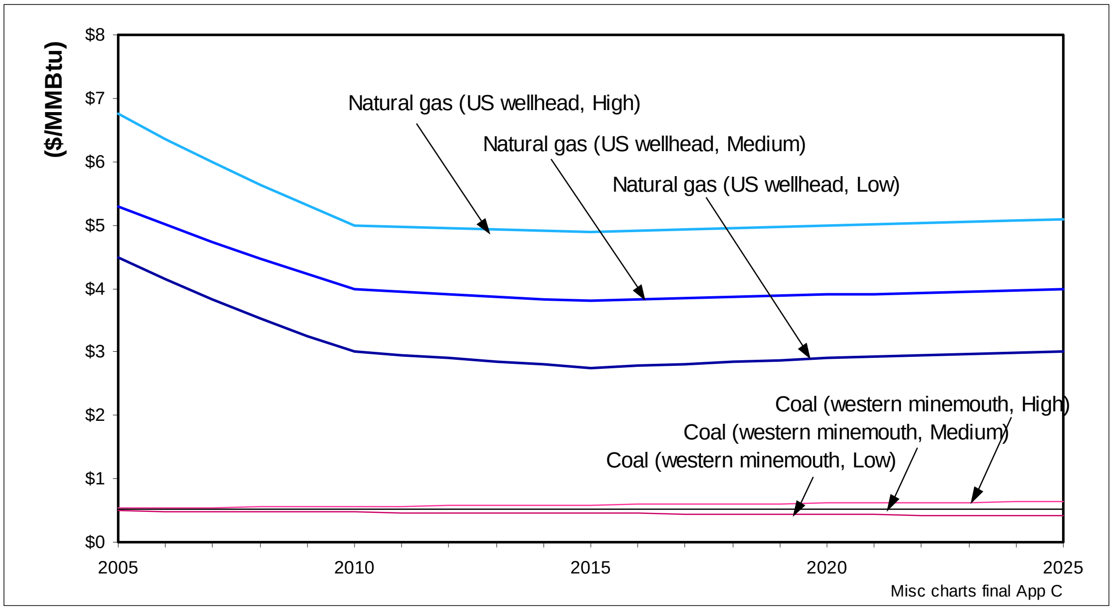



**Figure C-10: Natural gas and coal price forecast cases**

The low fuel price forecast results in levelized Mid-Columbia electricity prices of $29.80 per megawatt-hour, 18 percent lower than the base case. The lower price is evident throughout the forecast period, possibly as a manifestation of continued reliance on gas-fired combined-cycle power plants (Figure C-11). The 2025 resource mix (Table C-3) shows a shift away from new coal and wind to new gas-fired units. Also evident in Table C-3 is the substantial reduction in $CO_2$ production associated with the greater penetration of natural gas. If this were intended to be a scenario rather than a sensitivity case, the higher loads resulting from lower prices would offset a portion of the potential $CO_2$ reduction.

The high fuel price forecast results in levelized Mid-Columbia electricity prices of $39.60 per megawatt-hour, 9 percent higher than the base case. Prices are substantially higher in the near-term, but moderate toward base case values by 2015 as new coal-fired power plants supplement existing gas-fired capacity (Figure C-11). The 2025 resource mix (Table C-3) shows a strong shift to new conventional coal and IGCC plants and wind in lieu of new gas-fired capacity. Towards the end of the forecast period, increasing $CO_2$ mitigation costs result in electricity prices again rising above base case values.

Other results of the fuel price sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final LoFuel 031705.xls, PLOT R5B11 Final HiFuel 031605.xls, posted in the Council’s website dropbox.

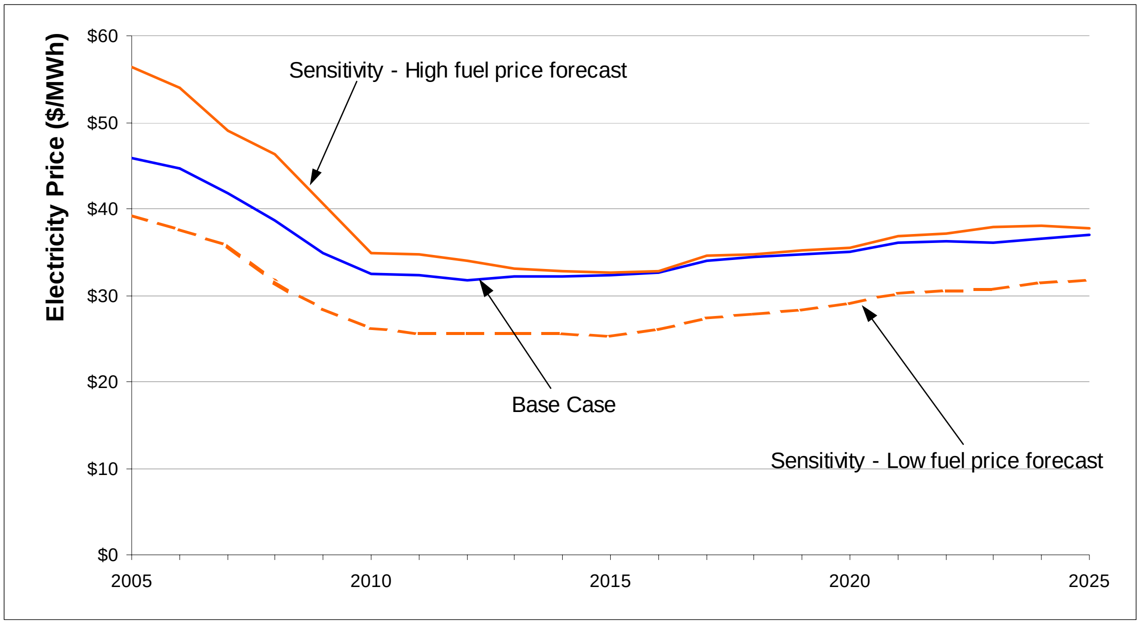



**Figure C-11: Sensitivity of Mid-Columbia electricity price to fuel price uncertainty**

## Demand Response

Demand response is a change in the level or quality of service that is voluntarily accepted by the consumer, usually in exchange for payment. Demand response can shift load from peak to off-peak periods and reduce the cost of generation by shifting the marginal dispatch to more efficient or otherwise less-costly units. Demand response may also be used to reduce the absolute amount of energy consumed to the extent that end-users are willing to forego net electricity consumption in return for compensation. The attractiveness of demand response is not only its ability to reduce the overall cost of supplying electricity; it also rewards end users for reducing consumption during times of high prices and possible supply shortage. Demand response also offers many of the environmental benefits of conservation.

Though the understanding of demand response potential remains sketchy, preliminary analysis by the Council suggests that ultimately up to 16 percent of load might be offset at a cost of $50 to $400 per megawatt-hour through various forms of time-of-day pricing and negotiated agreements. For the base case forecast, we assume that 50 percent of this potential is secured, beginning in 2007 and ramping up to 2025. Similar penetration is assumed throughout WECC.

## Existing Generating Resources

The existing power supply system modeled for the electricity price forecast consisted of the projects within the WECC interconnected system in service and under construction as of the first quarter of 2003. Three Northwest gas combined-cycle power plants for which construction was suspended, Grays Harbor, Mint Farm and Montana First Megawatts were included as new generating resource options. Projects having announced retirement dates were retired as scheduled.

## New Generating Resource Options

When running a capacity expansion study, AURORA$^{xmp®}$ adds capacity when the net present value cost of adding a new unit is less than the net present market value of the unit. Because of study run time considerations, the number of available new resource alternatives is limited to those possibly having a significant effect on future electricity prices. Some resource alternatives such as gas combined-cycle plants and wind are currently significant and likely to remain so. Others, such as new hydropower or various biomass resources, are unlikely to be available in sufficient quantity to significantly influence future electricity prices. Some, such as coal gasification combined-cycle plants or solar photovoltaics do not currently affect power prices, but may so as the technology develops and costs decline. Resources such as new generation nuclear plants or wave energy plants were omitted because they are unlikely to be commercially mature during the forecast period. Others, such as gas-fired reciprocating generator sets were omitted because they are not markedly different from simple-cycle gas turbines with respect to their effect on future electricity prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, wind power, coal-fired steam-electric power plants, coal gasification combined-cycle plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

### Natural gas-fired combined cycle power plants

The high thermal efficiency, low environmental impact, short construction time and excellent operating flexibility of natural gas-fired combined-cycle plants lead to this technology becoming the “resource of choice” in the 1990s. In recent years, high natural gas prices have dimmed the attractiveness of combined-cycle plants and many projects currently operate at low load factors. Though technology improvements are anticipated to help offset high natural gas prices, the future role of this resource is sensitive to natural gas prices and global climate change policy. Higher gas prices could shift development to coal or windpower. More stringent carbon dioxide offset requirements might favor combined-cycle plants because of their proportionately lower carbon dioxide production. The representative natural gas combined-cycle power plant used for this forecast is a 2x1 (two gas turbines and one steam turbine) plant of 540 megawatts of baseload capacity plus 70 megawatts of power augmentation (duct-firing) capacity.

### Wind power plants

Improved reliability, cost reduction, financial incentives and emerging interest in the hedge value of wind with respect to gas prices and greenhouse gas control policy have moved wind power from niche to mainstream over the past decade. The cost of wind power (sans financial incentives) is currently higher that that from gas combined-cycle or coal plants, but is expected to decline to competitive levels within several years. The future role of wind is dependent upon gas price, greenhouse gas policy, continued technological improvement, the cost and availability of transmission and shaping services and the availability of financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is expectation that coal may be subject to future $CO_2$ penalties. At current costs, it is infeasible to extend transmission more than several miles to integrate a wind project with the grid. This limits the availability of wind to prime resource areas close to the grid. As wind plant costs decline, feasible interconnection distances will extend, expanding wind power potential. Two cost blocks of wind in 100 MW plant increments were defined for this study - a lower cost block representing good wind resources and low shaping costs, and a higher cost block representing the next phase of wind development with somewhat less favorable wind (lower capacity factor) and higher shaping costs.

## Coal-fired steam-electric power plants

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, relatively low fuel prices, improvements in technology and concerns regarding future natural gas prices have repositioned coal as a potentially economically attractive new generating resource. Conventional steam-electric technology would likely be the coal technology of choice in the near-term. Supercritical steam technology is expected to gradually penetrate the market and additional control of mercury emissions is likely to be required. The representative new coal-fired power plant defined for this forecast is a 400-megawatt steam-electric unit. Costs and performance characteristics simulate a gradual transition to supercritical steam technology over the planning period.

## Coal-gasification combined-cycle power plants

Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation. This improves fuel use efficiency, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers. A 425-megawatt coal-gasification combined-cycle power plant without CO2 separation and sequestration was modeled for the price forecast.

## Natural gas-fired simple-cycle gas turbine generators

Gas turbine generators (simple-cycle gas turbines), reciprocating engine-generator sets, supplementary (duct) firing of combined-cycle plants are potentially cost-effective means of supplying peaking and reserve power needs. As described earlier, the Council also views demand response as a promising approach to meeting peaking and reserve power needs. Supplementary (“duct”) firing of gas combined-cycle plants can also help meet peaking or reserve needs at low cost and is included in the generic combined-cycle plant described above. Additional requirements can be met by simple-cycle gas turbine or reciprocating generator sets. From a modeling perspective, the cost and performance of gas-fired simple-cycle gas turbines and gas-fired reciprocating engine-generator sets are sufficiently similar that only one need be modeled. The Council chose to model a twin-unit (2 x 47 megawatt) aeroderivative simple-cycle gas turbine generator set.

## Central-station solar photovoltaics

Solar power is one of the most potentially attractive and abundant long-term power supply alternatives. Economical small-scale applications of solar photovoltaics are currently found throughout the region where it is costly to secure grid service, however for bulk, grid-connected supply, solar photovoltaics are currently much more expensive than other bulk supply alternatives. Because of the potential for significant cost reduction, the Council included a 100 MW central-station solar photovoltaic plant as a long-term bulk power generating resource alternative.

The cost and performance characteristics of these generating resource alternatives are further described in Chapter 5 and Appendix I.

## Transmission

Transfer ratings between load-resource zones are based on the 2003 WECC path ratings plus scheduled upgrades to Path 15 between northern and southern California (since completed) and scheduled upgrades between the Baja California and southern California.

## Renewable Energy Production Incentive

Federal, state and local governments for many years have provided incentives to promote various forms of energy production, including research and development grants and favorable tax treatment. A federal incentive that significantly affects the economics of renewable resource development is the renewable energy production tax credit (PTC) and the companion renewable energy production incentive (REPI) for tax-exempt entities. Enacted as part of the 1992 Energy Policy Act, and originally intended to help commercialize wind and certain biomass technologies, these incentives have been repeatedly renewed and extended, and currently amount to approximately $13 per megawatt hour (2004 dollars) when levelized over the life of a project. The incentive expired in at the end of 2003 but, in September 2004, was extended to the end of 2005, retroactive to the beginning of 2004. In addition, the scope of qualifying facilities was extended to forms of biomass, geothermal, solar and certain other renewable resources not previously qualifying. The long-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as above-market resource costs are reduced. In addition, federal budget constraints may eventually force reduction or termination of the incentives. However, the incentives remain politically popular, as they encourage development that produces rural property tax revenues and revenue for local landowners on whose land wind turbines are sited. Moreover, the incentives serve as a crude carbon dioxide control mechanism in the absence of more comprehensive federal climate change policy.

Because of these uncertainties, future federal renewable energy production incentive was modeled as a stochastic variable in the portfolio risk analysis, as described in Chapter 6. The mean annual value from the portfolio risk analysis was used for the base case electricity price forecast and for all sensitivity cases (Figure C-12). Because of practical considerations, state and local financial incentives, such as sales and property tax exemptions, were not modeled.

## Renewable Energy Credits

Power from renewable energy projects commands a market premium, manifested in the form of renewable energy credits (RECs, or “green tags”). The REC market is driven by the demand for green power products, the nascent demand for $CO_2$ offsets and by the demand for resources to meet state renewable portfolio standard obligations. The current market value of green tags for recently-developed windpower is reported to be $3 to $4 per megawatt-hour. Solar power commends higher tag prices and tag values for hydro, biomass and geothermal power are generally lower. Power from new projects commands higher tag values than that from existing projects. Future REC revenues were modeled as a stochastic variable in the portfolio risk analysis as described in Chapter 6. The mean annual REC value from the portfolio risk analysis (Figure C-12) was used for both wind and solar power in the base and sensitivity cases.

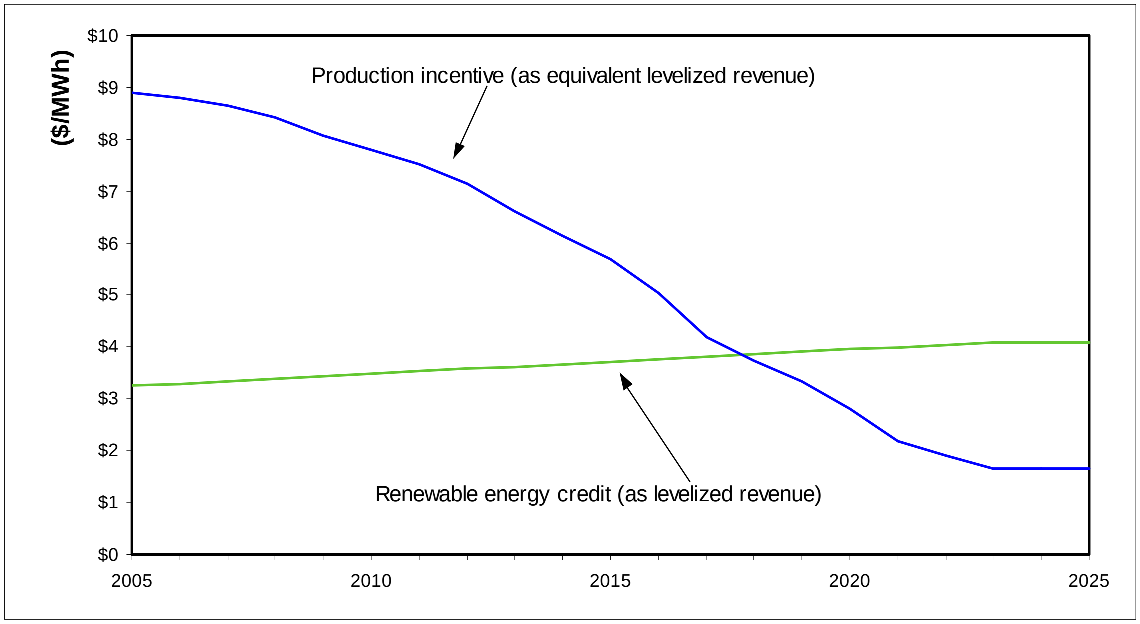



**Figure C-12: Renewable energy incentives**

## Global Climate Change Policy

In the absence of federal initiatives, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Since 1997, Oregon has required mitigation of 17 percent of the carbon dioxide production of new power plants. Washington, in 2004 adopted $CO_2$ mitigation requirements for new fossil power plants exceeding 25 megawatts capacity. In Montana, the developer of the natural gas-fired Basin Creek Power Plant has agreed to mitigate $CO_2$ production to the Oregon requirements. California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Though it appears likely that $CO_2$ production from power generation facilities will be subject to increasing regulation over the period of this plan, the nature and timing of future controls is highly uncertain. For this reason, $CO_2$ mitigation costs were modeled in the portfolio risk analysis as a stochastic carbon tax. The probabilities and distributions used to derive the carbon tax for the portfolio analysis are described in Chapter 6. In the base case electricity price forecast, the mean annual value of the carbon tax from the portfolio risk analysis is applied to both existing and new generating resources. Unlike the portfolio analysis, the current Oregon mitigation requirements are applied to new resources developed in Washington or Oregon until this value is exceeded by the mean annual values from the portfolio analysis (Figure C-13).

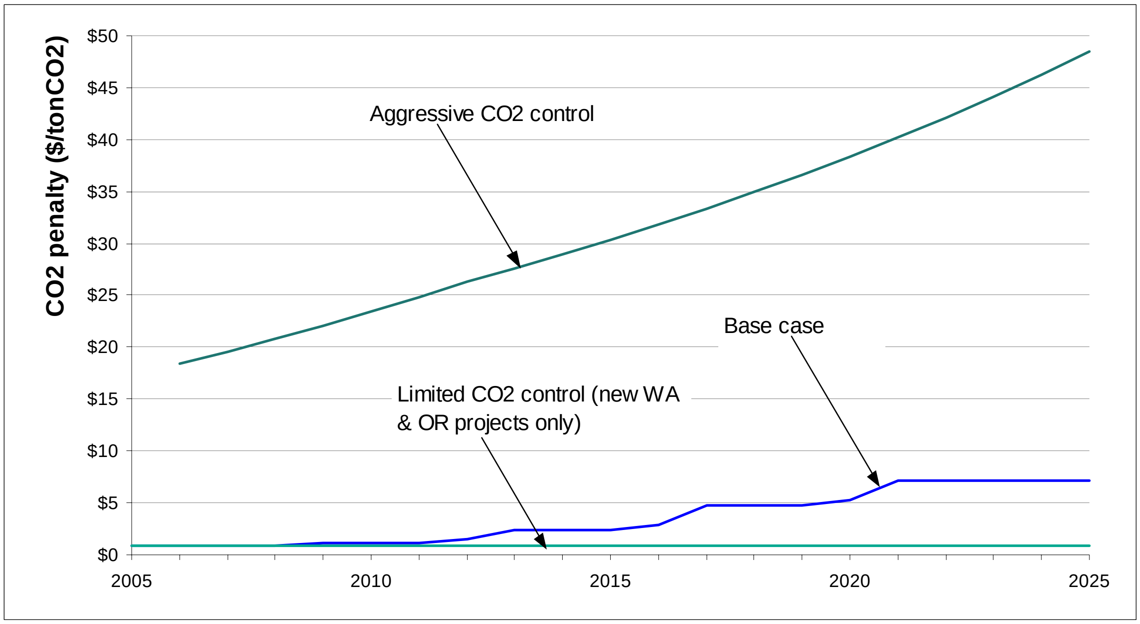



**Figure C-13: $CO_2$ mitigation cost (as carbon tax)**

Because of uncertainties regarding future $CO_2$ regulation, two sensitivity analyses were run. A limited $CO_2$ control case assumed that $CO_2$ mitigation continues to be required only in Oregon and Washington at a cost of $0.87 per ton $CO_2$ (approximately the current Oregon fixed payment option). Compared to the base case, this shifts future resource development from wind and natural gas combined-cycle plants to conventional and gasified coal (Table C-3). Additional older gas steam capacity is retired. The levelized Mid-Columbia price declines by 6 percent to $33.90 per megawatt-hour (Figure C-14). The most significant price reduction is experienced in the longer-term as the resource mix shifts from more expensive natural gas capacity to less expensive coal (Figure C-14). The additional new fossil capacity leads to a larger 2025 WECC system average $CO_2$ production factor of 0.576 lb$CO_2$/kWh, 14 percent greater than that of the base case value of 0.507 lb $CO_2$/kWh (Figure C-15). Cumulative WECC $CO_2$ production for the period 2005-25 increases by 7 percent.

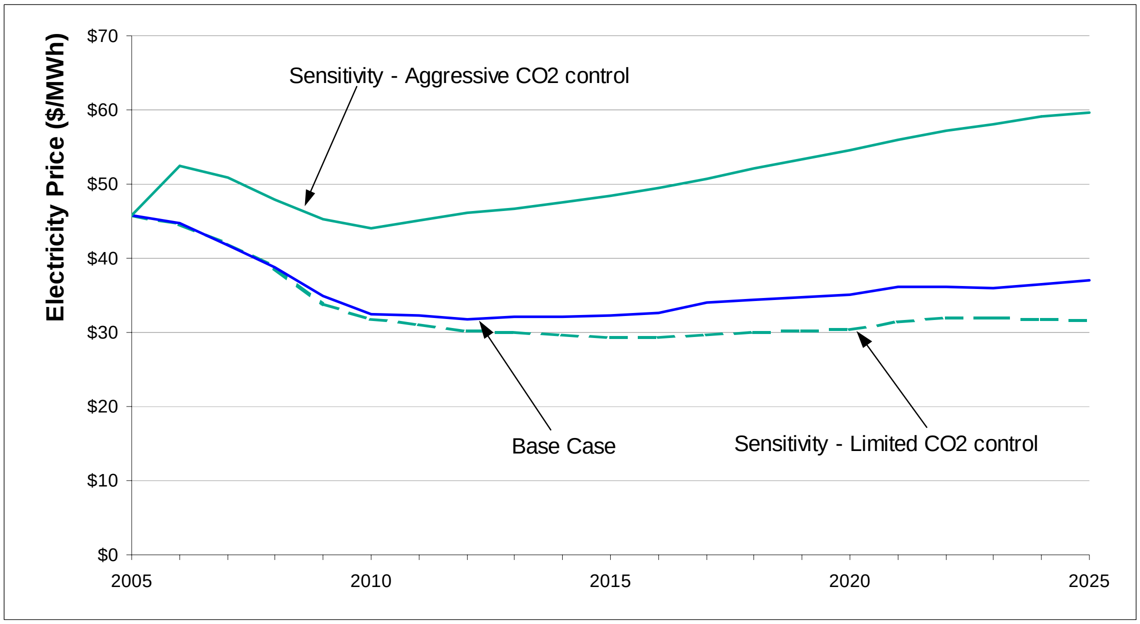



**Figure C-14: Sensitivity of electricity price forecast to $CO_2$ mitigation cost**

An aggressive $CO_2$ control effort was modeled by approximating the nationwide cap and trade program proposed in the McCain-Lieberman Climate Stewardship Act. McCain-Lieberman would implement capped and tradable emissions allowances for $CO_2$ and other greenhouse gasses. Reduction requirements would apply to large commercial, industrial and electric power sources. The proposal rejected by the Senate in a 43-55 vote in 2003 would have capped allowances at 2000 levels by 2010 and 1990 levels in 2016.

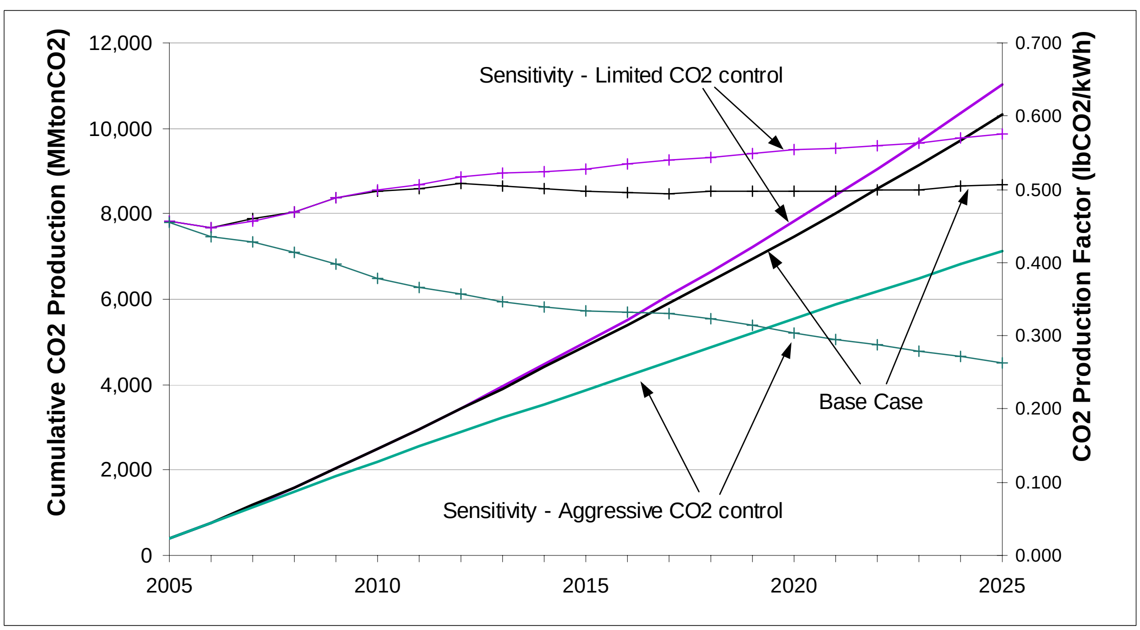



**Figure C-15: Sensitivity of forecast WECC $CO_2$ production to $CO_2$ mitigation cost**

The aggressive $CO_2$ control sensitivity case is based on the assumed enactment of federal regulation similar to the McCain-Lieberman proposal in 2006, with the year 2000 cap in effect in 2012. Model limitations require $CO_2$ mitigation cost to be treated as a carbon tax on fuel use rather than as a true cap and trade system. In this case, fuel carbon for existing and new projects is taxed at the equivalent of a forecast cost of $CO_2$ allowances required to achieve the proposed McCain-Lieberman cap[1]. The allowance costs needed to achieve the targeted reductions of the McCain-Lieberman proposal are highly uncertain but were the subject of a Massachusetts Institute of Technology (MIT) analysis[2]. The sensitivity study was based on the forecast $CO_2$ allowance costs of Case 5 of the MIT study, shifted back two years to coincide with the assumed 2012 Phase I implementation date. A market in banked allowances was assumed to develop on enactment in 2006 so any subsequent reduction in fuel carbon consumption is valued at an opportunity cost equivalent to the discounted forecast 2012 allowance cost. Oregon and Washington were assumed to continue their current mitigation standards at $0.87 per ton through 2006.

These assumptions result in a significant shift in the future resource mix compared to the base case. Wind and gas combined-cycle resource development is accelerated and additions of bulk solar photovoltaics appear near the end of the forecast. About 6 percent of existing coal capacity and 17 percent of existing gas steam capacity is retired over the forecast period. New coal development is entirely absent (Table C-3). The levelized forecast Mid-Columbia price is $50.10 per megawatt-hour, 38 percent higher than the base case value. Prices increase almost immediately, in 2006 because of the opportunity cost of bankable $CO_2$ allowances (Figure C-14). The assumed carbon tax is effective in reducing $CO_2$ production. The shift from coal and less efficient gas-fired capacity to wind, solar and more efficient gas capacity rapidly reduces the CO2 production factor. The 2025 WECC system wide $CO_2$ production factor is 0.264 $lbCO_2/kWh$, 48 percent lower than the base case value. Cumulative $CO_2$ production for the WECC area for the period 2005 - 25 is reduced by 31 percent from the base case forecast.

Because this case is a sensitivity analysis rather than a scenario, the results should be used with caution. If this case were cast as a scenario, other adjustments to assumptions would have to be included. For example, natural gas prices could be expected to increase more rapidly as a result of increased development of gas-fired generating capacity. Electrical loads could be expected to moderate as a result of higher prices and additional conservation would become cost-effective. Wind resources in addition to those included in these model runs might be available, though probably at higher cost than those currently represented. New nuclear resources are not included; it is possible that new-generation modular nuclear plants might produce electricity at lower cost than the marginal resources of this case.

## Price Cap

Following a year of extraordinarily high electricity prices, the FERC implemented a floating WECC wholesale trading electricity price cap in June 2001. The original cap triggered when California demand rose to within 7 percent of supply. The cap itself was set for each occurrence based on the estimated production cost of the most-expensive California plant needed to serve

[1] As a further modeling simplification, the carbon tax was applied to all WECC areas, including British Columbia, Alberta and Baja California.

[2] Massachusetts Institute of Technology. Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal. June 2003.

load. This mitigation system was revised in July 2002 to a fixed cap of $250 per megawatt-hour, effective October 2002.

The base and sensitivity cases assume continuation of the $250/MWh wholesale price cap (year 2000 dollars, escalating with inflation). This cap undercuts several of the higher cost load curtailment and demand response blocks, curtailing peak period prices and reducing generation developed to meet peak period loads.

**Table C-3: Base and sensitivity case results**

| Case | Changes from Base | Mid-Columbia Price Forecast ($/MWh) | Ave of top 10% of Monthly Prices ($/MWh) | 2025 WECC coal (GW) | 2025 WECC gas (GW) | 2025 WECC wind & solar (GW) | 2005-25 WECC $CO_2$ Production ($MMTCO_2$) | 2025 WECC August Reserve Margin (%) | 2025 PNW January L/R Balance (aMW)[3] |
|---|---|---|---|---|---|---|---|---|---|
| ***Base Case (Changes 2005 - 2025 shown in percent)*** | | | | | | | | | |
| Final Base | -- | $36.20 | $46.18 | 64.6 (75%) | 89.7 (18%) | 29.9 (570%) | 10321 (154%) | 11% | -14 |
| ***Sensitivity Cases (Changes from base shown in percent)*** | | | | | | | | | |
| Medium-low demand forecast | NPCC Medium-low demand forecast case | $34.30 (-5 %) | $45.03 (-3%) | 53.4 (-17 %) | 82.0 (-9 %) | 31.7 (+6 %) | 9084 (-12 %) | 18 % | 3263 |
| Medium-high demand forecast | NPCC Medium-high demand forecast case | $37.70 (+4 %) | $49.92 (+8 %) | 74.6 (+16 %) | 98.7 (+10 %) | 40.0 (+10 %) | 11,562 (+12 %) | 6 % | -2808 |
| Low fuel price forecast | NPCC Low fuel price forecast case | $29.80 (-18 %) | $39.47 (-15 %) | 37.5 (-42 %) | 114.2 (+27 %) | 22.4 (-25 %) | 9187 (-11 percent) | 10 % | -471 |
| High fuel price forecast | NPCC High fuel price forecast case | $39.60 (+9 %) | $57.12 (+24 %) | 88.6 (+37 %) | 66.1 (-26 %) | 33.6 (+4 %) | 11,074 (+7 %) | 11 % | 2356 |
| Non-aggressive $CO_2$ control | $0.87/T $CO_2$ mitigation, WA & OR only | $33.90 (-6 %) | $46.64 (+1 %) | 84.2 (+30 %) | 70.2 (-22 %) | 22.2 (-26 %) | 11,028 (+7 %) | 11 % | 477 |
| Aggressive $CO_2$ control | Immediate $0.87/T $CO_2$ offset in WA & OR Climate Stewardship Act enacted 2006, Ph I in 2012 | $50.10 (+38 %) | $49.46 (+7 %) | 34.5 (-47 %) | 129.5 (+44 %) | 44.8 (+50 %) | 7126 (-31 percent) | 15 % | 2946 |

[3] Excluding demand response capability.

# Appendix C1

## MEMBERS OF THE GENERATING RESOURCES ADVISORY COMMITTEE

| Name | Affiliation |
|---|---|
| Rob Anderson | Bonneville Power Administration |
| Peter Blood | Calpine Corporation |
| John Fazio | Northwest Power Planning Council |
| Stephen Fisher | Mirant Americas Energy Marketing |
| Mike Hoffman | Bonneville Power Administration |
| Clint Kalich | Avista Utilities |
| Eric King | Bonneville Power Administration |
| Jeff King | Northwest Power Planning Council |
| Mark Lindberg | Montana Economic Opportunity Office |
| Bob Looper | Summit Energy, LLC, representing State of Idaho |
| Jim Maloney | Eugene Water & Electric Board |
| Dave McClain | D.W. McClain & Associates representing Renewable Northwest Project |
| Alan Meyer | Weyerhaeuser Corp. |
| Mike Mikolaitis | Portland General Electric |
| Bob Neilson | Idaho National Environmental and Engineering Laboratory |
| Roby Roberts | PacifiCorp Power Marketing |
| Jim Sanders | Clark Public Utilities |
| David Stewart-Smith | Oregon Office of Energy |
| Tony Usibelli | Washington Office of Trade and Economic Development |
| Carl van Hoff | Energy Northwest |
| David Vidaver | California Energy Commission |
| Kevin Watkins | Pacific Northwest Generating Coop |
| Chris Taylor | Zilkha Renewable Energy |

# Conservation Acquisition Strategies

In chapter 7, the Council proposes to engage the region on the development of a strategic plan for conservation deployment. This appendix reviews the conservation potential in the region and proposes actions needed to reach near-term conservation acquisition targets presented in chapter 7. This appendix sets forth specific acquisition approaches for the target conservation measures in the residential, commercial, irrigation and industrial sectors that the region should consider in the development of a strategic conservation plan.

## HOW MUCH CONSERVATION REMAINS TO BE DEVELOPED?

Table D-1 shows the amount of cost-effective and realistically achievable conservation savings potential by sector and end-use under the Council's medium wholesale electric price forecast. As can be see in Table D-1, the Council has identified about 2,800 average megawatts of conservation resources that could be developed during the next 20 years under these conditions.[1] This is enough energy to replace the output of about 18 single-unit combined cycle combustion turbine power plants, at about half the cost.[2] Almost 20 percent of this potential is in new and existing residential lighting. The next largest single source of potential savings, about 12 percent of the total, is in the non-aluminum industrial sector. The remaining large sources of potential savings are spread across residential water heating and laundry equipment and new and existing lighting and HVAC equipment in the commercial buildings.

[1] This is the total amount of cost-effective conservation achievable, given sufficient economic and political resources, over a 20-year period in the medium forecast.
[2] Based on a 305 megawatts single-unit combined-cycle gas-fired plant (270 megawatts baseload + 35 megawatts duct-firing) seeing service in 2005. For the 2005-2019 periods, under average conditions, such a plant would operate at an average capacity of 156 megawatts with a levelized cost of $45.20/megawatt-hour (2000$).

**Table D-1: Achievable Conservation Potential**

| Sector and End-Use | Cost-Effective Savings Potential (MWa in 2025)[3] | Average Levelized Cost (Cents/kWh)[4] | Benefit/Cost Ratio[5] | Share of Savings (Percent) |
|---|---|---|---|---|
| Residential Compact Fluorescent Lights | 530 | 1.7 | 2.3 | 19 |
| Residential Heat Pump Water Heaters | 200 | 4.3 | 1.1 | 7 |
| Residential Clothes Washers | 140 | 5.2 | 2.6 | 5 |
| Residential Existing Space Conditioning - Shell | 95 | 2.6 | 1.9 | 3 |
| Residential Water Heaters | 80 | 2.2 | 2.3 | 3 |
| Residential HVAC System Conversions | 70 | 4.3 | 2.1 | 3 |
| Residential HVAC System Efficiency Upgrades | 65 | 2.9 | 1.2 | 2 |
| Residential New Space Conditioning - Shell | 40 | 2.5 | 2 | 1 |
| Residential Hot Water Heat Recovery | 20 | 4.4 | 1.1 | 1 |
| Residential HVAC System Commissioning | 10 | 3.1 | 1.9 | 0.4 |
| Residential Existing Space Conditioning - Duct Sealing | 10 | 3.1 | 1.9 | 0.4 |
| Residential Dishwashers | 10 | 1.6 | 2.6 | 0.4 |
| Residential Refrigerators | 5 | 2.1 | 2.2 | 0.2 |
| Commercial New & Replacement Lighting | 221 | 1.3 | 8.6 | 8 |
| Commercial New & Replacement HVAC | 140 | 3.0 | 1.5 | 5 |
| Commercial Retrofit HVAC | 119 | 2.4 | 1.9 | 4 |
| Commercial Retrofit Lighting | 117 | 3.4 | 1.3 | 4 |
| Commercial Retrofit Equipment[6] | 114 | 1.8 | 2.2 | 4 |
| Commercial Retrofit Infrastructure[7] | 105 | 2.2 | 1.8 | 4 |
| Commercial New & Replacement Equipment | 84 | 2.2 | 1.8 | 3 |
| Commercial New & Replacement Shell | 22 | 2.2 | 1.6 | 1 |
| Commercial New & Replacement Infrastructure | 11 | 1.4 | 2.4 | 0.4 |
| Commercial Retrofit Shell | 4 | 3.8 | 1.0 | 0.1 |
| Industrial Non-Aluminum | 350 | 1.7 | 2 | 13 |
| Agriculture - Irrigation | 80 | 1.6 | 3.2 | 3 |
| New & Replacement AC/DC Power Converters[8] | 155 | 1.5 | 2.7 | 6 |
| Total | **2797** | **2.4** | **2.5** | **100** |

Table D-1 also shows average real-levelized cost and the benefit-to-cost ratio of the region's remaining conservation potential by major end-use. The weighted average real-levelized cost of this

[3] This is the total amount of conservation estimated to be cost-effective and achievable, given sufficient economic and political resources, over a 20-year period under the medium forecast of loads, fuel prices, water conditions, and resource development.
[4] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.
[5] These "benefit-to-cost" (B/C) ratios are derived by dividing the present value benefits of each measure's energy, capacity, transmission and distribution and non-energy cost savings by the incremental present value cost (including program administration) of installing the measure.
[6] Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls and laboratory fume hoods.
[7] Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.
[8] Measure occurs in residential, commercial and industrial sectors.

conservation is 2.4 cents per kilowatt-hour (2000$).[9] In aggregate, these resources have a benefit-to-cost ratio of 2.5-to-1.0.[10] Note that some measures, such residential clothes washers, can have high-levelized cost while still providing high benefit-to-cost ratios. This seemingly counter-intuitive result can occur for several reasons. It may be that a measure, such as a high-efficiency air conditioner or heat pump, produces most of its savings at times when wholesale power market prices are high and therefore are more valuable to the region. Alternatively, this phenomenon can occur when a measure produces very large non-energy benefits such as the water savings from more energy-efficient residential clothes washers.

The amount of conservation that is cost-effective to develop depends upon, among other things, how fast the demand for electricity grows, future alternative resource costs and year-to-year variations in market prices.[11] It also depends upon whether the extent to which conservation in the region's resource portfolio can reduce the risk associated with future volatility in wholesale market prices, changes in technology, potential carbon controls and other risks. In order to assess whether 2,800 average megawatts (or some other amount) of conservation resource is more likely to provide the Northwest consumers with the lowest cost power system at an acceptable level of risk the Council tested a range of conservation deployment strategies in its portfolio analysis process and discussed in chapter 7.

## REGIONAL CONSERVATION TARGET

Based on the portfolio analysis in chapter 7, the Council recommends that the regional target 700 average megawatts of conservation development over the next five years. This includes 600 average megawatts of cost-effective discretionary conservation and 100 average megawatts of lost-opportunity conservation. The Council believes that acquisition of these targets will produce a more affordable and reliable power system than alternative development strategies. The Council recognizes that the 700 average megawatts five-year conservation target it is recommending represents a significant increase over recent levels of development. However, the Council's analysis of the potential regional costs and risks associated developing lesser amounts of conservation demonstrates that failure to achieve this target exposes the region to substantially higher costs and risks.

Figure D-1 shows the Council's recommended targets by sector and resource type for the five-year action plan. These near-term targets call for constant levels of development of discretionary conservation and a steady acceleration of lost-opportunity conservation.

Figure D-2 shows the long-range mean build-out of lost-opportunity and discretionary conservation from the least risk plan. It is important to note that the Council recommends that acquisition rates of lost-opportunity resources continue to increase beyond the 30 average megawatts per year in 2009 shown in Figure D-1. The Council recommends that by no later than 2017, lost-opportunity resource acquisition should reach an 85 percent penetration rate. Under the medium forecast this would be about 70 average megawatts per year.

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

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

[11] For example, if economic growth follows the Council's medium-low forecast, the region will need to add approximately 100 average megawatts of new resources each year. However, if regional economic growth is at the Council's medium-high forecast, nearly 400 average megawatts of new resources will be needed each year.

The Council expects that total utility system investments in conservation needed to achieve its five-year target will be approximately in the range of $1.2 to $1.35 billion, or $200 to $260 million (2000$) per year.[12] This is slightly less than the $1.45 billion (2000$) in utility investments from 1992 through 1996 when the region captured similar amounts of conservation. It is about one-third more than average utility and Bonneville expenditures over the ten years from 1991 to 2002. The Council understands the difficulty of raising power rates to accomplish this level of investment. This means that acquiring conservation as cost-efficiently as possible must be a high priority.

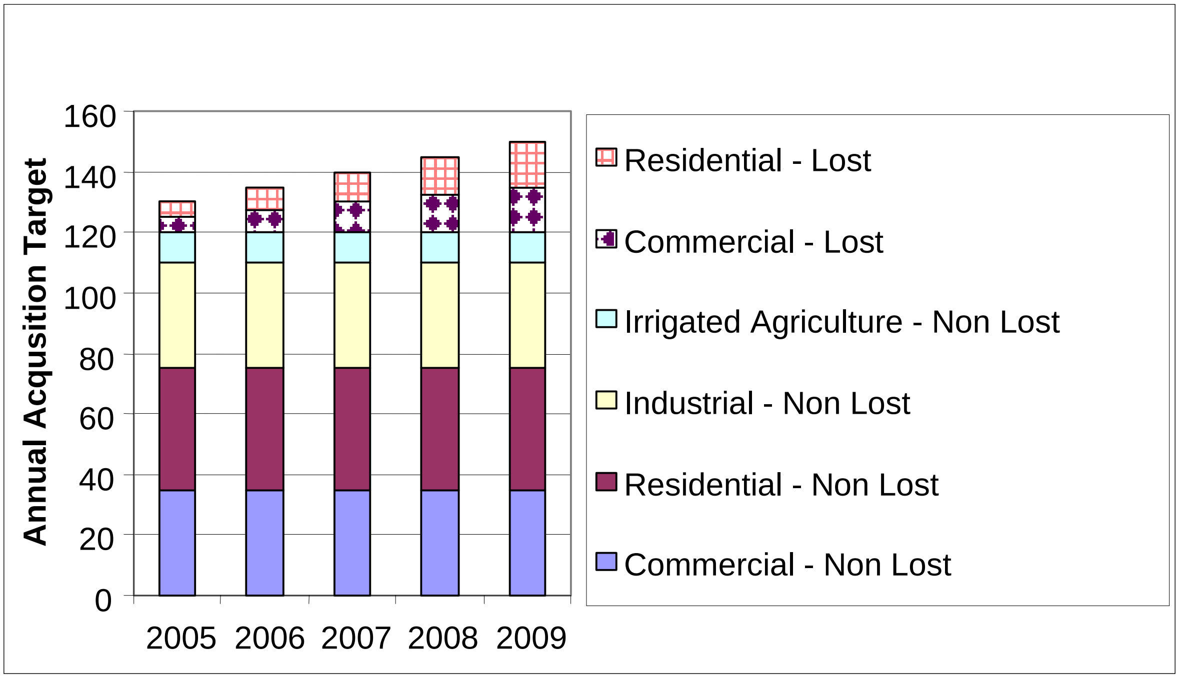


**Figure D-1: Regional Conservation Targets 2005 - 2009**

[12] The range of utility program costs estimated here is based on two methodologies. The high range of the estimate is based on $2.2 million per average megawatt saved, the 1991-2002 utility program cost average. This method yields a five-year average annual estimate of about $300 million, of which as much as $40 million could be for market transformation and regional acquisition activities. This method results in a high estimate of about $260 million per year over five years for local utility program expenditures. This is thought to be the high end of the range. Utility program costs per average megawatt have been lower since 1995, about $1.5 million per average megawatt. But historical performance may not be a good indicator of future costs. The future measures are different and there are new lost-opportunity programs to be developed. The low range of the utility program cost estimate is based on utility costs being a fraction of the total resource cost of the lost-opportunity measures in Council's conservation assessment. This method takes into account that there are different measures and programs going forward. For the second methodology the Council assumed utility costs are expected to be at or above 100 percent of the total resource cost of the lost-opportunity measures due to expected high initial start up costs for new programs. For discretionary measures, the Council assumed about 65 percent of the total resource cost of the measures would be needed in utility incentives and program costs. This second method yields a five-year annual average utility cost estimate of about $240 million. Again assume as mush as $40 million per year could be for market transformation and regional acquisition activities. That yields a low-end estimate of about $200 million per year for local utility program costs not including market transformation and regional acquisition activities. In 2002 Bonneville, the utilities and the SBC administrators spent about $200 million on local programs not including the Alliance.

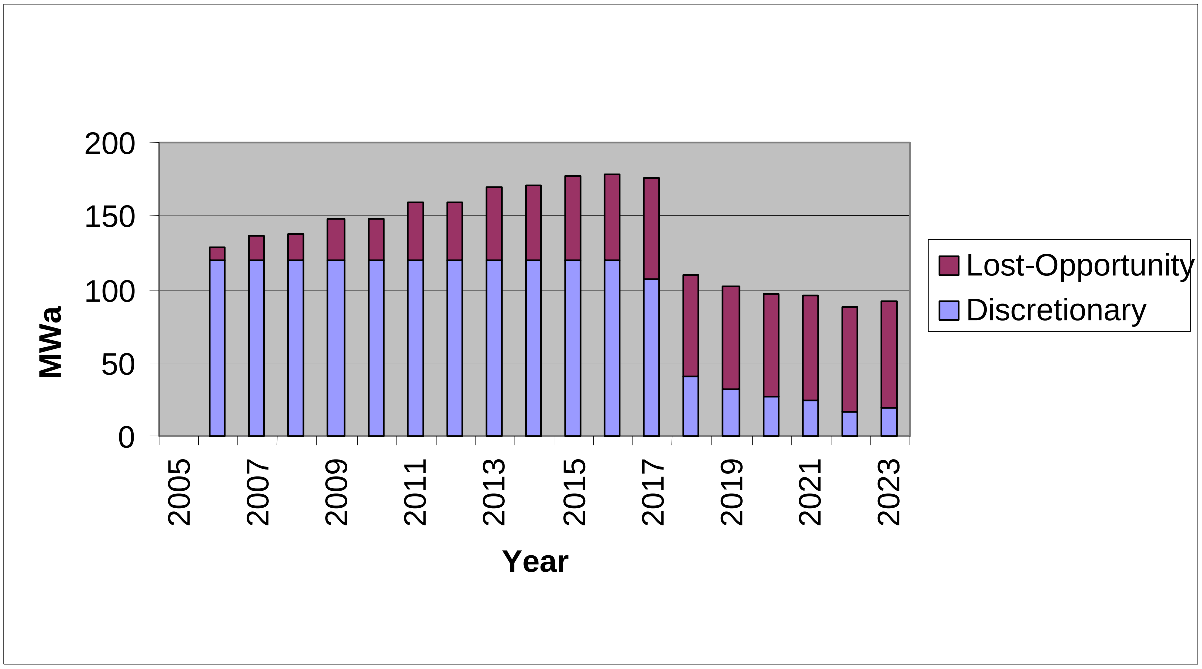


**Figure D-2: Mean Annual Build-Out of Conservation in Plan**

## CONSERVATION IMPLEMENTATION STRATEGIES

Acquiring cost-effective conservation in a timely and cost-efficient manner requires thoughtful development of mechanisms and coordination among many local, regional and national players. This power plan cannot identify every action required to meet the conservation targets. However, the specific characteristics of the targeted conservation measures and practices, market dynamics, past experience and other factors suggest acquisition approaches that promise to be fruitful and effective. This section outlines major acquisition approaches and levels of effort that the Council recommends be pursued by entities in the region to secure the benefits from capturing the region's cost-effective conservation potential. It also sets forth some guidance on specific issues that the Council believes must be addressed in order to achieve its cumulative 2005 through 2009 target of 700 average megawatts.

### Focus on "Lost Opportunity" Resources

The Council's portfolio analysis found that developing additional conservation serves as a "hedge" against future market price volatility. One of the principle factors behind the finding is that more "lost opportunity" resources are developed.[13] As described in the discussion of the results of the portfolio analysis, capturing these lost opportunity conservation resources reduces both net present value system cost and risk. If the region does not develop these resources when they are available, this value cannot be secured. These resources represent nearly half of the Council's 20-year

13 A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use. For example, some efficiency measures can only be implemented cost-effectively when a building is being constructed or undergoing major renovation. If they aren't done then, the opportunity to capture those savings at that cost is lost.

conservation potential if they could be developed for 85 percent of new buildings, appliances and equipment. But programs need to be initiated for many of the new lost-opportunity resources identified in this plan and the Council expects it may take as long as twelve years to reach an 85 percent penetration rates. Therefore, the region needs to focus on accelerating the acquisition of these resources. This will very likely require significant new initiatives, including local acquisition programs, market transformation ventures, improving existing and adopting new codes and standards, and regional coordination.

## Additional Regional Coordination and Program Administration will be Required

The Council believes coordinated efforts will be an increasingly necessary ingredient to successful development of the remaining conservation potential. The boundaries between direct acquisition approaches, market transformation, infrastructure support, and codes and standards are blurry. In fact, for much of the conservation resource, efforts are needed on all these fronts to take emerging efficiency measures from idea to common practice or to minimum standard. Of increasing importance is improved coordination between local utilities, public benefits charge administrators, the Alliance, Bonneville, the states and others to assure efforts are targeted where they have the most impact on resource development and where synergies of approach and combined efforts can be taken advantage of.

In addition, a significant share of the savings identified by the Council require a regional scope to achieve economy of scale or market impacts or can be best acquired through regionally-administered programs. However, at present there is no regional organization chartered or funded to develop and administer such programs. In the past Bonneville has played this role.[14] However, it is not clear that Bonneville could or should continue to provide this function in the future. The Council intends to use the strategic planning process identified in its action plan to work with the Alliance, Bonneville, the region's utilities and system benefits charge administrators and regulators develop a solution to this problem.

## Aggressive Action by the Power System is Necessary

As in most previous Council power plans, this plan does not attempt to quantify the portion of the achievable conservation that might be developed by consumers acting independent of utility or system benefits administrator programs. There are several reasons for this. First, to the extent feasible the Council has attempted to account for existing market penetration of consumer investments in energy efficiency and the effects of know future codes and standards. These have already been subtracted from estimates of future potential.

Second, the Council is charged with determining which mix of resources will provide the region with most economically efficient and reliable electric power system and services. Allocating the targets and the cost of meeting them between the region's consumers and its electric ratepayers does not change the total cost to the region of acquiring these savings. More importantly, since these two groups are comprised of the same individuals, from a regional perspective it makes no difference who pays -- the total bill is the same.

14 For example, Bonneville administer the Manufactured Housing Acquisition Program (MAP) on behalf of all of the region's public and investor-owned utilities.

Third, this Plan's conservation target is achievable, yet aggressive. In order to achieve these targets, the region will need to make significant investments in conservation resources. While these conservation resources are less expensive than other resource options, their costs are front-loaded. This is especially true for "lost-opportunity" conservation resources because these resources have measure lives that typically exceed the 20-year planning period.[15] Only about 300 average megawatts of the 3,900 achievable average megawatts identified have real-levelized cost below 1.0 cent per kilowatt-hour. Even these conservation resources have "payback" periods exceeding those typically demanded by commercial and industrial customers. Given these facts, the Council is convinced that this Plan's conservation targets cannot be achieved without broad-based and aggressive programs. While these programs should be designed to target measures that would not otherwise be adopted and focus on consumers that would not likely adopt energy efficient technologies, those considerations should not drive program design.

## Efficient Programs Are Not Necessarily Those With the Lowest (First Year) Cost

As noted in the previous discussion, conservation resource costs are "front-loaded." Therefore, measuring effectiveness of local or regional conservation acquisition programs based on their cost per first year savings is, at the very least, misleading and at worst, misguided. Lost-opportunity resources comprise fifty percent of the Council's assessment of 20-year conservation potential. These resources, as noted above, are by definition "long-lived." Moreover, because the region has been successful in improving energy codes, federal efficiency standards and building practices a significant share of the remaining lost-opportunity potential is more costly than "average." These two factors create a conflict between getting conservation "cheap" and achieving the Council's lost-opportunity targets.

To illustrate this conflict consider the following example. High-efficiency clothes washers represent 135 average megawatts of resource potential. Their real levelized cost is 5.2 cents per kilowatt-hour and they have a benefit-to-cost ratio of 2.6. The "first year cost" of savings from high efficiency clothes washers is $4.8 million per average megawatt. Compact fluorescent lamps (CFLs) represent 530 average megawatts of non-lost opportunity resource potential. They have a real levelized cost of just over 1.7 cents per kilowatt-hour and a benefit-to-cost ratio of 2.3. The "first year cost" of CFL savings is $1.4 million per average megawatt. If a conservation program operator "capped" its "willingness to pay" at $1.0 million per average megawatt it might forego securing one or both of these resources. Alternatively, to limit its costs, it might offer incentives to consumers that are so small that only those consumers who would have purchased the efficient clothes washer or CFLs end up participating in its program. As a result, the program produces no "incremental savings" beyond what the market would have done on its own.

This is not to say that the conservation should not be acquired at as low a cost to the power system as possible. While everyone benefits from cost-effective conservation, the end-user participants benefit most directly. Given that retail rates have risen significantly in recent years, end users have a greater incentive to share in the cost of the conservation. But the Council's goal is to achieve the 700 average megawatts 2005 through 2009. Whether the region's consumer's pay for more or less of the cost of doing so through their electric rates, while important, is a secondary goal.

[15] The "first year cost" of a measure with a real-levelized cost of just 1.0 cents per kilowatt-hour and a 20 year lifetime is over 17 cents per kilowatt-hour. At a retail electric rate of 5.0 cents per kilowatt-hour this measure would have a simple payback of over 3.5 years.

## A Mix of Mechanisms Will Need to Be Employed

There are several acquisition approaches that have been used successfully in the region and around the country to develop cost-effective conservation not captured through market forces. Key among these are: direct acquisition programs run by local electric utilities, public benefit charge administrators, Bonneville or regional entities; market transformation ventures; infrastructure development; state building codes; national and state appliance and equipment standards; and state and federal tax credits. The Council believes a suite of mechanisms should continue to be the foundation used to tap the conservation resource.

It is the nature of the conservation resource, the kinds of measures and practices, and the inherent advantages of different acquisition approaches that suggest how much of the conservation potential should be pursued, by what entities and using which methods. Most of the successful conservation development over the past two decades has been through a combination of approaches deployed over time. Typically pilot projects demonstrate a new technology. Direct acquisition programs are used initially to influence leading decision makers to adopt the technology. Market transformation ventures are used to bring the technology to be part of standard practice. Then, in some cases, codes or standards can be upgraded to require the new measures, or capture a portion of the cost-effective savings.

### Direct Acquisition Programs

Direct acquisition programs are typically programs run by local utilities, system benefits charge administrators, regional organizations, Bonneville and others that offer some kind of incentive to get decision makers to make energy-efficient choices. Incentives often take the form of rebates, loans, or purchased energy savings agreements. Direct acquisition programs are relatively expensive compared to other approaches because the incentive can be a significant fraction of the measure cost and substantial administrative costs are required. Historic program costs range from 1 to 5 million dollars per first-year average megawatt of savings. However, in many cases, direct acquisition programs are the only mechanism available or are a necessary first step to get new measures and practices into the market place. Acquisition programs can be local or regional. Many retrofit programs for residential and commercial building are best run as local efforts. On the other hand, for measures where there are just a few suppliers or vendors in the region, a regional approach to direct acquisition may be more cost-efficient.

### Market Transformation Ventures

Market transformation ventures are regional and national efforts to get energy-efficient products and services adopted by the marketplace sooner and more thoroughly than they would be otherwise. The Northwest Energy Efficiency Alliance (Alliance) is the key entity in the region pursuing this approach. The Alliance has developed an impressive track record of improving the adoption of efficiency measures and practices in most of the markets it has ventured into racking up sizeable low-cost energy savings of about 100 average megawatts at a cost of $1 million per first-year average megawatt or less.[16] The Council envisions continued market transformation efforts will yield similarly impressive results at similarly low costs.

[16] Retrospective Assessment Of The Northwest Energy Efficiency Alliance, Final Report, by Daniel M. Violette, Michael Ozog, and Kevin Cooney, Available at http://www.nwalliance.org/resources/reports/120.pdf

### Conservation Infrastructure Development

Often, the delivery of new energy-efficient products and services requires development of, or intervention in, the infrastructure that proposes to deliver those products or services. Conservation infrastructure includes education, training, development of common specifications for efficient practices or equipment, certification programs, market research, program evaluation and other activities that support quick, widespread adoption of energy efficiency that delivers savings. Infrastructure development is often best approached at a regional or national level if the product or service is one that crosses the boundaries of local utilities. The Alliance, Bonneville, the states, the federal government and some national organizations have fostered infrastructure development in the past. For example, the federal government's Energy-Star program identifies products that meet minimum efficiency levels for common household appliances. Both market transformation ventures and direct acquisition programs can use the federal designation to promote products in regional and local markets.

In the past, some infrastructure development has been supported through the Alliance. But limited Alliance budgets, combined with increasing need for regional infrastructure has orphaned some efforts. The Council believes more effort should be directed to regional infrastructure in the next five years to speed the development and lower the cost of capturing all cost-effective savings.

### Building Codes

Residential and commercial energy codes are adopted at the state and local level to require minimum levels of efficiency in many of the energy-using aspects of new homes and commercial buildings. Energy codes are typically part of the building code and typically lag behind leading-edge efficiency practices. Once adopted as the minimum standard, codes generally lead to decreasing measure costs. However, not all cost-effective conservation can be captured by buildings codes. Code improvement is a continual process and regional efforts need to continue.

### Appliances and Equipment Standards

The federal government, and some state governments adopt minimum efficiency standards for certain appliances and equipment. Federal laws dictate that certain appliances fall under federal jurisdiction and timelines for minimum efficiency standards. Other appliances and equipment are not under federal jurisdiction but might be subject to state or local standards. The region should continue to place significant efforts on improving federal appliance standards and to adopt new state standards for some appliances.

### Tax Credits

State and national tax credits have been used effectively to promote efficient equipment and practices beyond what is required in federal standards and state codes. State laws differ and may limit the ability of a state to offer tax credits. However, in instances like Oregon's Business Energy Tax Credit, these mechanisms have been effective.

## RECOMMENDED ACQUISITION STRATEGIES AND MECHANISMS

The Council considered the mechanisms above, the kinds of measures and practices that comprise the conservation assessment, and the state of development of each in order to get a general idea of what level of effort to apply to each of these approaches to capture the conservation potential identified in this plan.  Suggested approaches are based on the characteristics of the potential conservation including whether it is lost-opportunity or retrofit, it's size, cost, and non-energy benefits, characteristics of the market and delivery channels used disseminate the measures, local, state, regional and national programs already in place, and if and when a measure or practice might be subject to codes or standards.

The following sections set forth near-term acquisition approaches, strategies and suggested mechanisms by sector for the key measures that make up the conservation targets.  These are presented as starting points for a regional dialogue of how best to capture the targeted conservation. The specific mechanism or mix of mechanisms best suited to capture this resource will need to be addressed during the development of the region's strategic plan for conservation acquisition.

## Residential-Sector Conservation Acquisition Strategies

Table D-2 shows the achievable savings, real levelized cost, benefit-to-cost ratio, total resource capital cost per average kilowatt and the share of sector savings for each of the major sources of residential sector potential.  As can be seen from this table, the residential sector conservation potential is highly concentrated among just three measures.  Nearly 70 percent of the realistically achievable residential sector conservation potential comes from three measures, compact florescent lighting, heat pump water heaters and high efficiency clothes washers.  Moreover, of the remaining 30 percent, 10 percent comes from improving the efficiency of heat pumps and converting existing electric furnaces to high efficiency heat pumps and 6 percent comes from high efficiency water heater tanks.  The remaining 14 percent of the sector's potential savings is spread among 12 other major measure types.

**Table D-2: Sources and Total Resource Cost Economics of Residential Sector Realistically Achievable Conservation Potential**

| Measure | Realistically Achievable Potential (MWa) | Weighted Levelized Cost (Cents/kWh) | Benefit/ Cost Ratio | Weighted[17] Total Resource Capital Cost ($/KWa) | Share of Sector Realistically Achievable Potential |
|---|---|---|---|---|---|
| Energy Star Heat Pump Conversions | 70 | 4.3 | 2.1 | $ 4,520 | 5% |
| Energy Star Heat Pump Upgrades | 60 | 2.9 | 2.1 | $ 3,170 | 5% |
| PTCS Duct Sealing | 10 | 3.1 | 2.3 | $ 3,640 | 1% |
| PTCS Duct Sealing and System Commissioning | 5 | 3.0 | 2.2 | $ 3,520 | 0% |
| PTCS Duct Sealing, Commissioning and Controls | 10 | 3.2 | 2.3 | $ 3,860 | 1% |
| Energy Star - Manufactured Homes | 20 | 2.3 | 2.1 | $ 4,240 | 2% |
| Energy Star - Multifamily Homes | 5 | 2.3 | 1.1 | $ 4,620 | 0% |
| Energy Star - Single Family Homes | 20 | 2.7 | 1.1 | $ 5,490 | 2% |
| Weatherization - Manufactured Home | 20 | 4.0 | 1.1 | $ 5,490 | 2% |
| Weatherization - Multifamily | 30 | 2.5 | 1.1 | $ 4,480 | 2% |
| Weatherization - Single Family | 40 | 1.9 | 2.4 | $ 3,500 | 3% |
| Energy Star Lighting | 530 | 1.7 | 2.3 | $ 1,370 | 42% |
| Energy Star Refrigerators | 5 | 2.0 | 2.3 | $ 2,330 | 0% |
| CEE Tier 2 Clothes Washers | 140 | 5.2 | 1.1 | $ 4,820 | 11% |
| Energy Star Dishwashers | 10 | 1.6 | 2.6 | $ 1,480 | 1% |
| Efficient Water Heater Tanks | 80 | 2.2 | 2.3 | $ 1,810 | 6% |
| Heat Pump Water Heaters | 200 | 4.3 | 1.1 | $ 4,240 | 16% |
| Hot Water Heat Recovery | 20 | 4.4 | 1.1 | $ 7,620 | 2% |
| **Total** | **1,275** | **2.9** | **1.9** | **$ 2,960** | **100%** |

Table D-3 shows approximate residential sector conservation target for 2005 through 2009 is 250 average megawatts. During the initial five years of this plan only twenty percent of this target is comprised of lost-opportunity resources to allow for the gradual ramp up of programs. Increasing the market penetration of high efficiency clothes washers and water heater efficiency improvements represent the principle areas where programs need to be focused. A single measure, Energy Star Lighting (compact fluorescent lamps) represents two-thirds of total five-year target for the residential sector. The fact that the bulk of the residential sector savings potential is concentrated in just a few measures reduces the number of mechanisms that may be required to capture this potential at any particular point in time. However, The Council believes that over the course of the next 20 years, nearly the full array of mechanisms and approaches will still be required to accomplish this sector's savings.

17 This is the entire incremental capital cost of the measure plus program administrative cost. Since utilities and system benefit charge administrators rarely pay 100 percent of a measure's cost, their cost will be below this value.

**Table D-3: Residential Sector Lost Opportunity and Dispatchable Conservation Resource Targets 2005 through 2009**

| Measure | Five Year Dispatchable Target (Average Megawatts) | Five Year Lost Opportunity Target (Average Megawatts) |
|---|---|---|
| Energy Star Heat Pump Conversions | - | 5.6 |
| Energy Star Heat Pump Upgrades | - | 4.8 |
| PTCS Duct Sealing | 3.1 | - |
| PTCS Duct Sealing and System Commissioning | 1.6 | - |
| PTCS Duct Sealing, Commissioning and Controls | 3.1 | - |
| Energy Star - Manufactured Homes | - | 1.8 |
| Energy Star - Multifamily Homes | - | 0.1 |
| Energy Star - Single Family Homes | - | 1.2 |
| Weatherization - Manufactured Home | 6.2 | - |
| Weatherization - Multifamily | 9.3 | - |
| Weatherization - Single Family | 12.4 | - |
| Energy Star Lighting | 164.3 | - |
| Energy Star Refrigerators | - | 0.4 |
| CEE Tier 2 Clothes Washers | - | 11.2 |
| Energy Star Dishwashers | - | 0.8 |
| Efficient Water Heater Tanks | - | 6.4 |
| Heat Pump Water Heaters | - | 16.0 |
| Hot Water Heat Recovery | - | 1.6 |
| **Total** | **200** | **50** |

## Residential-Sector Lost Opportunity Resources

While most of the lost-opportunity resources are probably best targeted by regional or national market transformation ventures, several can benefit from complimentary local acquisition program in the near-to intermediate term. For example, the two largest lost-opportunity resources are high efficiency clothes washers and heat pump water heaters.

### *Residential Clothes Washers*

The minimum permissible efficiency of clothes washers is set by federally preemptive appliance standards. These standards were last updated in 2001. The first "phase" of the 2001 standards took effect in January of 2004 and the second "phase" of those standards will take effect in January of 2007. By law, the US Department of Energy cannot revise the standard more than once every five years. This means that the first year a new clothes washer standard could take effect is 2012. Therefore, between now and then, a regional market transformation venture complimented by local acquisition programs and state tax credits that focus on the most efficient washers is needed to capture this resource. In addition, the region should continue to actively participate in the federal appliance standards rulemaking process to ensure that the higher efficiency standards are adopted in a timely manner.

### *Residential Heat-Pump Water Heaters*

In contrast, securing the lost opportunity savings available from heat pump water heaters will require a quite different mix of mechanisms. The principle barriers to widespread application of this technology are that prior generations of heat pump water heaters were unreliable, too expensive or both and they lacked a national distribution network. As a result of federal research and demonstration efforts, the current generation of heat pump water heaters are now much more reliable. However, they still have an incremental cost (over a standard electric water heater) of about $800-900 and are not available through existing plumbing supply distribution networks. In order to overcome these barriers, a regional scale demonstration program coupled with either a regional or national market transformation venture are required.

The regional demonstration program is needed to convince contractors and consumers that this technology is as reliable as a standard electric water heater. This program needs to be of sufficient scale and duration to create a national (or regional) market for heat pump water heaters that is large enough to gain both economies of scale for manufacturers as well as to develop the regional distribution network. The Council believes that the Northwest Energy Efficiency Alliance (Alliance), working with both its regional partners and other national and regional organizations,[18] is the logical entity to lead the development of this resource.

During the initial stages of this venture it is highly probable that either significant local acquisition program incentives or manufacturer incentives will be required to defray a portion of the incremental cost of heat pump water heaters. The Council does not believe that the Alliance could realistically mount a successful market transformation venture for heat pump water heaters within its current budget constrains. For example, if the Alliance were to negotiate an agreement with manufacturers to cover 50 percent of the incremental capital cost of acquiring the savings from heat pump water heaters the annual cost of a successful program could be in the range of $10 to $15 million. This represents 50 to 75 percent of the Alliance's current annual budget for all of its activities. While these "acquisition payments" could be provided by local utilities, the Council believes that providing the Alliance with the ability to negotiate a single region wide payment to heat pump water heater manufacturers for all units installed in the region (as was done in the Manufactured Housing Acquisition Program) represents a more efficient mechanism for acquiring these savings. The specific mechanism or mix of mechanisms best suited to capture this resource will need to be addressed during the development of the region's strategic plan for conservation acquisition

### *Residential Water Heaters and Residential Heat Pump Space Heaters*

The next two largest lost opportunity resources are high efficiency hot water tanks and the installation of high efficiency heat pumps in both new homes and the conversion of existing homes with other forms of electric heat to high efficiency heat pumps when the existing heating system is replaced. As is the case with clothes washers, the federal standards for both of these standards were recently revised. New standards for electric hot water heaters took effect in January of 2001 and new standards for air source heat pumps for space heating and cooling will go into effect in January of 2006. Local acquisition programs have successfully targeted high efficiency water heaters. The Council recommends that these programs be enhanced and expanded to ensure that a greater

[18] Ideally, a national market transformation venture should be implemented involving the Consortium for Energy Efficiency, the New England Energy Efficiency Partnerships, the Mid-West Energy Efficiency Alliance and other organizations so as to maximize the scale of the market demand for this product.

proportion of electric water heater tanks installed in both new and existing homes are high efficiency tanks.[19]

Capturing the savings from the installation of more efficient air source heat pumps involves more than selecting a higher efficiency unit. The Council's savings estimate also assumes that the heat pump and the ductwork through which it distributes warm or cool air have been installed properly. In fact, the bulk of the savings from this measure are actually derived from better installation practices and sealing the "leaks" in ductwork. Local acquisition programs designed to capture this resource must therefore focus on improving the installation practices of contractors and their technicians. This will require support of training and quality control/quality assurance programs in addition to direct program incentives.

***Residential New HVAC systems***

In new construction, the Alliance, working with its regional partners, recently embarked on an Energy Star new homes program that requires the proper installation of more efficient heat pumps and verification that the ductwork is indeed "tight." Local utility and system benefit charge administrator acquisition programs should compliment this venture. Local programs should also target heat pump installations in non-Energy Star new homes as well as be designed secure savings from the proper installation of high efficiency heat pumps and "duct sealing" in existing homes that are replacing their heating systems. The savings from "duct sealing" in both new and existing homes could be secured at a later date. However, failure to seal the duct system when the heat pump is installed dramatically reduces the heat pump's efficiency and also increases the cost of this measure since the home would have to be revisited.

***Residential Appliances***

The remaining lost opportunity conservation potential can be achieved by increasing the market share of high efficiency refrigerators, freezers and dishwashers and by increasing the efficiency of new electrically heated site built and manufactured homes. Current Alliance, utility and system benefits administrator programs aimed at increasing the market share of Energy Star refrigerators, freezers and dishwashers should be continued. In addition, the region should support revisions to the federal minimum standards for these appliances.

***New Homes***

Under the Council's medium load growth forecast, approximately two average megawatts of savings are achievable each year through improvements in the thermal efficiency of new single family, multifamily and manufactured homes. As mentioned above, the Alliance recently commenced an Energy Star new site built homes market transformation venture that attempts to capture the portion of these savings. In its initial stages this venture does not focus on multifamily construction. The Council believes that since a high percentage of multifamily buildings are electrically heated, the Alliance should develop and implement a market transformation strategy that targets these dwellings. The Council also recommends that local utility and system benefit administrator programs be designed to compliment the Alliance initiatives. To the extent possible these programs

[19]The minimum "Energy Factor" (EF) for a high efficiency tank varies with tank capacity. The larger the tank the lower the minimum EF. For a tank with a rated capacity of 50 gallons the Council recommends a minimum EF of 0.93.

should encourage the installation of high efficiency appliances, lighting and building thermal shell measures as part of an overall package.

Since the early 1990's the region's manufactured home suppliers in cooperation with the state's energy agencies, Bonneville and the region's utilities have supported the sales of high efficiency manufactured homes under the Super Good Cents® brand name. The industry has voluntarily underwritten the entire cost of the independent third-party inspection and certification program operated by the region's state energy agencies for the past 10 years. Under an agreement with the US Environmental Protection Agency, these homes are now being co-branded as meeting the Energy Star® certification requirements. Super Good Cents®/Energy Star® homes now represent just under two-thirds of all new manufactured homes sited in the region.

While by any metric this program continues to be a national model for what can be achieved through market transformation, its current specifications do not require homes to include all measures that are regionally cost-effective nor has it penetrated 85 percent of the market. It must accomplish both of these tasks in order to capture the lost opportunity savings identified in Table D-3. Therefore, the Council recommends that the state agencies and region's manufacturers adopt a revised set of specifications. The Council also recommends that utilities and system benefit administrators expand their support of this program so that it can achieve a greater market share. Enhance support for the program should be guided by an analysis of the market and other barriers that must be overcome to increase the market penetration rate of Super Good Cents®/Energy Star® manufactured homes.

### *Residential Hot Water Heat Exchanger*

The remaining residential lost opportunity resource identified by the Council is a recently developed technology to recapture the waste heat contained in shower water as it drains out of the shower. This technology works by a principle called "gravity film adhesion". Warm water exiting through a vertical drain line does not "free fall" through the center of the pipe, but rather "adheres" to the side of the pipe, warming the pipe as it flows downward. The heat given off by this exiting shower water can be recaptured by wrapping copper tubing around the shower drain line and running the incoming cold water supply to the shower through the tubing. This pre-heats the cold water supply and reduces the amount of hot water needed to provide a comfortable shower.

A limited number of "gravity film heat exchange" (GFX) devices have been installed in the region. In order to work effectively these devices need to be installed where the shower drain line has at least a four-foot vertical drop. This limits their practical application to multifamily structures and two-story or basement homes. The Council has assumed that only one quarter of the new multifamily and single family residences built over the next twenty years could realistically install these devices. However, if state energy codes were to require that GFX devices be installed in all new homes and multifamily buildings (where physically feasible) then the regional savings from this measure could be four times larger or roughly 80 average megawatts.

In order to capture this potential savings from GFX devices will require a regional demonstration of the technology to familiarize builders, plumbers and code officials with its installation and operation. The Council believes that the Alliance is best positioned to identify the barriers to widespread market acceptance of this technology. Once the Alliance has completed the necessary market research it should design and implement a strategy to expand the market share GFX devices with the end goal of incorporating them into state energy or plumbing codes. In addition, the Council believes that local utility and system benefits charge administrator acquisition programs will need to target this device as part of their the Energy Star® new homes programs.

## Residential-Sector Dispatchable Resources

About half of energy savings potential identified in the residential sector can be scheduled for development nearly anytime during the next twenty years, primarily through retrofits of existing residential lighting.

### *Residential Compact Fluorescent Lighting (CFL)*

Research conducted by the Alliance indicates that the average household has about 30 "sockets" that use a standard "Edison" base. Based on estimated historical sales of CFLs in this region the Council believes that about 10 percent of these "sockets" now contain CFLs. With recent (and continuing) improvements in CFL technology, virtually all of the remaining sockets with incandescent bulbs could be retrofitted with CFLs over the next twenty years.

Although the cost of CFLs has dropped dramatically over the past five years, they still cost at least three to four times as much as standard incandescent bulbs. Specialty bulbs, such as multi-wattage/output and those with dimming capability are significantly more expensive than their incandescent equivalents. Consequently, the Council believes that current Alliance market transformation ventures as well as complimentary utility and system benefits administrator acquisition programs are still needed to accomplish regionwide re-lamping.

The Council recognizes that the region may wish to schedule the dispatch of this resource during periods when market prices are high or drought conditions limit resource availability. While delaying the deployment of this resource until "the time is right" may seem at first appealing, the Council does not recommend this approach during the next five years. First, the savings from CFLs could account for just over 25 percent of the Council's annual 120 average megawatt target for dispatchable conservation measures. Any reduction in the savings from this measure will have to be compensated for by increased savings from other measures. Since the Council has not identified any alternative "dispatchable resources" of comparable size and cost (1.7 cents per kilowatt-hour) any such substitution would likely come at a higher cost. Second, the Council believes that sustained and aggressive programs will be needed just to achieve the Council's total CFL savings target. Recent evaluation found that about 80 percent of the lamps sold are immediately installed.[20] Therefore, achieving the Council's five-year target will likely necessitate the deployment of roughly 11 million CFLs annually. That is about 2 million more than were distributed across the region in 2001 during the West Coast Energy Crisis. While this may sound overly aggressive it should be noted that the region was able to ramp up the distribution of CFLs from less than 500,000 to over 9 million in less than a year. Moreover, the typical cost of the most popular CFL is now half of what it was in 2001.

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[15]Findings and Report - Retrospective Assessment of the Northwest Energy Efficiency Alliance, Final Report. Prepared for the Northwest Energy Efficiency Alliance Ad Hoc Retrospective Committee by Summit Blue Consulting and Status Consulting. Portland, Oregon. December 8, 2003.

***Residential Weatherization and HVAC***

The remaining residential sector dispatchable conservation resources are available through the weatherization of existing single family, multifamily and manufactured (mobile) homes. The bulk of these savings comes from installing higher levels of insulation and replacing existing windows with new Energy Star® products. In addition, cost-effective savings in existing homes with forced air furnaces and heat pumps can be captured by sealing the leaks in their air ducts and by making sure the heat pump as the proper refrigerant charge and system air flow.[21] The Council believes that utility and public benefits charge administrator conservation acquisition programs should be the primary mechanism employed to capture these resources. These weatherization programs have a demonstrated track record. However, such programs need to be revised to incorporate duct sealing and heat pump maintenance in the package of efficiency improvements considered for installation in each home.

Table D-4 provides a summary of the Council's recommendations regarding the mix of resource development mechanisms needed to achieve the residential sector's conservation targets. A primary (P) and secondary (S) resource development mechanism is shown for each of the major sources of residential sector conservation. Specific major mechanisms, such as market transformation, regional programs and local acquisition programs are also divided into several subcategories. Within these subcategories Table 7-5 also indicates the type of action (e.g., acquisition payment, product specification or research and development) the Council believes may be needed to develop this sector's conservation potential.

Although the specific mix of mechanisms needed to accomplish the residential sector targets will be determined through the strategic planning process, the Council estimates that Bonneville, the region's utilities and system benefits charge administrators will need to be prepared to invest between $75 and $100 million annually to acquire the 45 - 55 average megawatts of residential sector conservation called for in this Plan. Of this amount approximately 75 to 85 percent will be needed for local acquisition programs, 15 to 25 percent for regional programs, market transformation initiatives, research and development and specifications. The actual split between regional and local budgets should be determined during the strategic planning process based on whether regional or local acquisition payments offer a more efficient and effective method of securing savings from heat pump water heaters and Energy Star appliances.

[21] These measures were not included in the Fourth Power Plan's estimate of conservation opportunities.

**Table D-4 Summary of Council Recommended Residential Sector Conservation Resource Development Mechanisms**

| Measure | Acquisition Mechanism | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Market Transformation | | | | | Regional Program | | | Local Program | |
| | Codes & Standards | MT Venture | National Product Specification | Regional Product Specification | Regional RD&D | Administration | Infrastructure | Acquisition Payments | Administration | Acquisition Payments |
| Heat Pump Conversions | S | S | | Y | S | | | | P | P |
| Heat Pump Upgrades | S | S | | Y | S | | | | P | P |
| PTCS Duct Sealing | S | | | Y | | S | P | | P | P |
| PTCS Duct Sealing and System Commissioning | | | | Y | | S | P | | P | P |
| PTCS Duct Sealing, Commissioning and Controls | | | | Y | S | S | P | | P | P |
| Energy Star - Manufactured Homes | S | P | | Y | | P | | M | | S |
| Energy Star - Multifamily Homes | P | P | | Y | | P | | | S | S |
| Energy Star - Single Family Homes | P | P | | Y | | P | | | S | S |
| Weatherization - Manufactured Home | | | | Y | | | | | P | S |
| Weatherization - Multifamily | | | | Y | | | | | P | S |
| Weatherization - Single Family | | | | Y | | | | | P | S |
| CFLs | | S | Y | | | P | | | | S |
| Refrigerators | S | S | Y | | | | | | | S |
| Clothes Washers | S | S | Y | | | | | | | S |
| Dishwashers | P | S | Y | | | | | | | S |
| Efficient Water Heater Tanks | S | | | Y | | | | | | P |
| Heat Pump Water Heaters | S | P | Y | Y | P | S | | Y | | M |
| Hot Water Heat Recovery | S | P | M | Y | P | | | | | S |
| **P-Primary Agent and/or Near Term Action Needed** | | | **S - Secondary Agent and/or Medium to Long Term Action Needed** | | | **Y= Action or Product Needed** | | **M= Action or Product May Be Needed** | | |

## Commercial-Sector Acquisition Strategies

Several characteristics of the commercial conservation potential are notable. First, about 60 percent of the 20-year conservation potential identified is in lost-opportunity resources that must be captured when buildings are constructed or remodeled and when new or replacement equipment is purchased. These factors point to a relatively larger role for market transformation activities and regionally coordinated acquisition approaches compared to the residential sector.

The conservation potential identified in the commercial sector has several characteristics that suggest a relatively large role for regionally coordinated approaches. First, a large fraction of the savings potential, about 60 percent, is in lost-opportunity measures. Second, a large fraction of the savings potential requires changing practices or services as opposed to simply installing new technology. This practice-oriented characteristic will require significant amounts of education, training and marketing. Third, codes and standards can play an important role in some of the measures where savings result primarily from more efficient equipment such as better AC to DC power converters and commercial refrigeration appliances. Because many of those products are used throughout the country, and the world, the cost of improving efficiency can be shared with others from outside the region, reducing the cost of acquisition. Fourth, only part of the savings potential in new buildings is suitable for adoption in building energy codes. Consequently, the region will need to maintain long-term efforts to improve building design, construction and commissioning practices. In addition, commercial markets for energy efficient products and practices typically span across utility boundaries and state lines. This is true for the vendors, designers, installers, and distributors that need to be influenced as well as commercial-sector business and building owners that operate chains, franchises or multiple establishments.

Over the next five years, the Council recommends, about 40 to 50 average megawatts per year of commercial sector conservation be targeted for development. Region-wide commercial-sector lost-opportunity conservation targets should accelerate from 5 to 15 average megawatts per year between 2005 and 2009. Discretionary targets should be in the range of 35 average megawatts per year. While there is a relatively important role for regionally-administered efforts, in the commercial sector, incentive payments and direct-acquisition approaches through local utilities and public benefits charge administrators will continue to play a key role and will require the largest share of financial requirements. Based on a the kinds of measures and programs identified and estimated programs costs, the Council estimates that majority of annual utility system expenditures would be earmarked for direct acquisition approaches. But, a significant fraction of annual expenditures on commercial conservation should be directed toward regionally coordinated and administered efforts including the market transformation efforts of the Alliance. Coordinated approaches are needed among the utilities, administrators, Bonneville, local, state and federal governments, trade allies, retailers, distributors, manufacturers and entrepreneurs. The need for coordinated and strategic efforts adds to administrative costs, but will provide leverage across markets, minimize duplication of efforts and improve the effectiveness of conservation programs.

Although the specific mix of mechanisms needed to accomplish the commercial sector targets will be determined through the strategic planning process, the Council estimates that Bonneville, the region’s utilities and public system benefits charge administrators will need to be prepared to invest budget between $70 and $100 million annually for five years to acquire the 225 average megawatt five-year commercial sector target called for in this Plan. Of this amount approximately two-thirds will be needed for local acquisition programs. Approximately one-third will be needed for regional programs, market transformation initiatives, codes and standards, research and development, specification development, training, education and other infrastructure needed to facilitate acquisition. The actual split between regional and local budgets should be determined during the strategic planning process.

### Commercial-Sector Lost-Opportunity Resources

About 60 percent of the commercial-sector conservation potential is in lost opportunity resources under the medium forecast. The Council forecasts that under medium growth, typically 50 to 60 million square feet per year of new floor space are added annually in the region and another 20 million square feet undergo renovations significant enough to require compliance with more stringent energy codes. This is something on the order of 3000 new commercial buildings per year and significant renovations on another 2500 existing buildings. The Council recommends that the region gear up to be capturing 85 percent of the available lost-opportunities available by 2017. Under the medium forecast, 85 percent lost-opportunity penetration would amount to about 30 to 35 average megawatts per year of commercial sector lost-opportunity conservation.

These opportunities would benefit from strategic intervention in markets and efficiency efforts focused upstream of the consumer. Many of the lost-opportunity resources will require market transformation activities and regional infrastructure development. Furthermore, significant near-term effort is needed to ramp up conservation activities for commercial sector lost-opportunity resources to levels where penetration reaches 85 percent. Of the lost-opportunity conservation potential identified, about one-third is in new appliances and equipment that can be tapped eventually through efficiency standards. But near-term investments are needed to support development and adoption of the standards and to get efficient products in place absent standards.

The other two-thirds of lost-opportunity potential is in new building design, new and replacement lighting systems and new and replacement HVAC systems and controls. These opportunities require a multi-faceted approach to acquisition including market transformation, education, training, design assistance and pursuit of better building codes and standards. Eventually lighting codes can be upgraded to capture some of this potential. But the majority of savings potential will require near-term market transformation, development of regional infrastructure including training, education, marketing, and market research plus incentives and rebates for consumers, manufacturers or vendors. Table D-5 shows the size and cost characteristics of commercial lost-opportunity measures.

**Table D-5: Commercial Sector Lost-Opportunity Measures**

| Measure | Realistically Achievable Potential in 2025 (MWa) | Weighted Levelized Cost (Cents/kWh) | Benefit Cost Ratio | Weighted Total Resource Capital Cost ($/kWa) | Share of Sector Realistically Achievable Potential |
|---|---|---|---|---|---|
| Efficient AC/DC Power Converters | 156 | 1.5 | 2.7 | $651 | 14% |
| Integrated Building Design | 152 | 2.3 | 4.8 | $2,968 | 14% |
| Lighting Equipment | 101 | 0.3 | 12.1 | $197 | 9% |
| Packaged Refrigeration Equipment | 68 | 1.9 | 1.9 | $1,299 | 6% |
| Low-Pressure Distribution | 47 | 2.7 | 1.6 | $4,641 | 4% |
| Skylight Day Lighting | 34 | 3.4 | 1.6 | $3,420 | 3% |
| Premium Fume Hood | 16 | 3.7 | 1.0 | $4,137 | 2% |
| Municipal Sewage Treatment | 11 | 1.4 | 2.4 | $687 | 1% |
| Roof Insulation | 12 | 1.5 | 2.1 | $2,458 | 1% |
| Premium HVAC Equipment | 9 | 4.3 | 1.2 | $4,060 | 1% |
| Electrically Commutated Fan Motors | 9 | 2.4 | 1.8 | $2,925 | 1% |
| Controls Commissioning | 9 | 3.7 | 1.1 | $3,248 | 1% |
| Variable Speed Chillers | 4 | 3.1 | 1.6 | $5,029 | 0.3% |
| High-Performance Glass | 6 | 3.0 | 1.4 | $5,572 | 0.5% |
| Perimeter Day Lighting | 1 | 6.3 | 0.9 | $7,441 | 0.1% |
| Evaporative Assist Cooling | 0 | | | | 0.0% |
| | | | | | |
| **Total** | **634** | **1.9** | **4.3** | **$1,970** | **58%** |

Six lost-opportunity measures above account for nearly 90 percent of the savings from lost-opportunity measures identified. Table D-6 shows characteristics of these and other commercial sector lost-opportunity measures and estimates for energy savings targets over the 2005-2009 period. These include estimates of the level of activity required for locally and regionally administered aspects of programs. Table D-6 identifies that most of these measures require direct acquisition investments by utilities and public benefits charge administrators as well as regional approaches. Regional approaches include market transformation, development and implementation of codes and standards, establishing regional specifications for measures or practices, developing regional infrastructure, research and development, and in two cases potential regional acquisition payments.

Table D-6 also identifies in what areas new efforts need to be initiated, and where existing efforts need to be continued or expanded. The Council estimates that the amount of funding needed annually for regionally administered programs is significant increase over current expenditure levels. The Council intends to work through the conservation strategic planning process it recommends to put in place mechanisms and funding to acquire this conservation. Suggested acquisition approaches for the remaining lost-opportunity measures are discussed briefly following Table D-6.

## Table D-6 Near-Term Actions for Commercial-Sector Lost-Opportunity Measures

| Commercial-Sector Lost-Opportunity Measures | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Regionally-Administered Activities Needed | | | | | | |
| **Measure** | **Five-Year Target 2005-2009 (MWa)** | **Utility & SBC Acquisition Payments** | **Codes & Standards** | **Market Transformation Ventures** | **Regional or National Product Specs.** | **Regional RD&D** | **Regional Infra-structure Development** | **Regional Acquisition Payments** |
| Efficient AC/DC Power Converters | 12 | Potential | New | New | New | | | Potential |
| Integrated Building Design | 12 | Yes | | Expand | Expand | Expand | Expand | |
| Lighting Equipment | 7.8 | Yes | Continue | New | New | New | Expand | |
| Packaged Refrigeration Equipment | 5.2 | Potential | New | New | New | New | New | Potential |
| Low-Pressure Distribution | 3.6 | Yes | Continue | Expand | New | Expand | Expand | |
| Skylight Day Lighting | 2.6 | Yes | Continue | Continue | Continue | Continue | Continue | |
| Premium Fume Hood | 1.3 | Yes | Continue | New | | New | | |
| Municipal Sewage Treatment | 0.8 | Yes | | Expand | | Continue | Continue | |
| Roof Insulation | 0.9 | Yes | | | | | | |
| Premium HVAC Equipment | 0.7 | Yes | | | Continue | Continue | | |
| Electrically Commutated Fan Motors | 0.7 | | Continue | | | | New | |
| Controls Commissioning | 0.7 | Yes | Continue | Expand | Expand | | Expand | |
| Variable Speed Chillers | 0.3 | Yes | | | | | New | |
| High-Performance Glass | 0.4 | Yes | | Continue | | Continue | | |
| Perimeter Day Lighting | 0.1 | Yes | Continue | | | Continue | | |
| Evaporative Assist Cooling | 0.0 | Potential | Continue | New | New | New | New | |
| **Total** | **49** | | | | | | | |

### *Efficient Power Supplies*

This efficiency opportunity could reduce regional loads in the commercial and residential sectors by about 150 average megawatts in 2025 under medium load growth. The levelized cost of he savings is expected to be less than 1.5 cents per kilowatt-hour when fully deployed. The benefit-cost ratio is about three to one. Initially, program costs will be higher as production volumes are presently low and program costs could equal the capital costs of better power supplies. Eventually, appliance standards could capture the bulk of the savings at very low cost to the utility system or to society. These are lost-opportunity measures. There are many distinct markets for power supplies depending on how they are incorporated into devices, how products are specified and marketed and the structure and location of the manufacturers.

The large potential savings at low cost of efficient AC to DC power converters has recently spurred some national and international efforts aimed at capturing the resource. Initial efforts include standardized test procedures to measure performance of power supplies, design guideline specifications for power supplies in personal computers advanced by Intel, a design competition for efficient power supplies taking place in 2004 with winners to be announced in March 2005. Energy Star specifications are targeted for later in 2004 and efficiency labeling being considered for Energy-Star computers in 2005 which may include power supply specifications or overall computer performance specifications which encourage the use of efficient power supplies in computers. Finally, the state of California is considering mandatory efficiency standards for external power supplies in January of 2006, and more stringent standards in 2008. But additional efforts are needed in the Northwest to realize the full potential of the more efficient technology.

This efficiency opportunity suffers from classic barriers. The markets for both internal and external power supplies are highly competitive based primarily on first cost. The buyers of these devices are predominantly product manufacturers whereas the costs of operation fall on end users and are individually small, providing for little customer-driven demand for efficiency. But, because there are so many of these devices embedded in appliances and buildings, the savings to the power system are large and low cost. To overcome the barriers programs should aim at manufacturers, bulk purchasers and ultimately state level efficiency standards. What is needed is:

- Utility, system benefit charge administrators and Alliance participation in an emerging national buy-down program for desktop computers that contain highly efficient power supplies
- Development and adoption of buy down programs or manufacturer incentives for other high-volume products using power supplies like televisions, VCRs, and computer monitors
- States should adopt mandatory standards for external power supplies consistent with standards that are under consideration in California
- Participation of utilities and efficiency advocates in government labeling and standards discussions and continual improvement in qualifying specifications
- Utility or market transformation programs for high volume purchasers, like government procurement offices, to purchase winning products from the 2004 efficient power supply design competition
- Research and field measurements to better understand the total energy use of plug loads in homes and businesses

Regional and national market transformation efforts are needed in the near term as first steps toward acquisition. Simultaneous efforts will be needed to develop and adopt efficiency standards where applicable. A multi-year effort will be needed and should identify and focus on sub markets that offer significant savings and promising opportunities for effective intervention. The Council expects efforts to improve internal power supplies, which are integral to specific appliances like televisions and video cassette recorders, to require focused efforts for each product class and that these efforts will require cooperative funding of utilities and market-transformation entities from across the country.

***Commercial New Building Integrated Design:***

The Council estimates that approximately one-third of new commercial floor space could benefit form integrated building design. Estimated achievable conservation potential under the medium forecast is about 150 average megawatts in 2025 at a levelized cost of about 2.3 cents per kilowatt-hour and benefits that are about 5 times costs. Five-year conservation targets are about 12 average megawatts under medium growth.

Integrated building design expands the building design team to include owners, developers, architects, major sub-contractors, occupants and commissioning agents and involves them at the very start of a project. The early collaboration of interested parties lays the foundation for creating a high-performance building. Successful programs require training and education of design practitioners, early identification of projects, marketing, and professional services for coordination, facilitation, design and review. It is a change in the design process, as much as the application of efficiency technologies. As a result, the opportunities cannot readily be captured by codes and standards.

The cost of acquiring savings in new buildings through integrated building design programs is approximately equally split between the improving the design process and the incremental costs of more efficient technology. Although it is often the case that the net capital costs of measures is zero due to synergies that result from of the integrated design process like system downsizing.

There are many energy efficiency activities going on today in support of integrated building design. These include the Alliance-supported Better Bricks project and advisor services, support of the day lighting labs, commissioning and building operator certification, training programs and research assistance. The Alliance is also pursuing a target market strategy that includes integrated design, and is currently focusing on new schools, health care, and grocery stores. These efforts should be continued, and modified. The target market strategy should be expanded to other segments of the new building industry going forward. Several regional utilities have new building programs or green building programs that promote integrated building design concepts and fund or offset costs of a design process that optimizes for energy efficiency. But the penetration of integrated building design practices is low, on the order of 5 percent of new floor space.

At the national level, participation in the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) rating system is growing rapidly with over 1000 projects in the registration process. LEED projects can earn points toward a rating in categories of energy efficiency, sustainable sites, water efficiency, materials and resources, indoor environmental quality and design process. While LEED projects do not necessarily employ integrated design processes for energy efficiency, the wide recognition of the rating is appealing to many design teams and owners alike. It is one of the most successful programs at developing interest in better-designed buildings within the new building community. As such it offers an opportunity to engage designers and owners of new buildings and to focus on and improve energy efficiency aspects of new buildings through integrated design. Efforts are underway to improve the energy-efficiency aspects of the LEED rating system. These should be continued. Several utilities in the region and around the country are using LEED as a framework for new building programs and enhancing the energy efficiency aspects of LEED projects.

Also at the national level are the advanced building guidelines for high-performance buildings being developed by the New Buildings Institute. These guidelines and strategies, dubbed E-Benchmark, focus on improving the design process for commercial buildings as well as on specific technologies and practices that improve energy performance. They are designed to be compatible with LEED, and could be a framework for local efficiency programs to foster higher energy performance in buildings.

Changing design practice will take time and continual efforts. Needed activities include:

- Continued training and education of design practitioners
- Developing and deploying strategies to identify and capture integrated design opportunities as they arise so opportunities are not lost
- Building the demand for high-performance buildings among owners and occupants
- Design team collaboration incentives, funding for energy modeling and design charettes and offsetting LEED registration costs
- Incentive payments for adoption of some technologies
- Adopting appropriate integrated design efficiency strategies into building codes
- Integration of operation and maintenance and commissioning practices
- Obtaining and analyzing performance data for high-performance buildings
- Continued research and development of high-performance design practices and technologies

***Commercial New and Replacement Lighting Equipment***

Advances in commercial lighting technology continue to improve system efficacy, which is the light output of lamps and fixtures per unit of energy input. About 100 average megawatts of savings are available by 2025 in new and replacement lighting systems in addition to lighting savings accounted for under integrated building design above.

About one dozen specific technologies and applications are included in this bundle. These measures tend to have low incremental cost in new and replacement lighting situations because higher system efficacy allows for fewer lamps, ballasts and fixtures and because of low incremental labor costs. The total resource cost is further reduced because of lower re-lamping and maintenance costs. The low cost characteristics combined with high customer benefits of lower maintenance costs and better quality and color, mean customers will eventually pick up a large share of the costs of these measures. But first, practitioners must get familiar with the technologies and their application to assure high-quality and long-lasting efficient lighting solutions. Because these are low cost lost-opportunity resources they are high priority. The ultimate goal is to apply these measures to all new buildings and all replace-on-burnout opportunities.

Northwest utilities, public benefits charge administrators have operated lighting programs for new commercial buildings for about a decade. These have included a range of rebates and design assistance focused at owners, vendors, specifiers and customers. Such efforts should continue and be expanded in the future to target all lost-opportunities. In addition, the region now sponsors lighting design labs in Seattle and Portland. These facilities offer expertise, training, workshops and opportunities for designers and owners to mock-up lighting system configurations to see the results.

As the region moves to the newer technologies and applications, education and training of practitioners will be needed. The region would benefit from common specifications for typical systems to simplify applications. This includes continued support for the lighting design labs and maintaining a cadre of well-informed lighting design specialists. Market research and target marketing is needed to identify and capture new and replacement lighting opportunities as they arise and to identify niche markets such as retail task lighting, warehouses and schools. In addition, increasing customer demand for the maintenance savings, and non-energy benefits of these systems will promote rapid deployment of the new measures. There are significant benefits to be gained from regional cooperation. The Council estimates that over the next five years, significant increases will be needed for regionally administered expenditures in addition to local utility and public benefits charge acquisition expenditures. The regionally-administered efforts should be focused on capturing these lighting measures in new and replacement markets including market transformation ventures, regional infrastructure support, market research and marketing, development of regional and national production specifications, and modifications of building codes and equipment standards.

### *Day Lighting in New Commercial Buildings*

The Council estimates about 77 average megawatts of conservation potential from day lighting applications through skylights and perimeter day lighting in new buildings beyond what is required in code. About half is part of the integrated building design measures and the other half is in new buildings that won't be constructed under integrated design processes. Over the 2005-2009 period, targets for both approaches are about 5 average megawatts and should eventually ramp up to 3 to 4 average megawatts per year. Levelized costs for day lighting are estimated to be about 3.5 cents per kilowatt-hour.

The region has recently established four labs that specialize in day lighting in Seattle, Portland, Eugene and Boise. These work to raise awareness and understanding of the benefits of day lighting designs in commercial buildings. The Alliance contributes to funding the labs and their experts so that Northwest architects and other building professionals can use consulting and modeling services to decide how to best incorporate day lighting into a building design and investigate the use of window glazing, electric lighting and controls.

The Council recommends a combination of regionally administered efforts and local utility and public benefits charge administrator incentives to capture the savings from day lighting in new buildings. Significant utility and public benefits charge administrator support of day lighting is needed in the form of direct incentives. In addition, the Council recommends expanding day lighting efforts over the next five years for regionally based efforts including:

- A market transformation venture focused around the owners and developers in building types where day lighting is most appropriate such as large one-story retail, warehouses, schools and certain office applications
- Research on integration issues including HVAC interaction specific to Northwest climates and daylight patterns
- Continued and expanded support for advisor services, labs, and training that is incremental to amounts in Integrated Design
- Development of Northwest-specific day lighting specifications and design protocols
- Integration of day lighting into building codes

### *Packaged Refrigeration Units*

By 2025, loads could be reduced by about 68 average megawatts through more efficient packaged refrigeration devices such as icemakers, reach-in refrigerators and freezers, vending machines, and glass-door beverage merchandisers. Acquisition targets for the 2005-2009 period are about 5 average megawatts as these programs ramp up. Costs are expected to fall as the technologies are embedded in the products, just as cost fell for efficient residential refrigerators. The Council estimates the levelized cost of these savings is about 1.9 cents per kilowatt-hour.

Ongoing efforts include Energy Star rated products, voluntary purchasing guidelines developed by the Federal Energy Management Program (FEMP) and two levels of voluntary standards developed by the Consortium of Energy Efficiency and used in some utility programs. In addition, the state of California has adopted minimum efficiency standards for icemakers, reach-in refrigerators, freezers and beverage merchandisers. California is considering more stringent standards for these appliances and expanding the standards to include walk-in refrigerators and water coolers. Market transformation efforts for efficient vending machines, undertaken with Coke and Pepsi at the national level, are on the verge of being fruitful. These two companies control the lion’s share of the market and are considering specifications that would produce most of the savings from vending machines.

Efforts should focus on market transformation projects at the state, regional and national levels due to the scope of markets for these products. Ultimately standards can be adopted by the Northwest states to assure minimum efficiency levels in most products. The Council recommends that the states adopt the same testing procedures and minimum performance standards as California. This would allow standards to come into play sooner and at lower cost than developing state standards whole cloth. Following California would make for a large west-coast market for these products.

However, the efficiency levels under consideration in California, and proposed by the Council for the Northwest states, are not the most-efficient products on the market. Efforts are also needed to develop a broader range of products that exceed the minimum efficiencies of state standards and to build demand for those products. To promote that goal, acquisition incentives are needed for products that surpass the California standards to stimulate demand and build the case for improving standards over time. These efforts could include rebates and incentives to manufacturers, vendors or perhaps end users for Energy Star products and products that meet the more stringent Tier-2 performance levels suggested by the Consortium for Energy Efficiency (CEE). In addition, regionally based market transformation efforts are needed to work with trade associations & food service consultants, to develop market channels, tailor marketing and incentives to chains and multi-unit purchasers, and to pursue continuous improvements in voluntary standards and national and regional efficient-product specifications.

Costs are expected to decrease sharply as manufacturers incorporate efficiency measures in more of the stock produced. In the near-term, the lion’s share of costs are for direct acquisition. The Council recommends that these efforts be regionally based and be focused upstream of consumers for better leverage.

### *Low-Pressure Distribution Systems*

Total savings potential is about 100 average megawatts by 2025, half through integrated building design and half as stand-alone applications. Levelized costs are estimated at 2.7 cents per kilowatt-hour and the benefit-cost ratio is estimated at 1.6. The measure applies primarily to offices but there are some applications in education, health and "other" sub sectors. Two measures are modeled, under floor air distribution systems and dedicated outside air systems. Both are relatively new techniques in the US but are gaining in acceptance. Both show large savings potential of 1.0 to 1.5 kilowatt-hour per square foot where applicable, lower in schools.

These measures are best approached as design practice changes through market transformation efforts. Regionally administered program costs should be expanded over the next five years. Initial efforts should focus on:

- Demonstration projects including engineering, and evaluation and case studies
- Develop ASHRAE aspects for standards & design protocols
- Research and development to refine designs, collect and review performance data, and tailor to Northwest climates.
- Training and marketing
- Regional specification setting
- Incorporation of efficient design and construction practices into codes

***Electrically Commutated Fan Motors***

The measure has been adopted in the Seattle building codes but should be adopted in statewide codes in Washington, Oregon, Idaho and Montana.

***Light Emitting Diode (LED) Exit Signs***

This technology should also be adopted in state codes where they are not currently required.

***Evaporative Assist Cooling***

The Council has not included savings target for this measure in the draft plan. But the savings potential is significant because of the dry summer climate in much of the region and because the relatively poor performance of stock economizers available in new roof top cooling equipment. In the near term the Council recommends a significant research and pilot project for evaporative-assist cooling.

***Premium Fume Hoods, Premium HVAC Equipment, New Building System Commissioning Measures, Variable Speed Chillers, High-Performance Glazing***

These measures will require regional market transformation or regional infrastructure development with significant utility incentives in the early stages to buy down equipment costs, subsidize design costs.

***High-Performance New and Replacement Glazing in Commercial Buildings***

Improving the thermal efficiency of glass and window frames used in new buildings, over levels required by building codes, can provide economic electric savings potential in some cases. But identifying optimal "better-than-code" glazing for commercial-sector buildings is site- and application-specific. In some cases going beyond code will not produce significant savings. The Council recommends continued efforts to train and educate building designers and specifiers of commercial glazing products on the selection of optimal glazing system for the new building and replacement window markets.  Optimizing the energy and day lighting aspects of glazing should be incorporated as part of the integrated building design process.

### Commercial-Sector Dispatchable Resources

About 40 percent of the 2025 commercial-sector achievable conservation potential is in retrofit measures.  The Council recommends that the region gear up to be capture 35 average megawatts per year of commercial sector dispatchable conservation, or 175 average megawatts over the 2005-2009 period.  Like lost-opportunity measures, retrofit measures require a combination of acquisition approaches.  About one quarter of the savings potential is from lighting measures, and it is relatively low-cost.  The remainder are from a wide variety of measures and practices on various building types and end uses.  Measure levelized costs are generally higher, and benefit-cost ratios generally lower than for commercial-sector lost-opportunity measures.  But total capital and program costs per kilowatt-hour are similar.  Table D-7 lists the characteristics of retrofit measures in order of total savings potential.

**Table D-7: Characteristics of Commercial Sector Retrofit Measures**

| Measure | Realistically Achievable Potential in 2025 (MWa) | Weighted Levelized Cost (Cents/kWh) | Benefit Cost Ratio | Weighted Total Resource Capital Cost ($/kWa) | Share of Sector Realistically Achievable Potential |
|---|---|---|---|---|---|
| Lighting Equipment | 114 | 1.8 | 2.2 | $2,678 | 10% |
| Small HVAC Optimization & Repair | 75 | 3.2 | 1.4 | $1,773 | 6.9% |
| Network Computer Power Management | 61 | 2.8 | 1.3 | $1,008 | 5.6% |
| Municipal Sewage Treatment | 37 | 1.4 | 2.4 | $687 | 3.3% |
| LED Exit Signs | 36 | 2.3 | 1.6 | $445 | 3.3% |
| Large HVAC Optimization & Repair | 38 | 3.7 | 1.2 | $2,995 | 3.5% |
| Grocery Refrigeration Upgrade | 34 | 1.9 | 1.9 | $1,660 | 3.1% |
| Municipal Water Supply | 25 | 3.3 | 1.2 | $690 | 2.3% |
| Office Plug Load Sensor | 13 | 3.1 | 1.2 | $2,664 | 1.2% |
| Pre-Rinse Spray Wash | 10 | 0.6 | 6.6 | $222 | 0.9% |
| LED Traffic Lights | 8 | 1.9 | 1.8 | $3,234 | 0.7% |
| High-Performance Glass | 4 | 3.8 | 1.0 | $5,545 | 0.4% |
| Adjustable Speed Drives | 3 | 4.3 | 1.1 | $7,545 | 0.3% |
| | | | | | |
| **Total** | **459** | **2.5** | **1.8** | **$1,831** | **42%** |

Regionally administered programs are important for retrofit measures, but play a relatively smaller role than utility and public benefits charge administrator direct acquisition approaches. Table D-8 shows the commercial sector retrofit measures and estimated savings targets over the next five years, and where regionally administered efforts need to be initiated, continued or expanded.

## Table D-8 Near-Term Actions for Commercial-Sector Retrofit Measures

| Commercial-Sector Retrofit Measures | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Regionally-Administered Activities Needed | | | | | | |
| **Measure** | **Five-Year Target 2005-2009 (MWa)** | **Utility & SBC Acquisition Payments** | **Codes & Standards** | **Market Transformation Ventures** | **Regional or National Product Specs.** | **Regional RD&D** | **Regional Infra-structure Development** | **Regional Acquisition Payments** |
| Lighting Equipment | 44 | Yes | | New | New | Expand | Expand | |
| Small HVAC Optimization & Repair | 29 | Yes | | Potential | New | Expand | Expand | |
| Network Computer Power Management | 24 | Yes | | Expand | | | Expand | |
| Municipal Sewage Treatment | 14 | Yes | | Expand | | Expand | Expand | |
| LED Exit Signs | 14 | Yes | | | | | | |
| Large HVAC Optimization & Repair | 15 | Yes | | Expand | Expand | Expand | Expand | |
| Grocery Refrigeration Upgrade | 13 | Yes | | | New | | New | Potential |
| Municipal Water Supply | 9.5 | Yes | | Potential | | New | Expand | |
| Office Plug Load Sensor | 5.1 | Yes | | New | | New | New | |
| Pre-Rinse Spray Wash | 3.8 | Yes | New | | | | | |
| LED Traffic Lights | 3.0 | Yes | | | | | | |
| High-Performance Glass | 1.5 | Yes | | | Continue | | | |
| Adjustable Speed Drives | 1.3 | Yes | | Continue | | | | |
| **Total** | **176** | | | | | | | |

### *Lighting Equipment*

The lighting measures in this bundle are similar to their lost-opportunity counter parts. The main differences being the cost of retrofit applications higher due to labor costs and the savings are somewhat higher due to less efficient baseline systems. About 115 average megawatts is available by 2025. Approximately 44 average megawatts should be acquired over the 2005-2009 period. The benefit -cost ratio of retrofit lighting measures is over 2. Levelized costs are relatively low, about 1.8 cents per kilowatt-hour. The adoption of these measures suffers from the same barriers, primarily lack of awareness, training, equipment availability. Retrofit lighting measures would benefit from the regionally administered programs recommended for lost-opportunity lighting measures. This includes education and training of practitioners, common specifications for typical retrofits, continued support for the lighting design labs and maintaining a cadre of well-informed lighting design specialists. The Council estimates that over the next five years, increasaed funding needed for regionally administered expenditures in addition to local utility and public benefits charge acquisition payments. Regional utilities and public benefits charge administrators have operated commercial retrofit lighting programs for more than a decade with good results. These programs should continue and should focus on delivering the new technologies and applications.

### *Small HVAC Optimization & Repair*

Small roof top HVAC systems provide the lion's share of cooling and heating loads in the Northwest. The Council estimates about 75 average megawatts of savings potential is available by 2025, most of it in reduced cooling energy. Levelized costs are about 3.2 cents per kilowatt-hour and the benefit-cost ratio about 1.4. But this is a difficult market. There are many small customers, many vendors of repair service, and several different approaches to improve efficiency. Several pilot scale projects have been tried in recent years, at the Alliance and at several regional utilities, with mixed success on performance and cost. The Council believes the cost-effective savings potential is large and continued efforts are warranted to capture about 30 average megawatts over the 2005-2009 period. Currently three approaches are being tested in the region and in California. One addresses maintenance and repair protocols at the site. A second approach aims at replacing old economizers and controllers with a premium economizer package tailored to Northwest climates. A third approach addresses new equipment by promoting advanced system performance specifications for manufactures of new equipment.

In light of the uncertainty about what approach will perform best, the Council believes that first research is needed on the best approach to take and on field performance of fixes. Then pending results of that research, the region should embark on a strategy to capture the savings as effectively as possible. Near-term regionally administered actions include, research, development of a strategy, and building regional infrastructure to support that strategy. A possible market transformation venture would be to encourage a manufacturer to develop and market an economizer product that is designed to perform well in the Pacific Northwest and California.

### *Network Computer Power Management*

Approximately 62 average megawatts of electricity could be saved at a levelized cost of 2.6 cents per kilowatt-hour through automated control on network personal computers (PC). The five-year target for acquisition is 24 average megawatts. An Alliance project aimed at this target has been largely successful in getting a viable product to market. Capturing the remaining potential may require some amount of utility and public benefits charge administrator incentives, particularly if penetration rates are to be increased. In addition, there may be opportunities to develop a market transformation venture aimed at corporate information technology managers, or expanding the concept to other network-addressable devices commonly used in commerce.

### *Municipal Sewage Treatment*

Between existing and forecast new sewage treatment plant capacity, the Council estimates approximately 37 average megawatts could be saved by optimizing plant operations through relatively simple controls at a levelized cost of 1.4 cents per kilowatt-hour and a benefit-cost ratio of 2.4. The five-year acquisition target is 14 average megawatts. An Alliance project aimed at this target has been largely successful in getting a viable optimization service and some new technology to market. Capturing the remaining potential may require some amount of utility and public benefits charge administrator incentives, particularly if penetration rates are to be increased.

In addition, there may be further opportunities for improving the energy efficiency of treatment regimes through new technological developments that would aid in controlling the biological process of treatment. Such an effort would require about $1 million per year over the next five year in research and market transformation venture capital.

### *Municipal Water Supply*

The estimated 25 average megawatts of electric savings in municipal water supply systems need to be confirmed through research and developed if it proves to be cost-effective and practicable. Near-term efforts should include a research and confirmation agenda with pilot projects. Depending on the outcome of the research and verification, utility and public benefits charge administrator programs would most likely be the vehicle for capturing the savings. Such a project may benefit from some regionally administered marketing, training, and infrastructure development.

### *LED Exit Signs*

This is a proven technology with good product availability, significant labor savings, but small per unit savings. However, the Council estimates there are many exit signs in existing buildings that do not yet use efficient technologies. By 2025 about 36 average megawatts are available at levelized costs of 2.3 cents per kilowatt-hour and a benefit-cost ratio of about 1.6. Acquisition of this measure is most suitable through utility and public benefits charge administrator programs to buy down the replacement cost of the more efficient signage. The acquisition rate of this measure should target 14 average megawatts over the 2005-2009 period.

***Large HVAC Optimization & Repair***

Optimizing the performance of existing buildings, with complex HVAC systems, through commissioning HVAC and lighting controls could save the region nearly 40 average megawatts at a levelized cost of 3.7 cents per kilowatt-hour and a benefit-cost ratio of about 1.2. Capturing these savings requires a cadre of trained experts armed with analytical tools to optimize these complex energy systems. The Alliance has embarked on a market transformation pilot project dubbed Building Performance Systems that aims at developing a market structure that promotes and supports enhanced building operating performance. In partnership with the region's utilities, public benefits administrators, building owners/managers and service providers, key activities for this project include infrastructure development, a building performance services test, and a large-scale pilot. In addition, the Alliance supports building operator certification, the Building Commissioning Association and other regional training and educational infrastructure that support acquiring these savings. These efforts should be continued along with utility and public benefits charge administrator program incentives. The Council estimates that significant regionally administered program expenditures are needed to tap this measure in addition to locally administered incentives and programs.

***Grocery Refrigeration Upgrade***

Retrofitting the refrigeration systems of existing grocery stores to improve efficiency could save the region about 34 average megawatts by 2025 at a levelized cost of 1.9 cents per kilowatt-hour and a benefit-cost ratio of 1.9. These savings come from over one dozen individual measures that include simple and fairly complex retrofits such as high-efficiency case doors, anti-sweat heater controls, efficient motors in cases, floating head pressure control, and strip curtains and automatic door closers for walk-in coolers. This retrofit market overlaps many utility and Public Benefits Charge service territories and would benefit from common specifications for energy efficiency measures. Some training and education of service providers is needed as well as some regional marketing. The Council estimates that locally administered efforts would be modest. But the brunt of expenditures and incentives should be locally administered through utility and public benefits charge administrators.

***High-Performance Glass***

There remain a significant number of electrically heated buildings with single-glazed windows. Some of these are viable to retrofit with new high-performance glazing that will reduce both heating and cooling loads. The Council estimates about 4 average megawatts could be saved by 2025 by retrofitting the windows in these buildings and selecting new glazing to minimize heating and cooling energy use. Window retrofits on gas-heated buildings with electric cooling do not appear to be cost-effective. This measure is primarily a locally administered program that will require some design assistance in selecting appropriate glazing as well as providing incentives to do the retrofits.

***Office Plug Load Sensor, LED Traffic Lights, Pre-Rinse Spray Valves and Adjustable Speed Drives***

These measures together could reduce 2025 energy loads by nearly 30 average megawatts. The measures are best captured through locally administered programs. State codes can be adopted for pre-rinse spray valves.

## Irrigated Agriculture Sector

### Agricultural-Sector Lost Opportunity Resources

The Council did not identify any potential lost opportunity conservation resources in the Irrigated Agriculture Sector. However, this does not mean that all new irrigation systems are being designed to capture all cost-effective energy efficiency opportunities. While competitive economic and environmental pressures certainly encourage the use of more energy and water efficient irrigation systems, farmers, due to capital or other constraints, do not always install the most efficient systems. Utility, public benefits charge administrators and federal and state agricultural extension service education and technical assistance programs are still needed to help farmers and irrigation system hardware vendors design energy efficient systems.

### Agricultural-Sector Dispatchable Resources

The Council believes that utility and public benefits charge administrator acquisition programs are best suited to capture the five average megawatts of savings targeted per year in existing irrigation systems. Over the course of the past two decades Bonneville, along with many of its utility customers with significant irrigation loads have operated irrigation system efficiency improvement programs. These programs will need to be significantly expanded to attain the Council's regional target.

## Industrial Sector Acquisition Strategies

The Council believes that the 35 average megawatts of energy savings per year target for the industries in the region is best accomplished through closing coordinated utility and public benefits charge administrator acquisition programs and regional market transformation programs.

Several industrial market transformation projects have been operated by the Alliance. These include projects that impact compressed air and motor management systems commonly used across many industries. The Alliance has also targeted specific technologies used in Northwest industries including pneumatic conveyors common in the wood products industry, refrigeration systems for cold storage warehouses, sewage treatment and others. Utilities and SBC administrators have developed programs that support these market transformation efforts. Bonneville and the region's utilities have developed programs that purchase energy savings from industrial customers, that rebate specific technologies, or that develop customer-specific programs tailored to meet the needs of both parties. These approaches should continue.

Industrial conservation measures generally have relatively short lifetimes because of the rapid rate of change in production facilities. So few conservation measures qualify as lost-opportunity measures because they exceed the life of the planning period. But in practice, many of the opportunities to improve efficiency in the industrial sector are associated with changes in production techniques, products produced, plant modernization, or changes required for improving product quality, quality control and even safety or environmental compliance. Taking advantage of these opportunities to improve energy efficiency is important. The Council believes these windows of potential influence should be considered as lost-opportunities because in a practical sense, the associated savings are not available if not captured during the natural process of industrial change and modernization.

Successful development of industrial-sector energy efficiency depends on developing the infrastructure and relationships between program and plant staff.  A network of consultants with appropriate technical expertise is needed.  This expertise is available for motor management and compressed air programs.  But for other measures, such as motor system optimization and industrial lighting design, where access to experienced engineers and designers is more critical, the identification and/or development of the support network will require time and effort.  A mix of market transformation ventures, regional infrastructure development, and local program offerings from rebates to purchased savings will be needed to realize this source of low-cost energy efficiency potential.  Stable funding of utility acquisition investments is needed so that industrial customers can coordinate their capital budgeting process with utility financial support.  Regional market transformation initiatives that focus on changing industrial energy management practices are also needed to ensure that efficiency investment opportunities are integrated into corporate productivity goals.

The Council, Bonneville, the Alliance, utilities, and SBC administrators should work with the regions industries, industrial trade associations and industrial service providers to develop and implement a strategy to tap industrial conservation over the next decade.

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# Conservation Cost-Effectiveness Determination Methodology

## CONSERVATION COST-EFFECTIVENESS

As with all other resources, the Council uses its portfolio model to determine how much conservation is cost-effective to develop.[1] The portfolio model is designed to compare resources, including conservation on a "generic" level. That is, it does not model a specific combined cycle gas or coal plant nor does it model specific conservation measures or programs. In the case of conservation, the model uses two separate supply curves. These supply curves, one for discretionary resources and a second for lost opportunity resources, depict the amount of savings achievable at varying costs. In order to capture the impact of variations in wholesale market prices during the day and through the year have on conservation's value, the savings in these two supply curves are allocated to "on-peak" and "off-peak" periods for each quarter of the year. This allocation is done based on the collective savings-weighted load shape of the individual measures in each of these supply curves.

However, it is not possible to determine individual measure or program cost-effective using the Council's portfolio model. Run time constraints limit the number of conservation programs the portfolio model can consider. The portfolio model cannot consider individual programs for every measure and every specific load shape, and perform a measure-specific benefit-cost ratio for each sub-component of conservation. In addition, conservation provides other benefits that are not accurately captured by the portfolio model.

First, unlike generating resources, conservation savings can defer the need to expand distribution and transmission networks. While the Council attempts to capture these benefits by adjusting the levelized cost of the aggregate supply curves, the portfolio model does not evaluate each measure's specific load shape and therefore does not accurately reflect that measure's impact on the need to expand transmission and distribution systems. Second, some conservation measures, for example high efficiency clothes washers that save both water and electricity, provide "non-energy system" benefits to consumers. Because of programming constraints, the levelized costs of conservation used in the portfolio model are not adjusted for non-energy benefits that accrue to the customers. Therefore, to determine whether a specific conservation measure or package of measures is regionally cost-effective requires the Council to compare the present value of each measure's benefits to the present value of its life cycle costs based on its specific benefits and costs. Benefits

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[1] The Act defines regional cost-effectiveness as follows: "Cost-effective", when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers <u>at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource</u>, or any combination thereof. (Emphasis added). Under the Act the term "system cost" means an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and such quantifiable environmental costs and benefits as are directly attributable to such measure or resource. The Council has interpreted the Act's provisions to mean that in order for a conservation measure to be cost-effective the discounted present value of all of the measure's benefits should be compared to the present value of all of its costs.

include energy and capacity cost savings, local distribution cost savings and the 10 percent credit given conservation in the Northwest Power Act and any quantifiable non-energy benefits.[2]

## Benefit-to-Cost Ratio

The costs included in the Council's analyses are the sum of the total installed cost of the measure, program administrative costs and any operation and maintenance costs (or savings) associated with ensuring the measure's proper functioning over its expected life. The benefit-to-cost ratio of a measure is the sum of the present value benefits divided by the sum of the present value costs. Any measure that has a benefit-to-cost ratio of 1.0 or greater is deemed to be regionally cost effective. Those measures that pass this screening step are then grouped into "programs. The cost of this package of measures is then increased to account for program administrative expenses to estimate whether the overall package is regionally cost-effective.[3] If the "program" package has a benefit-to-cost ratio of less than 1.0 then the most expensive measures are removed from the package until the program's benefits equal or exceed its costs.

## The Value of Conservation

Part of the value of a kilowatt-hour saved is the value it would bring on the wholesale power market and part of its value comes from deferring the need to add distribution and/or transmission system capacity. This means that the marginal "avoided cost" varies not only by the time of day and the month of the year, but also through time as new generation, transmission and distribution equipment is added to the power system. The Council's cost-effectiveness methodology starts with detailed information about when the conservation measure produces savings and how much of these savings occur when distribution and transmission system loads are at their highest. Each measure's annual savings are evaluated for their effects on the power system over the 8,760 hours in a year and over the twenty years in the planning period.

The Northwest's highest demand for electricity occurs during the coldest winter days, usually during the early morning or late afternoon. Savings during these peak periods reduce the need for distribution and transmission system expansion. Electricity saved during these periods is also more valuable than savings at night during spring when snow melt is filling the region's hydroelectric system and the demand for electricity is much lower. However, since the Northwest electric system is linked to the West Coast wholesale power market, the value of the conservation is no longer determined solely by regional resource cost and availability.

### Value of Energy Saved

Given the interconnected nature of the West, regional wholesale power prices reflect the significant demand for summer air conditioning in California, Nevada and the remainder of the desert

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

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

Southwest. Consequently, wholesale power prices are significantly higher during the peak air conditioning season in July and August than they are during the remainder of the year. As a result, a kilowatt-hour saved in a commercial building in the afternoon in the Pacific Northwest may actually displace a kilowatt-hour of high-priced generation in Los Angeles on a hot August day. Whereas a kilowatt-hour saved in street lighting might displace a low-cost imported kilowatt-hour on a night in November.

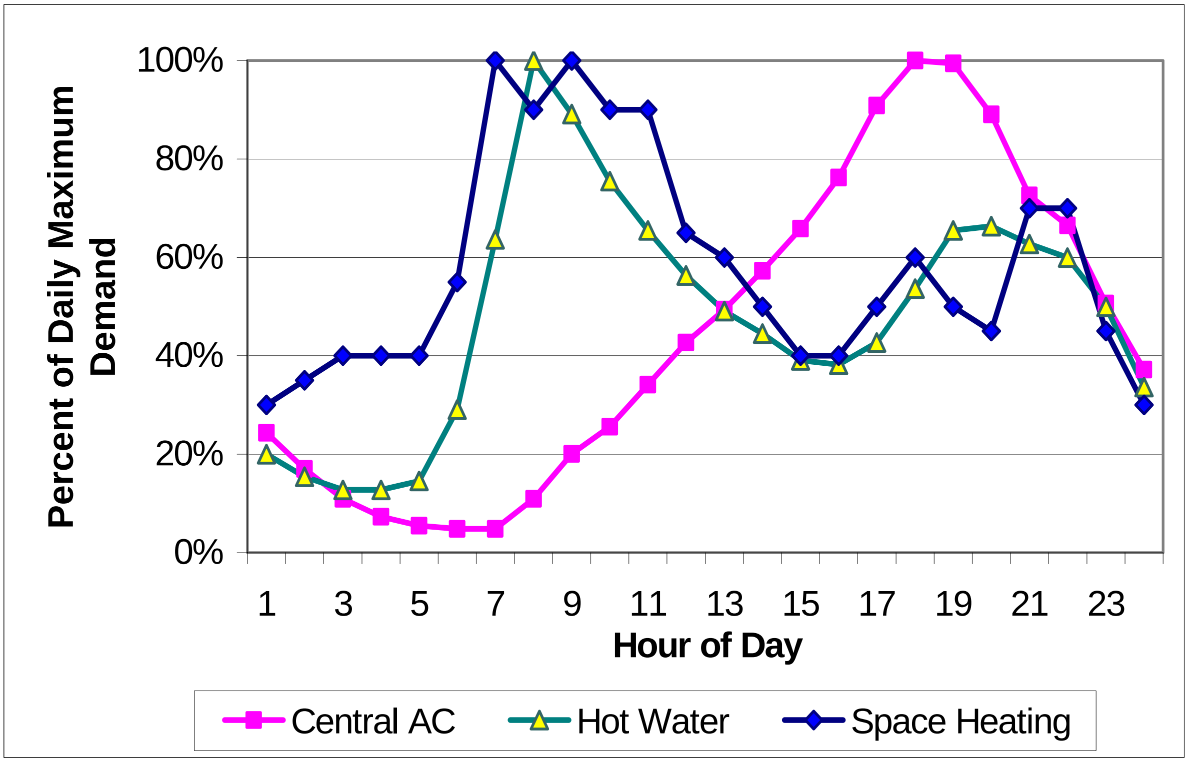


**Figure E-1: Hour Load Profile for Residential Central Air Conditioning Water Heating and Space Heating Conservation Savings**

As noted previously, in addition to its value in offsetting the need for generation during the hours it occurs, conservation also reduces the need to expand local power distribution system capacity. Figure E-1 shows typical daily load shape of conservation savings for measures that improve the efficiency of space heating, water heating and central air conditioning in typical new home built in Boise. The vertical axis indicates the ratio (expressed as a percent) of each hour's electric demand to the maximum demand for that end use over the course of a typical day. The horizontal axis shows the hour of the day, with hour "0" representing midnight.

As can be seen from inspecting Figure E-1, water heating savings increase in the morning when occupants rise to bathe and cook breakfast, then drop while they are away at work and rise again during the evening. Space heating savings also exhibit this "double-hump" pattern. In contrast, central air conditioning savings increase quickly beginning in the early afternoon, peaking in late afternoon and decline again as the evening progresses and outside temperatures drop.

The Council's forecast of future hourly wholesale market power prices vary significantly over the course of a typical summer day and less significantly over the course of a winter day. Figure E-2 shows the average levelized "on peak" and "off peak" wholesale market prices at the Mid-Columbia trading hub for January and August. As can be seen from Figure E-2, summer "on-peak" savings are far more valuable than those that occur either "off-peak" during the summer or either "on" or "off-peak" during the winter.

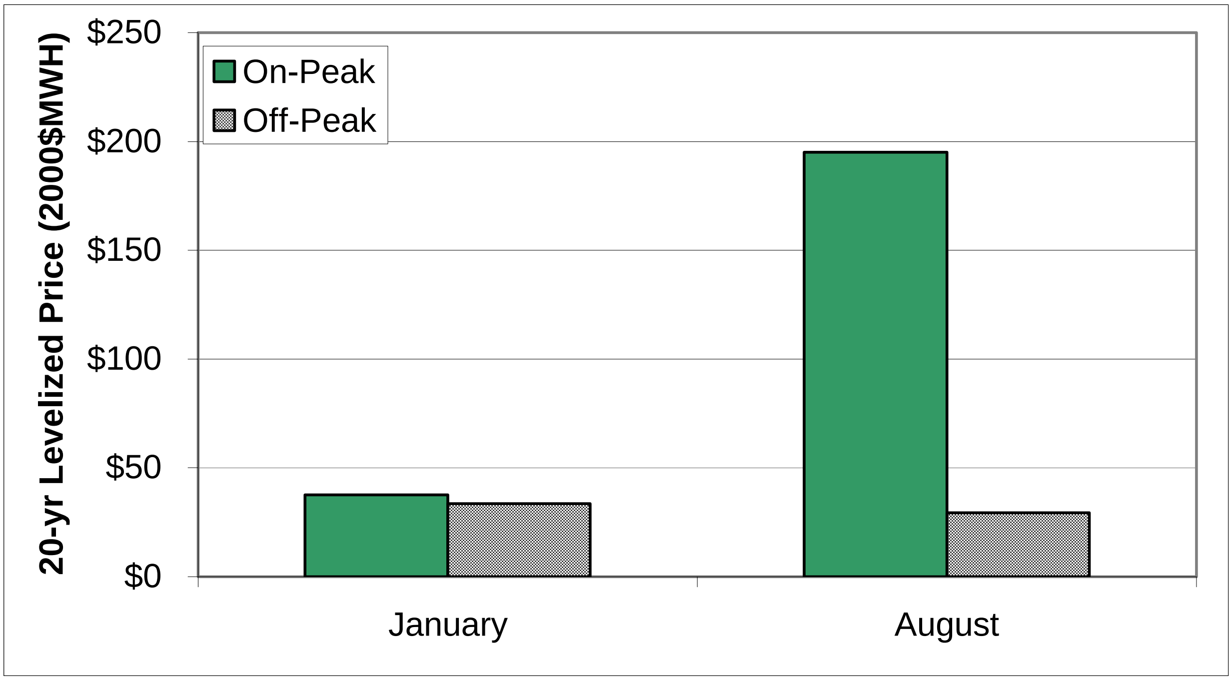


**Figure E-2: Forecast Levelized "On" and "Off-Peak" Wholesale Power Market Prices for January and August at Mid Columbia Trading HUB**

In order to capture this differential in benefits, the Council computes the weighted average time-differentiated value of the savings of each conservation measure based on its unique conservation load shape. Figure E- 3 shows an illustrative example of the levelized avoided cost by month compared to the monthly distribution of central air conditioning and space heating savings. Each month's savings are valued at the avoided cost for that time period based on the daily and monthly load shape of the savings. The weighted value of all time periods' avoided costs establishes the value of the kilowatt-hour portion of the energy savings.

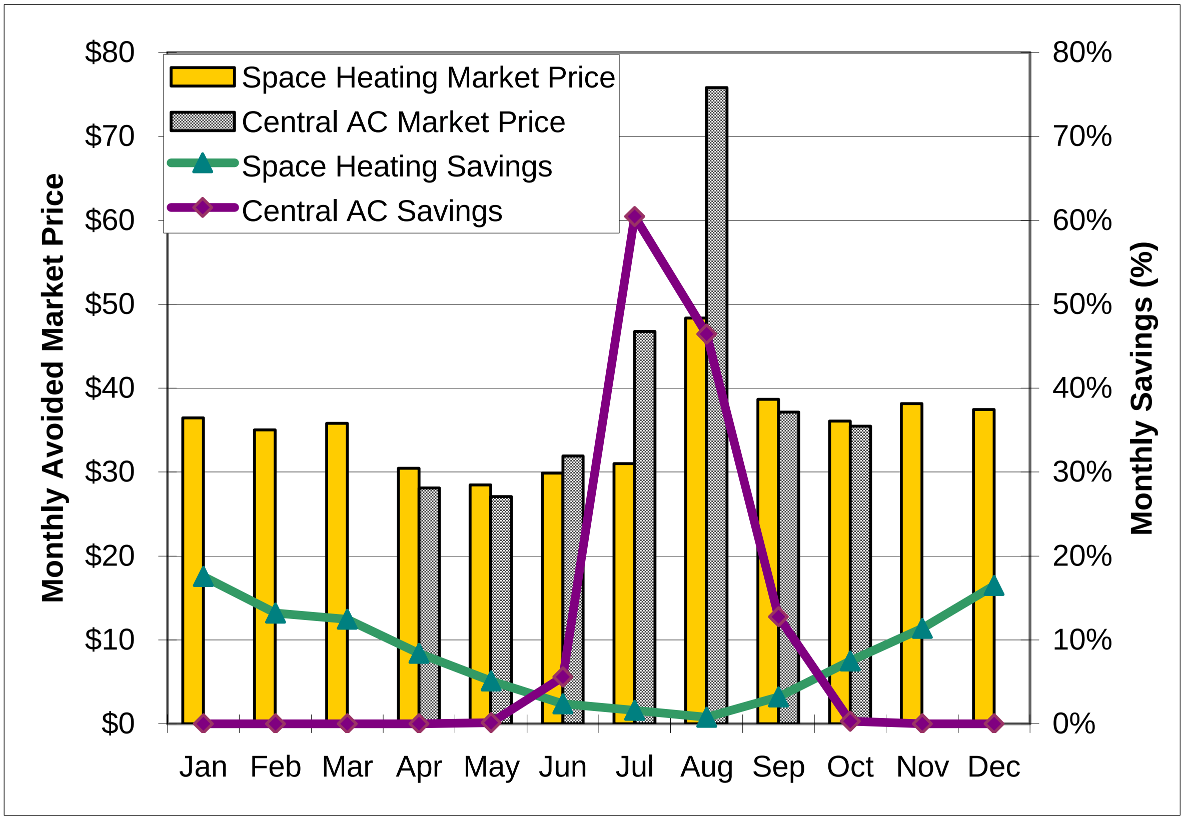


**Figure E-3: Illustrative Levelized Wholesale Market Price by Month Compared to Monthly Energy Savings for Space Heating and Central Air Conditioning**

An inspection of Figure E-3 reveals that the cost-effectiveness limit for air conditioning will be higher than for space heating because wholesale market prices for electricity are higher at the times when air conditioning energy is saved. In this example, the "cost-effectiveness limit" for a conservation measure that produced savings shaped like those for residential central air condition would be 8.8 cents per kilowatt-hour compared to just 3.7 cents per kilowatt-hour if its savings were shaped like residential space heating.

Forecast of future wholesale power market prices are subject to considerable uncertainty. Therefore, in order to determine a more "robust" estimate of a measure's cost-effectiveness it should be tested against a range of future market prices. Although the Council currently uses its "base case" AURORA® model forecast of future wholesale market prices to determine conservation cost-effectiveness, the Council is reviewing its analytical system to determine whether it is feasible to use the portfolio model's distribution of future market prices rather than a single market price forecast. In the interim, the value of conservation savings determined using the "base case" AURORA® market price forecast should be viewed as conservative since this value does not incorporate any hedge against future market price volatility.

### Value of Deferred Transmission and Distribution Capacity

In addition to its value in offsetting the need for generation, conservation also reduces the need to expand local power distribution system capacity. The next step used to determine conservation's cost effectiveness is to determine whether the installation of a particular measure will defer the installation or expansion of local distribution and/or transmission system equipment. The Council recognizes that potential transmission and distribution systems cost savings are highly dependent upon local conditions. However, the Council relied on data obtained by its Regional Technical Forum (RTF) from the Oregon Public Utilities Commission to develop a "default" estimate of avoided transmission and distribution costs. Table 6 presents data collected from PacifiCorp and Portland General Electric (PGE) based on their filings in Oregon. Information from Snohomish County Public Utility District (Snohomish PUD) on distribution system costs only is also included in this table.

**Table E-1: Utility Specific Avoided Costs for Transmission and Distribution**

| COMPANY | TRANSMISSION | DISTRIBUTION | TOTAL |
|---|---|---|---|
| PacifiCorp | $21.40/kW-yr | $57.59/kW-yr | $78.99/kW-yr |
| PGE | $7.18/kW-yr | $15.40/kW-yr | $22.58/kW-yr |
| Snohomish PUD | (N/A) | $9.50/kW-yr | (N/A) |

From the information collected, the RTF chose as its "default" assumption a value of $20 per kilowatt year as the avoided cost of local utility transmission and distribution avoided cost. The RTF also chose a “default” value of $3 per kilowatt year for avoided transmission system expansion cost. The present value of avoiding these investments is included as part of the wholesale transmission and local distribution system benefits of conservation and distributed renewable resources.

As discussed above, due to the interconnected nature of the West coast wholesale power market, conservation measures that reduce consumption during the summer air conditioning season are the most valuable. In contrast, throughout most of the Northwest region measures conservation measures that reduce peak demand during the winter heating season are of more value to the region’s local distribution systems and to its wholesale transmission system. This is because these systems must be designed and built to accommodate “peak demand” which occurs in winter. If a conservation measure reduces demand during these periods of high demand it reduces the need to expand distribution and transmission system capacity.

In order to determine the benefits a conservation measure might provide to the region’s transmission and distribution system it is necessary to estimate how much that measure will reduce demand on the power system when regional loads are at their highest. The same conservation load shape information that was used to estimate the value of avoided market purchases is also used to determine the “on-peak” savings for each conservation measure. This varied from zero value for central air conditioning to 1.8 cents per kilowatt-hour for residential space heating.

### Value of Non-Power System Benefits

In addition to calculating the regional wholesale power system and local distribution system benefits of conservation the Council analysis of cost-effectiveness takes into account a measure’s other non-power system benefits. For example, more energy efficient clothes washers and dishwashers save significant amounts of water as well as electricity. Similarly, some industrial efficiency improvements also enhance productivity or improve process control while others may reduce operation and maintenance costs. Therefore, when a conservation measure or activity provides non-power system benefits, such benefits should be quantified (e.g., gallons of water savings per year and where possible an estimate of the economic value of these non-power system benefits should be computed. These benefits are added to the Council’s estimate of the value of energy savings to the wholesale power system and the local electric distribution systems when computing total system/societal benefits.

### Regional Act Credit

The Northwest Power Act directs the Council and Bonneville to give conservation a 10 percent cost advantage over sources of electric generation. The Council does this by adding 10 percent to the AURORA® model forecast of wholesale market power prices and to its estimates of capital costs savings from deferring electric transmission and distribution system expansion when estimating benefit-to-cost ratios.[4]

## Comparative Examples of Cost-Effectiveness Limits

Table E-2 shows the levelized cost for a sample of conservation measures that would produce a Total Resource Cost benefit-to-cost ratio of 1.0 based on avoided wholesale market purchases and deferred capital investments for transmission and distribution. As can be seen from a review of Table E-2 the "cost-effectiveness" limit ranges from 3.7 cents per kilowatt-hour for more efficient street and area lighting to 8.8 cents per kilowatt-hour for savings from efficiency improvements in window air conditioners when transmission and distribution benefits are considered. When these benefits are not considered the range extends from 3.3 cents per kilowatt-hour up to 7.0 cents per kilowatt-hour. These ranges are completely attributable to the load shape of each measures savings. In Table E-2 measure life is assumed to be 20 years for all measures for purposes of comparison. Actual measure lives used by the Council differ.

While the Act's 10 percent credit for conservation is included in the values shown in Table E-2 all measures shown in the table are assumed to have no non-energy benefits. As mentioned previously, some measures such as residential clothes washers provide the region with substantial non-energy benefits. One of the reasons high efficiency clothes washers save electricity is that they use less hot water. Consequently, they also use less detergent as well as reduce the amount of wastewater that needs to be treated. The Council includes these additional non-energy benefits in its calculation of the Total Resource Cost effectiveness. In the case of residential clothes washers, this increases the "cost-effectiveness limit" from 5.3 cents per kilowatt-hour to 12.1 cents per kilowatt-hour.

## Cost-Effectiveness Limits and Power System Acquisition Costs

The Council uses Total Resource Cost as its measure of regional cost-effectiveness. It selected this metric because it attempts to account for all of a measure's costs and benefits, regardless of who pays or receives them. Ignoring a consumer's share of the cost of installing a conservation measure would understate its true cost to the region. Alternatively, ignoring a consumer's savings in operation and maintenance cost or reduced water consumption would understate a conservation measures actual benefits. Unfortunately, the distribution of conservation's costs and benefits among the region's consumers is rarely perfectly aligned. For example, the non-energy benefits accrue to the consumer purchasing the clothes washer and not to the region's power system. Therefore, while electricity savings from high efficiency clothes washers (and other similar measures) should be

[4] The Council's Portfolio analysis model uses levelized cost, rather than benefit-to-cost ratio to as its measure of cost-effectiveness when testing conservation development strategies. In its portfolio analysis process the Council eliminates from consideration any resource plans that do not develop at least the level of conservation that is consistent with the Act's requirement to provide conservation with a 10 percent premium over other resources.

viewed as regionally cost-effective, the power system's maximum contribution to the acquisition of these savings should be limited by the benefits provided by electricity savings.

**Table E-2: Cost-Effectiveness Limits for Illustrative Conservation Resources**[5]

| Conservation Resource Category | Cost-Effectiveness Limit w/ Transmission and Distribution Benefits (Cents/kWh) | Cost-Effectiveness Limit w/o Transmission and Distribution Benefits (Cents/kWh) |
|---|---|---|
| Street & Area Lighting | 3.7 | 3.3 |
| Commercial - Existing Small Office and Retail Building Envelope Measures | 4.1 | 3.5 |
| Flat Load Profile | 4.2 | 3.9 |
| Commercial Lighting - New Small Office, Gas Heating | 4.3 | 3.8 |
| Agricultural - Dairy Milking Barn, Electric Hot Water | 4.3 | 3.8 |
| Residential Refrigerators | 4.4 | 4.0 |
| Agricultural - Dairy Milking Barn, Milking Machine Pumps (VFD) | 4.4 | 4.0 |
| Industrial - Primary Aluminum Smelting | 4.4 | 3.9 |
| Industrial - Pulp & Paper (SIC 26) | 4.5 | 4.0 |
| Industrial - Lumber & Wood Products (SIC 24) | 4.5 | 4.1 |
| Residential Lighting | 4.5 | 3.9 |
| Commercial Lighting - New Small Office, Air Source Heat Pump Heating and Cooling | 4.6 | 4.0 |
| Residential Freezers | 4.6 | 4.1 |
| PNW System Load Shape | 4.6 | 4.1 |
| Industrial - Food Processing (SIC 20) | 4.6 | 4.1 |
| Commercial Lighting - New Warehouse - Top Daylight, Unspecified Heating Fuel | 4.6 | 4.0 |
| Residential Space Heating - New Homes | 4.8 | 3.3 |
| Residential Domestic Water Heating | 4.9 | 4.0 |
| Commercial Lighting - New Large Retail, Electric Resistance Heating | 4.9 | 4.4 |
| Industrial - Generic Plant with One Shift | 5.2 | 4.6 |
| Commercial Lighting - New Large Office, Air Source Heat Pump Heating and Cooling | 5.3 | 4.7 |
| Residential Clothes Dryers | 5.3 | 4.2 |
| Residential Clothes Washers | 5.3 | 4.2 |
| Agricultural - Irrigation | 5.5 | 4.7 |
| Commercial Lighting - New Hotel, Electric Resistance Heating | 5.5 | 5.1 |
| Commercial Lighting - Existing School, Electric Resistance Heating | 5.9 | 5.5 |
| Commercial Lighting - New School - Top daylight, Unspecified Fuel | 6.0 | 5.4 |

[5] The values in this table assume a 20 year measure life, the Council's medium market price forecast and that the measures are financed at 4% real interest over 15 years using a 4% real discount rate. Dollars are year 2000. In computing the regional benefit-to-cost ratios the Act's 10% conservation credit has been included. However none of these measures are assumed to produce any non-energy benefits.

| | | |
|---|---|---|
| Solar Domestic Water Heating - Summer Peaking Solar Zone 3 | 6.1 | 6.0 |
| Commercial Lighting - New Large Office, Electric Resistance Heating | 6.2 | 5.7 |
| Residential Cooking | 6.2 | 4.1 |
| Customer Side Photovoltaic - Summer Peaking Solar Zone 1 | 6.3 | 5.5 |
| Commercial Lighting - Existing Health Care Facility, Electric Resistance Heating | 6.9 | 6.5 |
| Commercial - Existing Small Office and Retail Building Central Air Conditioning Efficiency Improvements | 7.3 | 5.9 |
| Commercial Lighting - New Health Care Facility, Electric Resistance Heating | 7.4 | 7.0 |
| Residential Central Air Conditioning Regional Average | 7.7 | 6.3 |
| Residential Window Air Conditioning - Cooling Zone 2 | 8.8 | 7.4 |

# MODEL CONSERVATION STANDARD

## INTRODUCTION

As directed by the Northwest Power Act, the Council has designed model conservation standards to produce all electricity savings that are cost-effective for the region. The standards are also designed to be economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to capturing all cost-effective power savings while maintaining consumer economic feasibility, the Council believes the measures used to achieve the model conservation standards should provide reliable savings to the power system. The Council also believes actions taken to achieve the standards should maintain, and possibly improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles, and so forth) found in typical buildings constructed before the first standards were adopted in 1983.

The Council has adopted six model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions, and the standard for conservation programs not covered explicitly by the other model conservation standards.[1]

## THE MODEL CONSERVATION STANDARDS FOR NEW ELECTRICALLY HEATED RESIDENTIAL AND COMMERCIAL BUILDINGS

The region should acquire all electric energy conservation measure savings from new residential and new commercial buildings that have a benefit-to-cost ratio greater than one when compared to the Council's forecast of future regional power system cost[2]. The Council believes that at least 85 percent of all regionally cost-effective savings in new residential and commercial buildings are practically achievable. The Council finds that while significant progress has been made toward improving the region's residential and commercial energy codes these revised codes will not capture at least 85 percent of the regionally cost-effective savings in these sectors. The Council's analysis indicates that further improvements in existing residential and commercial energy codes would be both cost-effective to the regional power system and economically feasible for consumers.

The Council is committed to securing all regionally cost-effective electricity savings from new residential and commercial buildings. The Council believes this task can be accomplished best through a combination of continued enhancements and enforcement of state and local building codes and the development and deployment of effective regional market transformation efforts.

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1 This chapter supersedes the Council's previous model conservation standards and surcharge methodology.

2 The term "system cost" means an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource. [Northwest Power Act, §3(4)(B), 94 Stat. 2698-9.]

Bonneville and the region's utilities should support these actions. The Council has established four model conservation standards affecting new buildings. These standards are set forth below:

## The Model Conservation Standard for New Site Built Electrically Heated Residential Buildings and New Electrically Heated Manufactured Homes

The model conservation standard for new single-family and multifamily electrically heated residential buildings is as follows: New site built electrically heated residential buildings are to be constructed to energy-efficiency levels at least equal to those that would be achieved by using the illustrative component performance paths displayed in Table F-1for each of the Northwest climate zones.[3] New electrically heated manufactured homes regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983) are to be built to energy-efficiency levels at least equal to those that would be achieved by using the illustrative component performance paths displayed in Table F-2 for each of the Northwest climate zones. The Council finds that measures required to meet these standards are commercially available, reliable and economically feasible for consumers without financial assistance from Bonneville.

It is important to remember that these illustrative paths are provided as benchmarks against which other combinations of strategies and measures can be evaluated. Tradeoffs may be made among the components, as long as the overall efficiency and indoor air quality of the building are at least equivalent to a building containing the measures listed in Tables F-1 and F-2.

## The Model Conservation Standard for Utility Conservation Programs for New Residential Buildings

The model conservation standard for utility conservation programs for new residential buildings is as follows: Utilities should implement programs that are designed to capture all regionally cost-effective space heating, water heating and appliance energy savings. Efforts to achieve and maintain a goal of 85 percent of regionally cost-effective savings should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness, all costs, including utility administrative costs and financial assistance payments, should be taken into account. This standard applies to site-built residences and to residences that are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983).

There are several ways utilities can satisfy the model conservation standard for utility conservation programs for new residential buildings. These are:

1. Support the adoption and/or continued enforcement of an energy code for site-built residential buildings that captures all regionally cost-effective space heating, water heating and appliance energy savings.
2. Support the revision of the National Manufactured Housing Construction and Safety Standards for new manufactured housing so that this standard captures all regionally cost-effective space heating, water heating and appliance energy savings.

[3] The Council has established climate zones for the region based on the number of heating degree-days as follows: Zone 1: less than 6,000 heating degree days; Zone 2: 6,000-7,500 heating degree days; and Zone 3: over 8,000 heating degree days.

3. Implement a conservation program for new electrically heated residential buildings. Such programs may include, but are not limited to, state or local government or utility sponsored market transformation programs (e.g., Energy Star®), financial assistance, codes/utility service standards or fees that achieve all regionally cost-effective savings, or combinations of these and/or other measures to encourage energy-efficient construction of new residential buildings and the installation of energy-efficient water heaters and appliances, or other lost-opportunity conservation resources.

| Table F-1:Illustrative Paths for the Model Conservation Standard for New Site Built Electrically Heated Residential Buildings | | | |
|---|---|---|---|
| | Climate Zone | | |
| **Component** | **Zone 1** | **Zone 2** | **Zone 3** |
| **Ceilings** | | | |
| • Attic | R-38 (U-0.031)[a] | R-38 (U-0.031)[a] | R-49 (U-0.020)[b] |
| • Vaults | R-38 (U-0.027) | R-38 (U-0.027) | R-38 (U-0.027) |
| **Walls** | | | |
| • Above Grade[c] | R-21 Advanced (U-0.051) | R-21 Advanced (U-0.051) | R-21 Advanced (U-0.051) |
| • Below Grade[d] | R-19 | R-19 | R-19 |
| **Floors** | | | |
| • Crawlspaces and Unheated Basements | R-30 (U-0.029) | R-30 (U-0.029) | R-38 (U-0.022) |
| • Slab-on-grade - Unheated[e] | R-10 to 4 ft or frost line whichever is greater | R-10 to 4 ft or frost line whichever is greater | R-10 to 4 ft or frost line whichever is greater |
| • Slab-on-grade - Heated | R-10 Full Under Slab | R-10 Full Under Slab | R-10 Full Under Slab |
| Glazing[f] | R-2.9 (U-0.35) | R-2.9 (U-0.35) | R-2.9 (U-0.35) |
| Maximum Glazed Area (% floor area)[g] | 15 | 15 | 15 |
| Exterior Doors | R-5 (U-0.19) | R-5 (U-0.19) | R-5 (U-0.19) |
| Assumed Thermal Infiltration Rate[h] | 0.35 ach | 0.35 ach | 0.35 ach |
| Mechanical Ventilation[i] | See footnote h, below | | |
| Service Water Heater[j] | Energy Factor = 0.93 | | |

[a] R-values listed in this table are for the insulation only. U-factors listed in the table are for the full assembly of the respective component and are based on the methodology defined in the *Super Good Cents Heat Loss Reference—Volume I: Heat Loss Assumptions and Calculations and Super Good Cents Heat Loss Reference—Volume II—Heat Loss Coefficient Tables*, Bonneville Power Administration (October 1988).

[b] Attics in single-family structures in Zone 3 shall be framed using techniques to ensure full insulation depth to the exterior of the wall. Attics in multifamily buildings in Zone 3 shall be insulated to nominal R-38 (U-0.031).

[c] All walls are assumed to be built using advanced framing techniques (e.g., studs on 24-inch centers, insulated headers above doors and windows, and so forth) that minimize unnecessary framing materials and reduce thermal short circuits

[d] Only the R-value is listed for below-grade wall insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for below-grade insulation should be taken from the Super Good Cents references listed in footnote "a" for the appropriate soil condition and building geometry.

[e] Only the R-value is listed for slab-edge insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for slab-edge insulation should be taken from the Super Good Cents references listed in footnote "a" for the appropriate soil condition and building geometry and assuming a thermally broken slab.

[f] U-factors for glazing shall be determined, certified and labeled in accordance with the National Fenestration Rating Council (NFRC) Product Certification Program (PCP), as authorized by an independent certification and inspection agency licensed by the NFRC. Compliance shall be based on the Residential Model Size. Product samples used for U-factor determinations shall be production line units or representative of units as purchased by the consumer or contractor.

[g] Reference case glazing area limitation for use in thermal envelope component tradeoff calculations. Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values.

[h] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[i] Indoor air quality should be comparable to levels found in non-model conservation standards dwellings built in 1983. To ensure that indoor air quality comparable to 1983 practice is achieved, Bonneville's programs must include pollutant source control (including, but not limited to, combustion by-products, radon and formaldehyde), pollutant monitoring, and mechanical ventilation, that may, but need not, include heat recovery. An example of source control is a requirement that wood stoves and fireplaces be provided with an outside source of combustion air. At a minimum, mechanical ventilation shall have the capability of providing the outdoor air quantities specified in the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62-89, *Ventilation for Acceptable Indoor Air Quality*. Natural ventilation through operable exterior openings and infiltration shall not be considered acceptable substitutes for achieving the requirements specified in ASHRAE Standard 62-89.

[j] Energy Factor varies by tank capacity. Energy Factor = 0.996 - 0.00132 x rated volume

| Table F-2: Illustrative Paths for the Model Conservation Standard for New Electrically Heated Manufactured Homes[a] | | | |
|---|---|---|---|
| | **Climate Zone** | | |
| **Component** | **Zone 1** | **Zone 2** | **Zone 3** |
| **Ceilings** | | | |
| • Attic | R-38 (U-0.027) | R-38 (U-0.027) | R-49 (U-0.023) |
| • Vaults | R-30 (U-0.033) | R-38 (U-0.030) | R-38 (U-0.030) |
| **Walls** | | | |
| • Above Grade | R-21 Advanced (U-0.050) | R-21 Advanced (U-0.050) | R-21 Advanced (U-0.050) |
| **Floors** | | | |
| • Crawlspaces | R-33 (U-0.032) | R-33 (U-0.032) | R-33 (U-0.032) |
| Glazing[b] | R-3.3 (U-0.30) | R-3.3 (U-0.30) | R-3.3 (U-0.30) |
| Maximum Glazed Area (% floor area)[c] | 15 | 15 | 15 |
| Exterior Doors | R-5 (U-0.19) | R-5 (U-0.19) | R-5 (U-0.19) |
| Assumed Thermal Infiltration Rate[d] | 0.35 ach | 0.35 ach | 0.35 ach |
| Overall Conductive Heat Loss Rate (Uo) | 0.049 | 0.048 | 0.047 |
| Mechanical Ventilation[e] | See footnote e, below | | |
| Service Water Heater[f] | Energy Factor = 0.93 | | |

[a] R-values listed in this table are for the insulation only. U-factors listed in the table are for the full assembly of the respective component and are based on the methodology defined in the *Super Good Cents Heat Loss Reference for Manufactured Homes —*

[b] U-factors for glazing shall be determined, certified and labeled in accordance with the National Fenestration Rating Council (NFRC) Product Certification Program (PCP), as authorized by an independent certification and inspection agency licensed by the NFRC. Compliance shall be based on the Residential Model Size. Product samples used for U-factor determinations shall be production line units or representative of units as purchased by the consumer or contractor.

[c] Reference case glazing area limitation for use in thermal envelope component tradeoff calculations. Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values.

[d] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[e] Indoor air quality should be comparable to levels found in non-model conservation standards dwellings built in 1983. To ensure that indoor air quality comparable to 1983 practice is achieved, Bonneville's programs must include pollutant source control (including, but not limited to, combustion by-products, radon and formaldehyde), pollutant monitoring, and mechanical ventilation, that may, but need not, include heat recovery. An example of source control is a requirement that wood stoves and fireplaces be provided with an outside source of combustion air. At a minimum, mechanical ventilation shall have the capability of providing the outdoor air quantities specified in the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62-89, *Ventilation for Acceptable Indoor Air Quality*. Natural ventilation through operable exterior openings and infiltration shall not be considered acceptable substitutes for achieving the requirements specified in ASHRAE Standard 62-89.

[j] Energy Factor varies by tank capacity. Energy Factor = 0.996 - 0.00132 x rated volume

## The Model Conservation Standard for New Commercial Buildings

The American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. Standard 90.1 (ASHRAE Standard 90.1) is the reference standard in the United States for construction of new commercial buildings. ASHRAE Standard 90.1 is under continuous revision. The Council finds that measures required to meet the current version, ASHRAE Standard 90.1-2001 with addenda a through am, are commercially available, reliable and economically feasible for consumers without financial assistance from Bonneville. The Council also finds that the measures required to meet the ASHRAE Standard 90.1-2001 do not capture all regionally cost-effective savings.

Furthermore, the Council finds that commercial building energy standards adopted by the four states in the region contain many energy efficiency provisions that exceed ASHRAE Standard 90.1 provisions; produce power savings that are cost-effective for the region and are economically feasible for customers. Those state or locally adopted efficiency provisions that are superior to ASHRAE Standard 90.1 should be maintained. In addition, efforts should be made by code setting jurisdictions to adopt the most efficient provisions of ASHRAE Standard 90.1 or existing local codes so long as those provisions satisfy the conditions for model conservation standards set forth in the Regional Act.

Therefore, the model conservation standard for new commercial buildings is as follows: New commercial buildings and existing commercial buildings that undergo major remodels or renovations are to be constructed to capture savings equivalent to those achievable through constructing buildings to the better of 1) the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 90.1-2001 (I-P Version) -- Energy Standard for Buildings Except Low-Rise Residential Buildings (IESNA cosponsored; ANSI approved; Continuous Maintenance Standard), I-P Edition and addenda a through am or subsequent revision to ASHRAE Standard 90.1, or 2) the most efficient provisions of existing commercial building energy standards promulgated by the states of Idaho, Montana, Oregon and Washington so long as those provisions reflect geographic and climatic differences within the region, other appropriate considerations, and are designed to produce power savings that are cost-effective for the region and economically feasible for customers taking into account financial assistance made available from Bonneville.

As with the residential model conservation standard, flexibility is encouraged in designing paths to achieve the commercial model conservation standards. The Council will consult with the Administrator, States, and political subdivisions, customers of the Administrator, and the public to assist in determining which provisions of existing standards are the most efficient, and provide clear code language, are easily enforced and meet the conditions for model conservation standards set forth in the Regional Act.

## The Model Conservation Standard for Utility Conservation Programs for New Commercial Buildings

The model conservation standard for utility conservation programs for new commercial buildings is as follows: Utilities should implement programs that are designed to capture all regionally cost-effective electricity savings in new commercial buildings. Efforts to achieve and maintain a goal of 85 percent of regionally cost-effective savings in new commercial buildings should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness all costs, including utility administrative costs and financial assistance payments, should be taken into account.

There are several ways utilities can satisfy the model conservation standard for utility conservation programs for new commercial buildings. These are:

1. Support the adoption and/or continued enforcement of an energy code for new commercial buildings that captures all regionally cost-effective electricity savings.
2. Implement a conservation program that is designed to capture all regionally cost-effective electricity savings in new commercial buildings. Such programs may include, but are not limited to, state or local government or utility marketing programs, financial assistance, codes/utility service standards or fees that capture all the regionally cost-effective savings or combinations of these and/or other measures to encourage energy-efficient construction of new commercial buildings or other lost-opportunity conservation resources.

## The Model Conservation Standard for Buildings Converting to Electric Space Conditioning or Water Heating Systems

The model conservation standard for existing residential and commercial buildings converting to electric space conditioning or water heating systems is as follows: State or local governments or utilities should take actions through codes, service standards, user fees or alternative programs or a combination thereof to achieve electric power savings from such buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or electric water heating were upgraded to include all regionally cost-effective electric space conditioning and electric water heating conservation measures.

## The Model Conservation Standard for Conservation Programs not Covered by Other Model Conservation Standards

This model conservation standard applies to all conservation actions except those covered by the model conservation standard for new electrically heated residential buildings, the standard for utility conservation programs for new residential buildings, the standard for all new commercial buildings, the standard for utility conservation programs for new commercial buildings and the standard for electric space conditioning and electric water heating system conversions. This model conservation standard is as follows: All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system. In order to achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to capture all regionally cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-

opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use.

2. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in the commercial sector, measures can be installed at the time of renovation or remodel.
3. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.
4. Conservation acquisitions programs should be targeted at conservation opportunities that are not anticipated to be developed by consumers.
5. Conservation acquisition programs should be designed to ensure that regionally cost-effective levels of efficiency are economically feasible for the consumer.
6. Conservation acquisition programs should be designed so that their benefits are distributed equitably.
7. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acquisition of conservation measures that result in environmental degradation should be avoided or minimized.
8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

## SURCHARGE RECOMMENDATION

The Council does not recommend that the model conservation standards be subject to surcharge under Section 4(f) (2) of the Act.

The Council expects that Bonneville and the region's utilities will accomplish conservation resource development goals established in this Plan. If Council recommendations on the role of Bonneville are adopted, utility incentives to pursue all cost-effective conservation should improve. Fewer customers would be dependent on Bonneville for load growth and those that are would face wholesale prices that reflect the full marginal cost of meeting load growth. However, while these changes would lessen the rationale for a surcharge, the Council recognizes that they would not eliminate all barriers to utility development of programs to capture all cost-effective conservation.

The Council recognizes that while conservation represents the lowest life cycle cost option for meeting the region's electricity service needs, utilities face real barriers to pursuing its development aggressively. In particular, as a consequence of the West Coast Energy Crisis, many utilities have recently increased their rates significantly. Investments in conservation, like any other resource acquisition, will increase utility cost and place additional upward pressure on rates. Furthermore, it is uncertain when and to what extent Bonneville will implement the Council's recommended role in power supply and whether Bonneville will establish rates that result in all of its customers having at least some portion of their loads exposed to cost of new resources. Therefore, in the near term, Bonneville should structure its conservation programs to address the barriers faced by utilities.

The Council intends to continue to track regional progress toward the Plan's conservation goals and will review this recommendation, should accomplishment of these goals appear to be in jeopardy.

## Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act provides for Council recommendation of a 10-percent to 50-percent surcharge on Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards. The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth. As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge calculation for Bonneville's administrator to follow. Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

## Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards for utility residential and commercial conservation programs.

## Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.
2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.[4]

## Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

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[4] This calculation of the surcharge is designed to eliminate the possibility of surcharging a utility twice on the same load. In the calculation, the portion of a utility's exchange resource purchased from Bonneville and already surcharged under the power sales contract is subtracted from the exchange resources before establishing a surcharge on the exchange load.

# Model Conservation Standards

## COST-EFFECTIVENESS AND ECONOMIC FEASIBILITY OF THE MODEL CONSERVATION STANDARDS FOR NEW RESIDENTIAL BUILDINGS

This appendix provides an overview of the method and data used to evaluate the regional cost-effectiveness and consumer economic feasibility of the Council's Model Conservation Standards for New Residential Buildings. The first section describes the methodology, cost and savings assumptions used to establish the efficiency level that achieves all electricity savings that are cost-effective to the region's power system. The second section describes the methodology and assumptions used to determine whether the regionally cost-effective efficiency levels are economically feasible for new homebuyers in the region.

## REGIONAL COST EFFECTIVENESS

### Base Case Assumptions

Since the Council first promulgated its model conservation standards for new residential constructions in 1983 all of the states in the region have revised their energy codes. Consequently, many of the conservation measures included in the Council's original standards have now been incorporated into state regulations. In addition, some of the measures identified in prior Council Power Plan's as being regionally cost-effective when installed in new manufactured homes are now required by federal regulation.[1] This analysis assumes that the "base case" construction practices in the region comply with existing state codes and federal standards. However, since not all of the energy codes in the region are equally stringent this analysis uses the less restrictive measure permitted by code for each building component (e.g., walls, windows, doors, etc.). Table G-1 shows the levels of energy efficiency assumed for new site built and manufactured homes built to existing state codes and federal standards.

[1] The energy efficiency of new manufactured homes are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983) which also pre-empts state regulation of their construction.

**Table G-1: Base Case Efficiency Level Assumptions**

| Component | Site Built Homes | Manufactured Homes |
|---|---|---|
| Attic | R38 Standard Framing | R38 Intermediate Framing |
| Door | R5 | R5 |
| Floor | R25 | R22 |
| Infiltration | 0.35 Air changes per hour | 0.35 Air changes per hour |
| Joisted Vault | R30 | R19 |
| Slab-on-Grade (F-Value/linear foot of perimeter) | R10 | Not Applicable |
| Trussed Vault | R38 | R19 |
| Wall | R19 Standard Framing | R19 |
| Wall Below Grade (Interior) | R11 | Not Applicable |
| Slab-below-Grade (F-Value/lin.ft. perimeter) | R10 | Not Applicable |
| Window | Class 40 (U<0.40) | Class 50 (U<0.50) |

## Measure Cost Assumptions

The cost data for new site built homes used in the Council's analysis were obtained from a 1994 survey of new residential construction costs prepared for Bonneville.[2] These costs were converted to year 2000 dollars using the GDP Deflator from mid-1994 to mid-2000. Costs were obtained from builders, subcontractors and materials suppliers from across the region and include a 36 percent markup for overhead and profit. Table G-1 provides a summary of the incremental costs used in the staff analysis for site built homes.

Cost for new manufactured home energy efficiency improvements were obtained from regional manufacturers, insulation and window.[3] Table G-2 summarizes this same information for manufactured homes. These cost assume a manufacturer markup on material costs of 200 percent to cover labor and production cost and profit as well as and a retailer markup of 35 percent.

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[2] Frankel, Mark, Baylon, D. and M. Lubliner 1995. Residential Energy Conservation Evaluation: Cost-Effectiveness of Energy Conservation Measures in New Residential Construction in Washington State. Washington State Energy Office, Olympia, WA. and the Bonneville Power Administration, Portland, OR.

[3] Davis, Robert, D. Baylon and L. Palmiter, 1995 (draft report). *Impact Evaluation of the Manufactured Housing Acquisition Program (MAP).* Bonneville Power Administration, Portland, OR.

**Table G-2: Incremental Cost of New Site Built Residential Space Heating Conservation Measures**

| Conservation Measure | Incremental Installed Cost (2000$/sq.ft.) |
|---|---|
| Wall R19 Standard Framing | Base |
| Wall R19 Intermediate Framing | $(0.04) |
| Wall R21 Intermediate Framing | $0.15 |
| Wall R21 Advanced Framing | $0.15 |
| Wall R21 Standard Framing + R5 Foam | $0.84 |
| Wall R30 Stressed Skin Panel | $1.15 |
| Wall R38 Double Wall | $0.59 |
| Attic R38 Standard Framing | Base |
| Attic R49 Advanced Framing | $0.69 |
| Attic R60 Advanced Framing | $0.40 |
| Vault R30 (Joisted) | Base |
| Vault R38 (Joisted w/High Density Insulation) | $0.61 |
| Vault R50 Stressed Skin Panel | $2.11 |
| Vault R30 (Scissor Truss) | Base |
| Vault R38 (Scissor Truss) | $0.61 |
| Underfloor R25 | Base |
| Underfloor R30 | $0.24 |
| Underfloor R38 (Truss joist) | $0.40 |
| Window Class 40 (U<0.40) | Base |
| Window Class 35 (U<0.35) | $0.66 |
| Window Class 30 (U<0.30) | $3.46 |
| Window Class 25 (U<0.25) | $3.69 |
| Exterior Door R5 | Base |
| Slab-on-Grade R10 Perimeter, down 2 ft. | Base |
| Slab-on-Grade R10 Perimeter, down 4 ft. | $2.48 |
| Slab-on-Grade R10 Perimeter & Full Under Slab | $4.98 |
| Below-Grade Wall R11 Interior | Base |
| Below-Grade Wall R19 Interior | $0.30 |
| Below-Grade Wall R21 Interior | $0.15 |

**Table G-3: Incremental Cost of New Manufactured Home Residential Space Heating Conservation Measures**

| Conservation Measure | Incremental Installed Cost (2000$/sq.ft.) |
|---|---|
| Wall R11 Standard Framing | Base |
| Wall R19 Standard Framing | $0.54 |
| Wall R21 Standard Framing | $0.15 |
| Attic R19 | Base |
| Attic R25 | $0.11 |
| Attic R30 | $0.09 |
| Attic R38 | $0.13 |
| Attic R49 | $0.19 |
| Vault R19 | Base |
| Vault R25 | $0.11 |
| Vault R30 | $0.09 |
| Vault R38 | $0.13 |
| Underfloor R22 | Base |
| Underfloor R33 | $0.15 |
| Underfloor R44 | $0.15 |
| Window Class 50 (U<0.50) | Base |
| Window Class 40 (U<0.40) | $1.91 |
| Window Class 35 (U<0.35) | $1.00 |
| Window Class 30 (U<0.30) | $1.00 |
| Exterior Door R2.5 | Base |
| Exterior Door R5 | $4.54 |

## Energy Use Assumptions

The Council used an engineering simulation model, SUNDAY©, which has been calibrated to end-use metered space heating for electrically heated homes built across the region.[4] Savings were computed for each measure based on the "economic" optimum order of application. This was done by first computing the change in heat loss rate (UA) that resulted from the application of each measure. The incremental cost of installing each measure was then divided by this "delta UA" to establish a measure's benefit-to-cost ratio (i.e., dollars/delta UA). The SUNDAY© simulation model was then used to estimate the space heating energy savings that would result from the applying all measures starting with those that had the largest benefit-to-cost ratios. Savings were estimated for three typical site built single-family homes and three typical manufactured homes. Table G-4 provides a summary of the component areas for each of these six homes.

[4] Palmiter, L., I. Brown and M. Kennedy 1988. *SUNDAY© Calibration*. Bonneville Power Administration, Portland, OR.

**Table G-4: Prototypical Home Component Dimensions**

| | Site Built Homes | | | Manufactured Homes | | |
|---|---|---|---|---|---|---|
| Component | 1,344 sq.ft. | 2,200 sq.ft. | 2,283 sq.ft. | 924 sq.ft. | 1,568 sq.ft. | 2,352 sq.ft. |
| Attic | 960 | 802 | 719 | 400 | 908 | 1,092 |
| Door | 38 | 55 | 89 | 38 | 38 | 58 |
| Floor | 1,344 | 1,721 | 104 | 924 | 1,568 | 2,352 |
| Volume | 10,752 | 17,600 | 18,264 | 7,577 | 12,858 | 19,286 |
| Joisted Vault | | | 479 | | | 479 |
| Slab-on-Grade (F-Value/lin.ft.perimeter) | | | 140 | | | 140 |
| Trussed Vault | 405 | 684 | | 524 | 660 | 1,558 |
| Wall | 1,231 | 2,122 | 1,817 | 1,048 | 1,026 | 1,059 |
| Wall below Grade (Int.) | | | 560 | | | 560 |
| Slab-below-Grade (F-Value/lin.ft.perimeter) | | | 140 | | | 140 |
| Window | 176 | 366 | 210 | 116 | 196 | 353 |
| Envelop Area | 4,154 | 5,750 | 4,258 | 3,050 | 4,396 | 7,791 |

Five locations, Seattle, Portland, Boise, Spokane and Missoula were selected to represent the range of climates found across the region. The savings produced by each measure across all five locations were then weighted together based on the share of new housing built in each location to form the three climate zones used by the Council. Table G-5 shows the weights used.

**Table G-5: Location Weights Used to Establish Northwest Heating Zones**

| Location | Portland | Seattle | Boise | Spokane | Missoula |
|---|---|---|---|---|---|
| Heating Zone 1 | 25% | 53% | 22% | 0% | 0% |
| Heating Zone 2 | 0% | 0% | 15% | 85% | 0% |
| Heating Zone 3 | 0% | 0% | 0% | 0% | 100% |

In order to determine whether a measure is regionally cost-effective the Council then compared to cost of installing each measure with the value of the energy savings it produced over its lifetime. The value of all conservation savings vary by time of day and season of the year based on the market prices for electricity across the West and the impact of the savings on the need to expand the region's transmission and distribution system.

Tables F-6 through F-8 show the results of the cost-effectiveness analysis for each heating climate zone for site built homes and Tables F-9 through F-11 show the results of the cost-effectiveness analysis for new manufactured homes. All measures with a benefit/cost (B/C) ratio of 1.0 or larger are considered regionally cost-effective.

**Table G-6: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 1**

| **1344 sq.ft.** | | | | **2200 sq.ft.** | | | | **2283 sq.ft** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Wall R21 ADV | $182 | **565** | **2.77** | Wall R21 ADV | $313 | **975** | **2.80** | Wall R21 ADV | $268 | **894** | **3.05** |
| Window CL35 | $117 | **344** | **2.61** | Window CL35 | $243 | **710** | **2.61** | Window CL35 | $133 | **422** | **2.90** |
| Floor R30 STD | $318 | **662** | **1.83** | Floor R30 STD | $407 | **839** | **1.85** | Floor R30 STD | $25 | **56** | **2.07** |
| Floor R38 STD w/12” Truss | $536 | **382** | **0.62** | Floor R38 STD w/12” Truss | $686 | **484** | **0.63** | BG Wall R19 | $165 | **294** | **1.62** |
| Attic R49 ADVrh | $666 | **426** | **0.56** | Attic R49 ADVrh | $557 | **352** | **0.57** | Slab R10-4 ft. | $347 | **375** | **0.99** |
| Window CL30 | $608 | **335** | **0.48** | Window CL30 | $1,265 | **689** | **0.48** | Slab R10-Full | $697 | **747** | **0.98** |
| Window CL25 | $650 | **332** | **0.44** | Window CL25 | $1,351 | **688** | **0.45** | Floor R38 STD w/12” Truss | $41 | **32** | **0.71** |
| Vault R38 HD | $245 | **111** | **0.39** | Vault R38 HD | $414 | **187** | **0.40** | Attic R49 ADVrh | $832 | **582** | **0.64** |
| Wall R21 STD+R5 | $1,036 | **381** | **0.32** | Wall R21 STD+R5 | $1,786 | **658** | **0.33** | Window CL30 | $691 | **418** | **0.55** |
| Wall 8” SS Panel | $1,418 | **421** | **0.26** | Wall 8” SS Panel | $2,444 | **725** | **0.26** | Window CL25 | $738 | **420** | **0.52** |
| Attic R60 ADVrh | $383 | **107** | **0.24** | Attic R60 ADVrh | $320 | **90** | **0.25** | Wall R21 STD+R5 | $1,529 | **635** | **0.38** |
| Wall R33 DBL | $727 | **46** | **0.05** | Wall R33 DBL | $1,253 | **79** | **0.06** | BG Wall R21 | $83 | **31** | **0.34** |
| Vault 10” SS Panel | $855 | **15** | **0.01** | Vault 10” SS Panel | $1,444 | **26** | **0.02** | Wall 8” SS Panel | $2,093 | **711** | **0.31** |

**Table G-7: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 2**

| 1344 sq. ft | | | | 2200 sq. ft | | | | 2283 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Wall R21 ADV | $182 | **550** | **3.66** | Wall R21 ADV | $313 | **948** | **3.66** | Wall R21 ADV | $268 | **872** | **3.93** |
| Window CL35 | $117 | **335** | **3.46** | Window CL35 | $243 | **690** | **3.43** | Window CL35 | $133 | **411** | **3.74** |
| Floor R30 STD | $318 | **644** | **2.45** | Floor R30 STD | $407 | **816** | **2.42** | Floor R30 STD | $25 | **54** | **2.68** |
| Floor R38 STD w/12” Truss | $536 | **371** | **0.84** | Floor R38 STD w/12” Truss | $686 | **471** | **0.83** | BG Wall R19 | $165 | **287** | **2.10** |
| Attic R49 ADVrh | $666 | **414** | **0.75** | Attic R49 ADVrh | $557 | **342** | **0.74** | Slab R10-4 ft. | $347 | **366** | **1.27** |
| Window CL30 | $608 | **325** | **0.65** | Window CL30 | $1,265 | **669** | **0.64** | Slab R10-Full | $697 | **729** | **1.26** |
| Window CL25 | $650 | **322** | **0.60** | Window CL25 | $1,351 | **668** | **0.60** | Floor R38 STD w/12” Truss | $41 | **31** | **0.92** |
| Vault R38 HD | $245 | **108** | **0.53** | Vault R38 HD | $414 | **182** | **0.53** | Attic R49 ADVrh | $832 | **569** | **0.83** |
| Wall R21 STD+R5 | $1,036 | **370** | **0.43** | Wall R21 STD+R5 | $1,786 | **639** | **0.43** | Window CL30 | $691 | **409** | **0.71** |
| Wall 8” SS Panel | $1,418 | **409** | **0.35** | Wall 8” SS Panel | $2,444 | **704** | **0.35** | Window CL25 | $738 | **410** | **0.67** |
| Attic R60 ADVrh | $383 | **104** | **0.33** | Attic R60 ADVrh | $320 | **87** | **0.33** | Wall R21 STD+R5 | $1,529 | **621** | **0.49** |
| Wall R33 DBL | $727 | **44** | **0.07** | Wall R33 DBL | $1,253 | **77** | **0.07** | BG Wall R21 | $83 | **30** | **0.44** |
| Vault 10” SS Panel | $855 | **15** | **0.02** | Vault 10” SS Panel | $1,444 | **25** | **0.02** | Wall 8” SS Panel | $2,093 | **694** | **0.40** |

**Table G-8: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 3**

| 1344 sq. ft | | | | 2200 sq. ft | | | | 2283 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Wall R21 ADV | $182 | **655** | **4.35** | Wall R21 ADV | $237 | **583** | **3.10** | Wall R21 ADV | $356 | **910** | **3.23** |
| Window CL35 | $117 | **399** | **4.13** | Window CL35 | $98 | **223** | **2.86** | Window CL35 | $118 | **279** | **2.98** |
| Floor R30 STD | $318 | **766** | **2.92** | Floor R30 STD | $71 | **159** | **2.82** | Floor R30 STD | $168 | **394** | **2.95** |
| Floor R38 STD w/12” Truss | $536 | **443** | **1.00** | Floor R38 STD w/12” Truss | $78 | **137** | **2.20** | BG Wall R19 | $94 | **171** | **2.28** |
| Attic R49 ADVrh | $666 | **493** | **0.89** | Attic R49 ADVrh | $57 | **100** | **2.20** | Slab R10-4 ft. | $135 | **244** | **2.28** |
| Window CL30 | $608 | **386** | **0.77** | Window CL30 | $374 | **533** | **1.79** | Slab R10-Full | $674 | **1,004** | **1.88** |
| Window CL25 | $650 | **384** | **0.71** | Window CL25 | $196 | **273** | **1.76** | Floor R38 STD w/12” Truss | $353 | **517** | **1.85** |
| Vault R38 HD | $245 | **129** | **0.63** | Vault R38 HD | $196 | **265** | **1.70** | Attic R49 ADVrh | $353 | **501** | **1.79** |
| Wall R21 STD+R5 | $1,036 | **444** | **0.52** | Wall R21 STD+R5 | $152 | **176** | **1.46** | Window CL30 | $157 | **190** | **1.52** |
| Wall 8” SS Panel | $1,418 | **493** | **0.42** | Wall 8” SS Panel | $118 | **129** | **1.38** | Window CL25 | $142 | **163** | **1.46** |
| Attic R60 ADVrh | $383 | **126** | **0.40** | Attic R60 ADVrh | $86 | **56** | **0.82** | Wall R21 STD+R5 | $202 | **138** | **0.86** |
| Wall R33 DBL | $727 | **54** | **0.09** | Wall R33 DBL | $177 | **102** | **0.73** | BG Wall R21 | $212 | **129** | **0.77** |
| Vault 10” SS Panel | $855 | **18** | **0.02** | Vault 10” SS Panel | $237 | **88** | **0.47** | Wall 8” SS Panel | $356 | **139** | **0.49** |

**Table G-9: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 1**

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Floor R33 | $140 | **328** | **2.96** | Floor R33 | $237 | **583** | **3.10** | Floor R33 | $356 | **910** | **3.23** |
| Attic R25 | $43 | **94** | **2.75** | Attic R25 | $98 | **223** | **2.86** | Attic R25 | $118 | **279** | **2.98** |
| Vault R25 | $57 | **122** | **2.72** | Vault R25 | $71 | **159** | **2.82** | Vault R25 | $168 | **394** | **2.95** |
| Attic R30 | $35 | **57** | **2.08** | Attic R30 | $78 | **137** | **2.20** | Attic R30 | $94 | **171** | **2.28** |
| Vault R30 | $45 | **75** | **2.08** | Vault R30 | $57 | **100** | **2.20** | Vault R30 | $135 | **244** | **2.28** |
| Window CL40 | $222 | **304** | **1.73** | Window CL40 | $374 | **533** | **1.79** | Window CL40 | $674 | **1,004** | **1.88** |
| Window CL35 | $116 | **155** | **1.68** | Window CL35 | $196 | **273** | **1.76** | Window CL35 | $353 | **517** | **1.85** |
| Window CL30 | $116 | **152** | **1.65** | Window CL30 | $196 | **265** | **1.70** | Window CL30 | $353 | **501** | **1.79** |
| Wall R21 ADV | $156 | **172** | **1.39** | Wall R21 ADV | $152 | **176** | **1.46** | Wall R21 ADV | $157 | **190** | **1.52** |
| Attic R38 | $52 | **54** | **1.31** | Attic R38 | $118 | **129** | **1.38** | Attic R38 | $142 | **163** | **1.46** |
| Vault R38 | $68 | **42** | **0.79** | Vault R38 | $86 | **56** | **0.82** | Vault R38 | $202 | **138** | **0.86** |
| Attic R49 | $78 | **43** | **0.70** | Attic R49 | $177 | **102** | **0.73** | Attic R49 | $212 | **129** | **0.77** |
| Floor R44 | $140 | **50** | **0.45** | Floor R44 | $237 | **88** | **0.47** | Floor R44 | $356 | **139** | **0.49** |

**Table G-10: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 2**

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Floor R33 | $140 | **441** | **3.98** | Floor R33 | $237 | **764** | **4.06** | Floor R33 | $356 | **1,175** | **4.16** |
| Attic R25 | $43 | **127** | **3.70** | Attic R25 | $98 | **293** | **3.76** | Attic R25 | $118 | **360** | **3.85** |
| Vault R25 | $57 | **165** | **3.68** | Vault R25 | $71 | **211** | **3.73** | Vault R25 | $168 | **512** | **3.84** |
| Attic R30 | $35 | **78** | **2.84** | Attic R30 | $78 | **181** | **2.91** | Attic R30 | $94 | **224** | **2.99** |
| Vault R30 | $45 | **102** | **2.84** | Vault R30 | $57 | **132** | **2.91** | Vault R30 | $135 | **319** | **2.98** |
| Window CL40 | $222 | **414** | **2.35** | Window CL40 | $374 | **711** | **2.39** | Window CL40 | $674 | **1,320** | **2.47** |
| Window CL35 | $116 | **212** | **2.30** | Window CL35 | $196 | **367** | **2.36** | Window CL35 | $353 | **683** | **2.44** |
| Window CL30 | $116 | **208** | **2.26** | Window CL30 | $196 | **356** | **2.29** | Window CL30 | $353 | **664** | **2.37** |
| Wall R21 ADV | $156 | **234** | **1.90** | Wall R21 ADV | $152 | **237** | **1.96** | Wall R21 ADV | $157 | **253** | **2.03** |
| Attic R38 | $52 | **74** | **1.79** | Attic R38 | $118 | **174** | **1.86** | Attic R38 | $142 | **217** | **1.93** |
| Vault R38 | $68 | **58** | **1.07** | Vault R38 | $86 | **75** | **1.10** | Vault R38 | $202 | **185** | **1.15** |
| Attic R49 | $78 | **59** | **0.95** | Attic R49 | $177 | **137** | **0.98** | Attic R49 | $212 | **173** | **1.03** |
| Floor R44 | $140 | **68** | **0.61** | Floor R44 | $237 | **118** | **0.63** | Floor R44 | $356 | **186** | **0.66** |

**Table G-11: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 3**

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** | **Measure** | **Installed Cost** | **Savings (kWh/yr)** | **B/C Ratio** |
| Floor R33 | $140 | **527** | **4.75** | Floor R33 | $237 | **914** | **4.86** | Floor R33 | $356 | **1,392** | **4.93** |
| Attic R25 | $43 | **152** | **4.42** | Attic R25 | $98 | **351** | **4.51** | Attic R25 | $118 | **428** | **4.57** |
| Vault R25 | $57 | **197** | **4.39** | Vault R25 | $71 | **254** | **4.48** | Vault R25 | $168 | **609** | **4.56** |
| Attic R30 | $35 | **93** | **3.39** | Attic R30 | $78 | **218** | **3.50** | Attic R30 | $94 | **265** | **3.54** |
| Vault R30 | $45 | **122** | **3.39** | Vault R30 | $57 | **159** | **3.50** | Vault R30 | $135 | **378** | **3.54** |
| Window CL40 | $222 | **495** | **2.82** | Window CL40 | $374 | **858** | **2.89** | Window CL40 | $674 | **1,566** | **2.93** |
| Window CL35 | $116 | **254** | **2.76** | Window CL35 | $196 | **441** | **2.84** | Window CL35 | $353 | **806** | **2.88** |
| Window CL30 | $116 | **249** | **2.70** | Window CL30 | $196 | **428** | **2.75** | Window CL30 | $353 | **783** | **2.80** |
| Wall R21 ADV | $156 | **283** | **2.29** | Wall R21 ADV | $152 | **284** | **2.35** | Wall R21 ADV | $157 | **298** | **2.39** |
| Attic R38 | $52 | **89** | **2.16** | Attic R38 | $118 | **209** | **2.24** | Attic R38 | $142 | **256** | **2.28** |
| Vault R38 | $68 | **70** | **1.30** | Vault R38 | $86 | **90** | **1.33** | Vault R38 | $202 | **218** | **1.36** |
| Attic R49 | $78 | **71** | **1.15** | Attic R49 | $177 | **166** | **1.18** | Attic R49 | $212 | **204** | **1.21** |
| Floor R44 | $140 | **82** | **0.74** | Floor R44 | $237 | **143** | **0.76** | Floor R44 | $356 | **219** | **0.78** |

The Council's Model Conservation Standards are "performance based" and not prescriptive standards. That is, many different combinations of energy efficiency measures can be used to meet the overall performance levels called for in the standards. In order to translate the regional cost-effectiveness results into "model standards" the Council calculates the total annual space heating use of a "reference building" that meets the Council's standards so that its efficiency can be compared to the same building built with some other combination of measures. Table G-12 shows the maximum annual space heating use permitted under the draft fifth Plan's model standards "reference" case requirements for site built and manufactured homes for each of the region's three heating climate zones. These "performance budgets" incorporate all of the conservation measures shown in Tables F-6 through F-11 that have a benefit-to-cost ratio of 1.0 or higher on a total resource cost basis.

**Table G-12: Draft Fifth Plan Model Conservation Standards Annual Space Heating Budgets**[5]

| | Site Built Homes (kWh/sq.ft./yr) | Manufactured Homes (kWh/sq.ft/yr) |
|---|---|---|
| Heating Zone 1 | 3.3 | 2.6 |
| Heating Zone 2 | 4.8 | 3.9 |
| Heating Zone 3 | 5.8 | 4.8 |

The Council compared the annual space heating performance requirements in Table G-12 for site built homes with the requirements of state energy codes in the region. It also compared the annual space heating performance requirements in Table G-12 for manufactured homes with the requirements of regional Super Good Cents® manufactured home program specifications and current construction practices for non-Super Good Cents® manufactured homes. This comparison, shown in Table G-13, revealed that none of the region's energy codes or the Super Good Cents® program specifications for manufactured homes met the Model Conservation Standards goal of capturing all regionally cost-effective electricity savings. It therefore appears that further strengthening of these codes and program specifications is required. The following section addresses the question of whether these higher levels of efficiency would be economically feasible for consumers.

**Table G-13: Estimated Annual Space Heating Use for New Site Built Homes Complying with State Energy Codes and Manufactured Homes Built to Current Practice and Super Good Cents®**

| | Site Built Space Heating Use (kWh/sq.ft./yr | | | | Manufactured Home Space Heating Use (kWh/sq.ft./yr. | |
|---|---|---|---|---|---|---|
| | Idaho | Montana | Oregon | Washington | Current Practice | Super Good Cents® |
| Heating Zone 1 | 5.3 | NA | 3.5 | 3.6 | 4.3 | 3.0 |
| Heating Zone 2 | 7.6 | NA | 5.3 | 4.7 | 6.2 | 4.6 |
| Heating Zone 3 | NA | 6.8 | NA | NA | 7.7 | 5.8 |

5 Annual space heating use for a typical 2100 sq.ft. site built home and 1730 sq.ft. manufactured home. Both homes are assumed to have a zonal electric resistance heating system.

## Consumer Economic Feasibility

The Act requires that the Council's Model Conservation Standards be "economically feasible for consumers" taking into account any financial assistance made available through Bonneville and the region's utilities. In order to determine whether the performance standards set forth in Table G-12 met this test the Council developed a methodology that allowed it to compare the life cycle cost of home ownership, including energy costs, of typical homes with increasing levels of energy efficiency built into them. This section describes this methodology and results of this analysis.

The life cycle cost of home ownership is determined by many variables, such as the mortgage rate, down payment amount, the marginal state and federal income tax rates of the homebuyer, retail electric rates, etc. The value of some of these variables, such as property and state income tax rates are known, but differ across state or utility service areas or differ by income level. For example, homebuyers in Washington State pay no state income tax, while those in Oregon pay upwards of 9 percent of their income in state taxes. Since home mortgage interest payments are deductible, Oregon homebuyers have a lower "net" interest rate than do Washington buyers. The value of other variables, such as mortgage rates and the fraction of a home's price that the buyer pays as a down payment are a function of income, credit worthiness, market conditions and other factors. Consequently, it is an extreme oversimplification to attempt to represent the economic feasibility of higher levels of efficiency using the "average" of all of these variables as input assumptions.

In order to better reflect the range of conditions individual new homebuyers might face the Council developed a model that tested over a 1,000 different combinations of major variables that determine a specific consumer's life cycle cost of home ownership for each heating climate zone. Table G-14 lists these variables and the data sources used to derive the actual distribution of values used.

**Table G-14: Data Sources and Variables Used in Life Cycle Cost Analysis**

| Variable | Data Source |
|---|---|
| Average New Home Price | Federal Housing Finance Board |
| Mortgage Interest Rates | Federal Housing Finance Board & Mortgage Bankers Association |
| Down payment | Federal Housing Finance Board |
| Private Mortgage Insurance Rates | Mortgage Bankers Association |
| Retail Electric Rates | Energy Information Administration |
| Retail Gas Rates | ID, MT, OR & WA Utility Regulatory Commissions |
| Retail Electric and Gas Price Escalation Rates | Council Forecast |
| Federal Income Tax Rates | Internal Revenue Service |
| State Income and Property Tax Rates | ID, MT, OR & WA State Departments of Revenue |
| Adjusted Gross Incomes | Internal Revenue Service |
| Home owners insurance | Online estimates from Realtor.com |

A "Monte Carlo" simulation model add-on to Microsoft Excel called Crystal Ball® was used to select specific values for each of these variables from the distribution of each variable. Each combination of values was then to use to compute the present value of a 30-year (360 month) stream of mortgage principal and interest payments, insurance premiums, property taxes and energy cost for a new site built or manufactured home built to increasing levels of thermal efficiency. Figures F-1 through F-10 show the distributions used for each of the major input assumptions to the life cycle cost analysis.

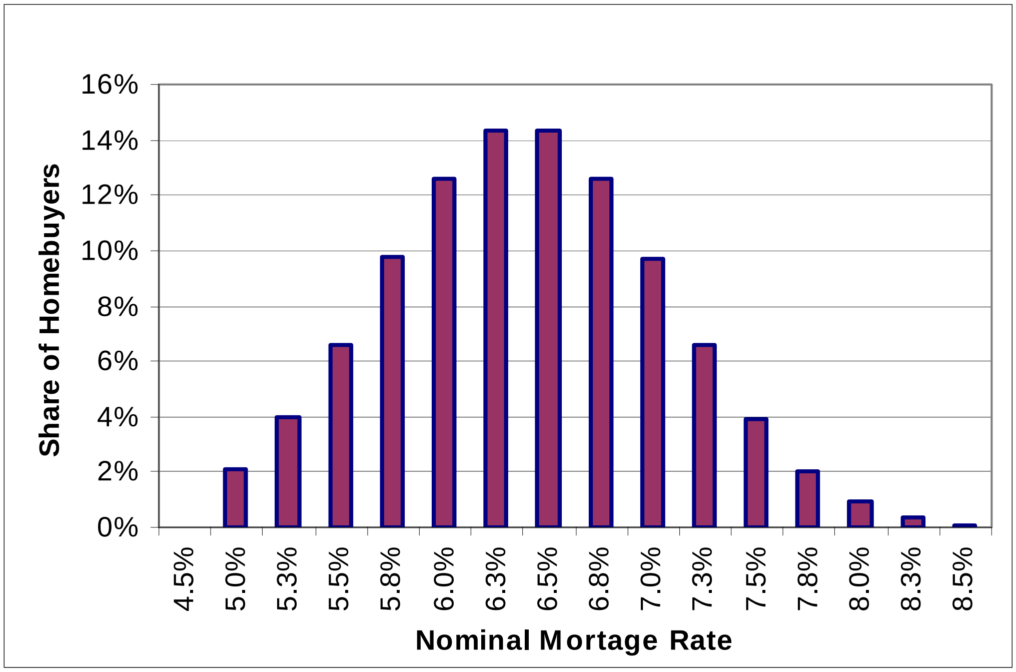


**Figure G-1: Nominal Mortgage Rates - All Climate Zones for Single Family Homes**

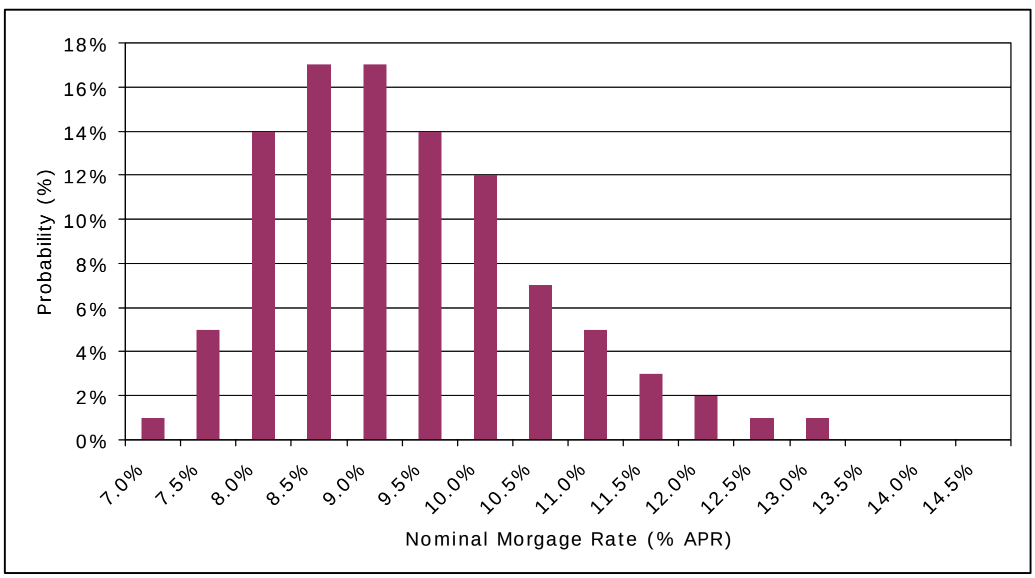


**Figure G-2: Nominal Mortgage Rates - All Climate Zones for Manufactured Homes**

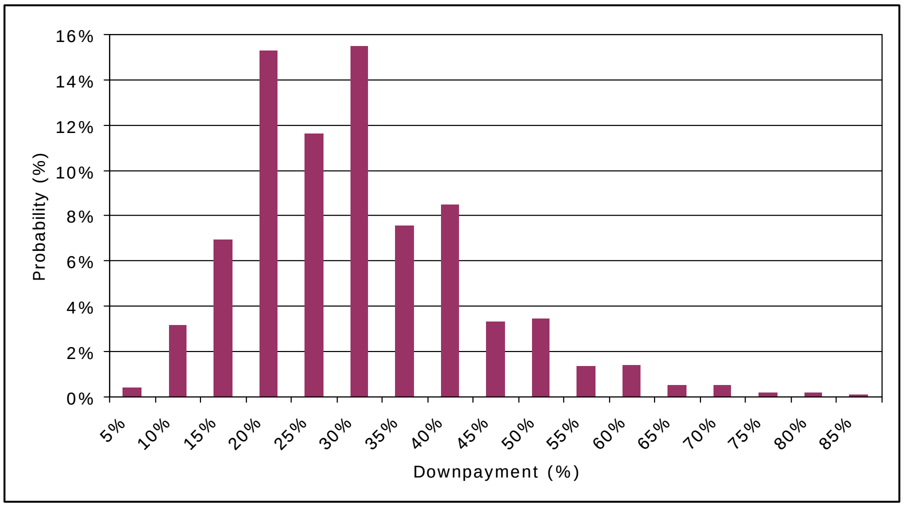


**Figure G-3: Down payment Fraction for Single Family and Manufactured Homes- All Climate Zones**

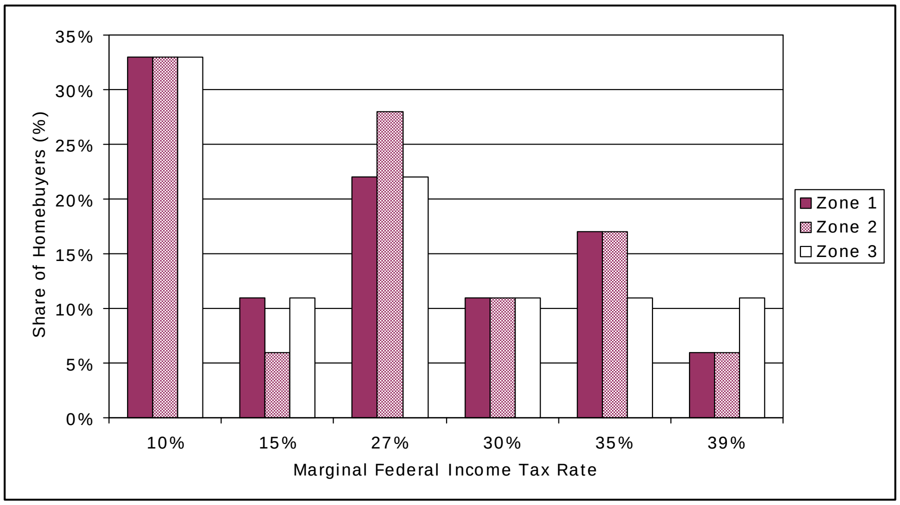


**Figure G-4: Marginal Federal Income Tax Rates for Single Family and Manufactured Homes by Climate Zone**

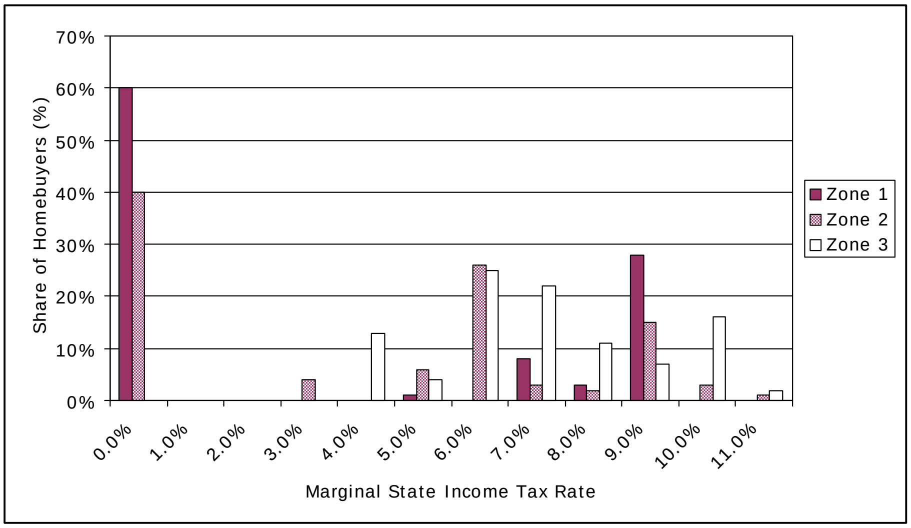


**Figure G-5: Marginal State Income Tax Rates for Single Family and Manufactured Homes by Climate Zone**

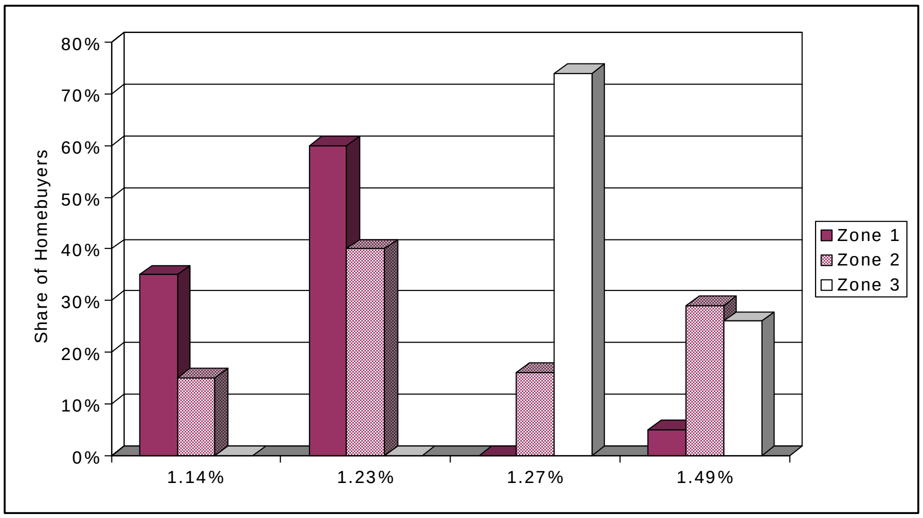


**Figure G-6: Property Tax Rates by Climate Zone**

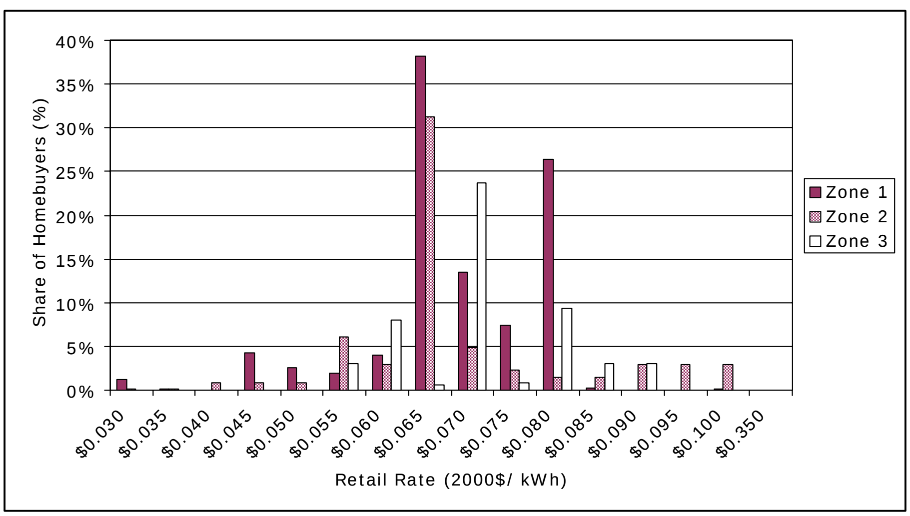


**Figure G-7: Base Year Retail Electric Rates by Climate Zone**

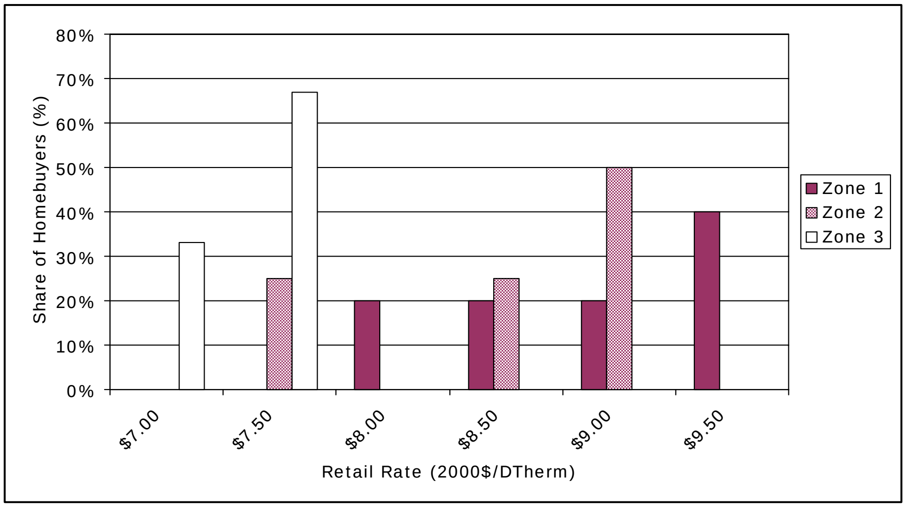


**Figure G-8: Base Year Retail Natural Gas Rates by Climate Zone**

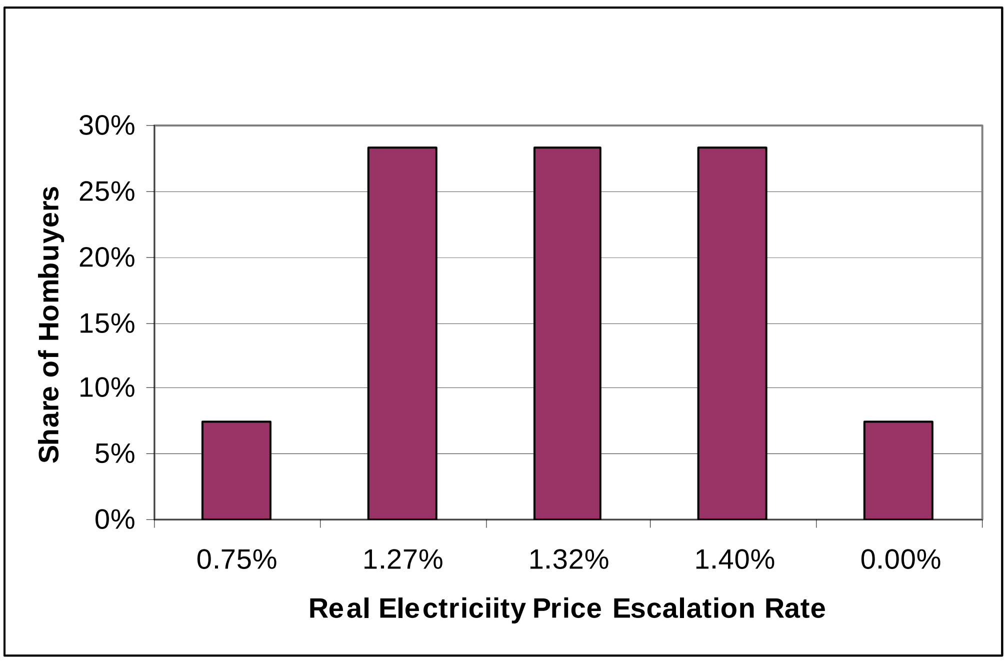


**Figure G-9: Real Escalation Rates for Electricity Prices - All Climate Zones**

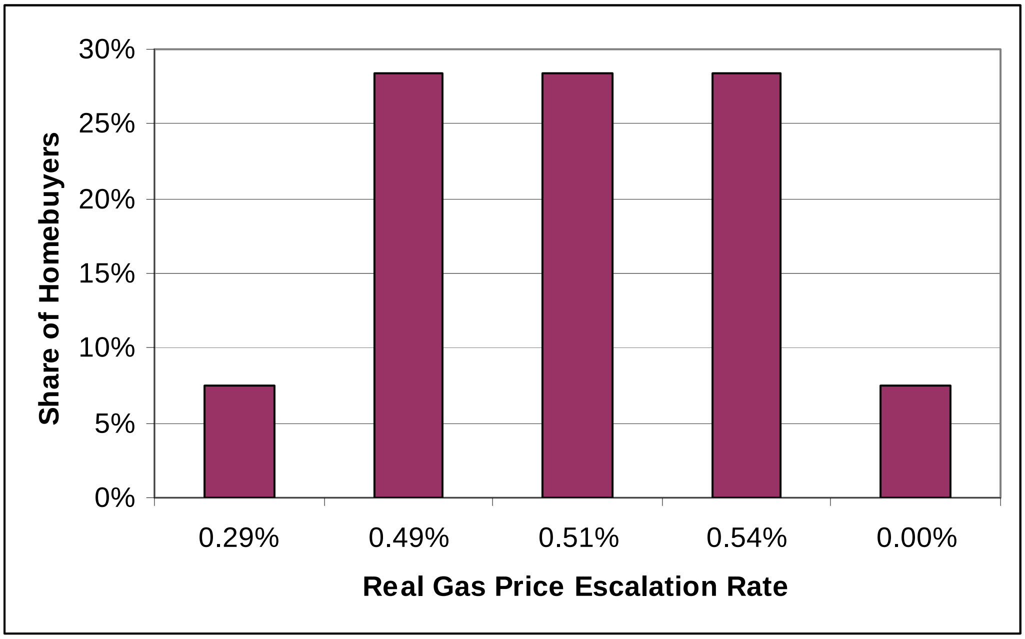


**Figure G-10: Real Escalation Rates for Natural Gas Prices - All Climate Zones**

The incremental costs of conservation measures described in the prior section on regional cost-effectiveness were used in these calculations. Annual space heating energy use was computed for four heating system types using the system efficiency assumptions shown in Table G-14. The system efficiency assumptions for electric and gas forced-air furnaces and heat pumps assume that the home has all or most of its ductwork outside the heated space.

**Table G-15: Overall Heating System Efficiency Assumptions by System Type and Climate Zone[6]**

| Climate Zone | Zonal Electric | Electric Forced-Air Furnace | Air Source Heat Pump | Gas Forced-Air Furnace |
|---|---|---|---|---|
| Zone 1 | 100% | 78% | 155% | 61% |
| Zone 2 | 100% | 77% | 124% | 60% |
| Zone 3 | 100% | 77% | 114% | 60% |

The simulation model used the same 1,000 combinations of input assumptions for each level of energy efficiency tested. As a result, the Council could compare the distribution of 1,000 different net present value results for a home built to incrementally higher levels of efficiency, rather than just single cases. This allowed the Council to consider how "robust" a conclusion one might draw regarding the economic feasibility of each measure.

Figure G-11 illustrates a typical distribution of net present value results for one measure. In the upper left corner of the graph indicates the number ("2000 Trials") of different combinations of inputs tested in the analysis. The graph plots the net present value of a measures costs and savings over the term of the mortgage on the horizontal (x) axis. The "probability" of obtaining a given net present values is plotted on the vertical (y) axis. The percent of the cases tested that result in a particular net present value is shown on the left vertical axis and the number of cases

[6] Overall system efficiency includes the impact of duct system losses, combustion and cycling losses and for heat pumps losses due to defrost and the use of controls that energize back up electric resistance heating during "warm-up."

out of the total number tested is shown on the right vertical axis. The mean (average) and median net present values of all input combinations tested are shown as vertical lines near the center of the distribution.

Although the mean values can be considered the “expected” net present value it is also important to consider the entire distribution of results to determine the share of consumers who would be harmed or benefited. This is particularly important of the results are skewed by a specific combination of input assumptions (e.g., low initial electric rates combined with low real escalating rates and high mortgage rates). Figure G-12 displays the cumulative distribution of net present value across the range of possible combinations of inputs. The primary value of displaying the outcomes in this fashion is that it shows the both the fraction of consumers who may be benefited or harmed if required to invest in incremental improvements in efficiency and it also shows the magnitude of the benefit or harm. For example, Figure G-12 shows that approximately 90 percent of the combinations tested resulted in net present values. Moreover 75 percent of the combination of input assumptions produced net present values above $500 while less than 5 percent of the produced negative net present values, none of which were below $1,000.

Tables F-16 through F-18 show the average or “expected” net present value for each measure and heating system type by climate zone for site built homes. Tables F-19 through -21 show this information for manufactured homes.

The Council reviewed the net present value results for each measure. Measures were analyzed incrementally and in order of their cost-effectiveness. The package of measures that produced the highest average net present value (lowest life cycle cost) was considered by the Council to be “economically feasible” for consumers. The Council believes this is a conservation interpretation of the Act’s requirements, since any package of measures that results in a higher net present value than current codes or standards leaves the consumer “better off” than they are today. However, the package of measures that produces the highest net present value leaves results in the “best” economic choice for the consumer.

Based on its review of these results shown in Tables F-15 through F-20 the Council concluded that the level of energy efficiency that is regionally cost-effective shown in Table G-12 are also economically feasible for consumers. Table G-21 compares the annual space heating performance of typical site-built home and manufactured homes built to three different levels of energy efficiency. One is built to current codes/practice, the second with all regionally cost effective measures (i.e., “the MCS”) and the third with those measures that maximize the net present value of energy efficiency to the homeowner (i.e., “Economically Feasible”).

It is important to note that Table G-21 shows that the level of energy efficiency that is economically feasible for consumers is equal to or higher than that which would be cost-effective for the regional power system. Since this is the first time the Council has observed this result, some explanation is in order. There are two primary reasons that consumers in the Northwest would find it more economical to invest in the energy efficiency of their new site built or manufactured home than the regional power system. The first is that as a result of recent increases in power rates retail rates for electricity are generally above wholesale market prices.

Second, new homebuyers can frequently finance their homes at lower interest rates than utilities can borrow money to fund conservation programs.

The complete distribution of net present value results for each measure by heating system type for site built homes are shown in Figures F-13 through F-58 for climate zone 1, Figures F-63 through F-108 for climate zone 2 and Figures F-113 through F-158 for climate zone 3. The "expected value" average net present value results for each measure and heating system type are shown in figures F-59 through F-62 for climate zone 1, Figures F-109 through F-112 for climate zone 2 and Figures F-159 through F-162 for climate zone 3. The complete net present value results for each measure for manufactured homes are shown in Figures F-163 through F-175 for climate zone 1, Figures F-177 through F-189 for climate zone 2 and Figures F-191 through F-203 for climate zone 3. The "expected value" average net present value results for each measure are shown in Figure G-176 for climate zone 1, Figure G-190 for climate zone 2 and Figure G-204 for climate zone 3. Tables F-19 through -20 average "expected value" net present value for each measure by climate zone for manufactured homes.

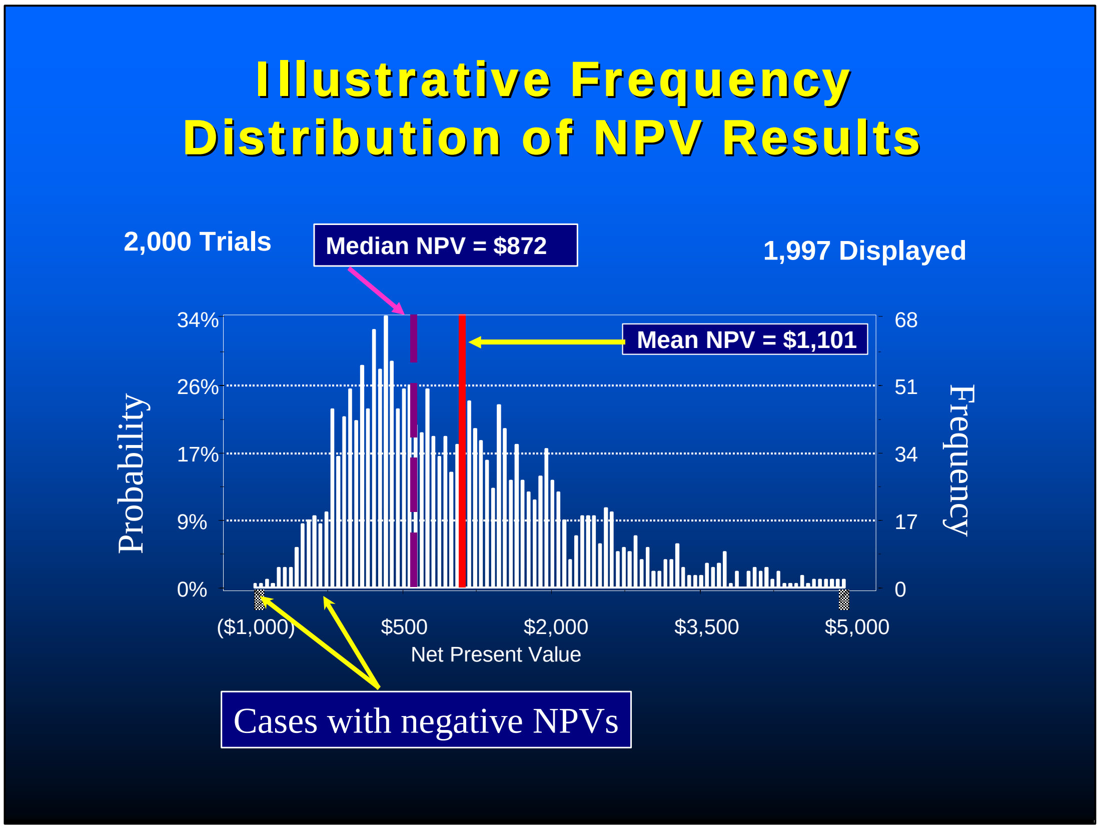


**Figure G-11: Illustrative Distribution of Net Present Value Results**

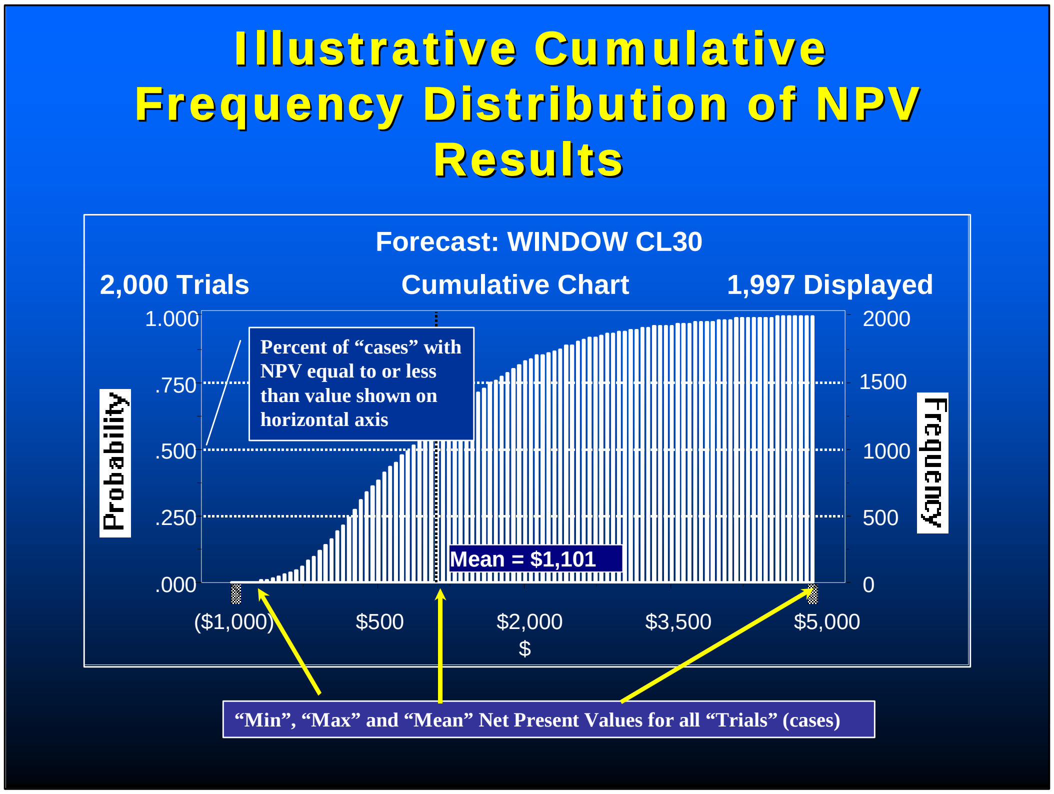


**Figure G-12: Illustrative Cumulative Distribution of Net Present Value Results**

## Mean Net Present Value for Zone 1 (1000 Cases)

| Measure | HP | Electric FAF | Gas FAF | Zonal |
|---|---|---|---|---|
| R21 Walls | $652 | $1,581 | $873 | $1176 |
| Class 35 Windows | $1113 | $2,717 | $1494 | $2018 |
| R30 Under Crawlspace Floors | $1546 | $3,948 | $2117 | $2092 |
| R38 Under Crawlspace Floor | $1374 | $4,238 | $2054 | $2980 |
| R49 Advanced Framed Attic | $1196 | $4,395 | $1955 | $3001 |
| Class 30 Windows | $683 | $4,537 | $1598 | $2858 |
| Class 25 Windows | $88 | $4,598 | $1158 | $2634 |
| R26 Walls | -$117 | $4,571 | $995 | $2529 |
| R30 Walls | -$1146 | $4,168 | $114 | $1854 |
| R60 Advanced Framed Attic | -$2725 | $3,280 | -$1302 | $664 |

Maximum NPV = Lowest LCC

**Table G-16: Climate Zone 1 Expected Value NPV by Measure and System Type**

## Mean Net Present Value for Zone 2
## (1000 Cases)

| Measure | HP | Electric FAF | GAS FAF | Zonal |
|---|---|---|---|---|
| R21 Walls | $942 | $1,681 | $832 | $1237 |
| Class 35 Windows | $1612 | $2,890 | $1422 | $2122 |
| R30 Under Crawlspace Floors | $2294 | $4,208 | $2010 | $3057 |
| R38 Under Crawlspace Floor | $2266 | $4,547 | $1927 | $3176 |
| R49 Advanced Framed Attic | $2192 | $4,740 | $1814 | $3208 |
| Class 30 Windows | $1882 | $4,952 | $1427 | $3107 |
| Class 25 Windows | $1490 | $5,080 | $957 | $2992 |
| R26 Walls | $1340 | $5,072 | $786 | $2829 |
| R30 Walls | $504 | $4,734 | -$123 | $2191 |
| R60 Advanced Framed Attic | -$862 | $3,917 | -$1570 | $1044 |

Maximum NPV = Lowest LCC

**Table G-17: Climate Zone 2 Expected Value NPV by Measure and System Type**

## Mean Net Present Value for Zone 3
## (1000 Cases)

| Measure | HP | Electric FAF | Gas FAF | Zonal |
|---|---|---|---|---|
| R21 Walls | $1342 | $2,140 | $872 | $1569 |
| Class 35 Windows | $2315 | $3,699 | $1500 | $2708 |
| R30 Under Crawlspace Floors | $3352 | $5,430 | $2127 | $3942 |
| R38 Under Crawlspace Floor | $3505 | $5,986 | $2042 | $4209 |
| R49 Advanced Framed Attic | $3560 | $6,335 | $1925 | $4348 |
| Class 30 Windows | $3491 | $6,839 | $1518 | $4441 |
| Class 25 Windows | $3326 | $7,243 | $1018 | $4438 |
| R26 Walls | $3234 | $7,305 | $835 | $4389 |
| R30 Walls | $2592 | $7,195 | -$137 | $3891 |
| R60 Advanced Framed Attic | $1391 | $6,602 | -$1680 | $2870 |

Maximum NPV = Lowest LCC

**Table G-18: Climate Zone 3 Minimum Expected Value NPV by Measure and System Type**

## Mean Net Present Value for Zone 1
## (2000 Cases)

| Measure | Net Present Value |
|---|---|
| Floor R33 | $366 |
| Attic R25 | $489 |
| Vault R25 | $602 |
| Attic R30 | $662 |
| Vault R30 | $718 |
| Class 40 Windows | $915 |
| Class 35 Windows | $1012 |
| Class 30 Windows | $1101 |
| Walls R21 Advanced Framed | $1130 |
| Attic R38 | $1147 |
| Vault R38 | $1117 |
| Attic R49 | $1056 |
| Floor R44 | $915 |

Maximum NPV = Lowest LCC

**Table 19 - Climate Zone 1 Expected Value Mean Net Present Value Results for Manufactured Homes**

## Mean Net Present Value for Zone 2 (2000 Cases)

| Measure | Net Present Value |
|---|---|
| Floor R33 | $638 |
| Attic R25 | $858 |
| Vault R25 | $1063 |
| Attic R30 | $1184 |
| Vault R30 | $1297 |
| Class 40 Windows | $1774 |
| Class 35 Windows | $2018 |
| Class 30 Windows | $2249 |
| Walls R21 Advanced Framed | $2359 |
| Attic R38 | $2437 |
| Vault R38 | $2441 |
| Attic R49 | $2427 |
| Floor R44 | $2333 |

Maximum NPV = Lowest LCC

**Table G-20: Climate Zone 2 Expected Value Mean Net Present Value Results for Manufactured Homes**

## Mean Net Present Value for Zone 3 (2000 Cases)

| Measure | Net Present Value |
|---|---|
| Floor R33 | $792 |
| Attic R25 | $1068 |
| Vault R25 | $1325 |
| Attic R30 | $1479 |
| Vault R30 | $1624 |
| Class 40 Windows | $2249 |
| Class 35 Windows | $2567 |
| Class 30 Windows | $2869 |
| Walls R21 Advanced Framed | $3017 |
| Attic R38 | $3124 |
| Vault R38 | $3141 |
| Attic R49 | $3146 |
| Floor R44 | $3062 |

Maximum NPV = Lowest LCC

**Table G-21: Climate Zone 3 Expected Value Mean Net Present Value Results for Manufactured Homes**

**Table G-22: Economic Feasibility of Regionally Cost-Effective Thermal Envelop Measures for New Electrically Heated Site Built and Manufactured Homes**

| | Site Built | | | Manufactured | | |
|---|---|---|---|---|---|---|
| | Code Avg (kWh/sq.ft.yr) | MCS **(kWh/sq.ft.yr)** | Min LCC **(kWh/sq.ft.yr)** | Current Practice **(kWh/sq.ft.yr)** | MCS **(kWh/sq.ft.yr)** | Min LCC **(kWh/sq.ft.yr)** |
| Heating Zone 1 | 3.3 | 2.6 | 2.3 | 4.3 | 2.6 | 2.6 |
| Heating Zone 2 | 5.3 | 4.3 | 3.9 | 6.2 | 3.9 | 3.9 |
| Heating Zone 3 | 6.8 | 5.4 | 4.8 | 7.7 | 4.8 | 4.8 |

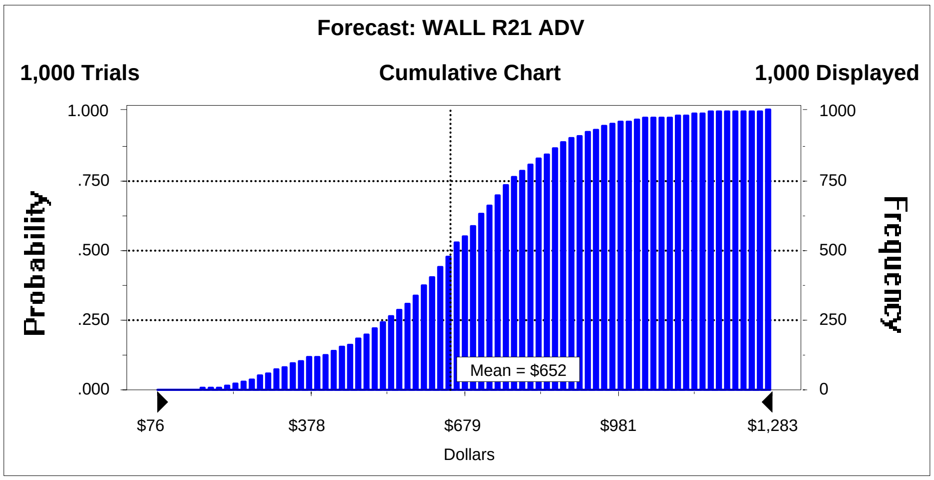


**Figure G-13: Climate Zone 1 R21 Above Grade Wall NPV Results for Heat Pumps**

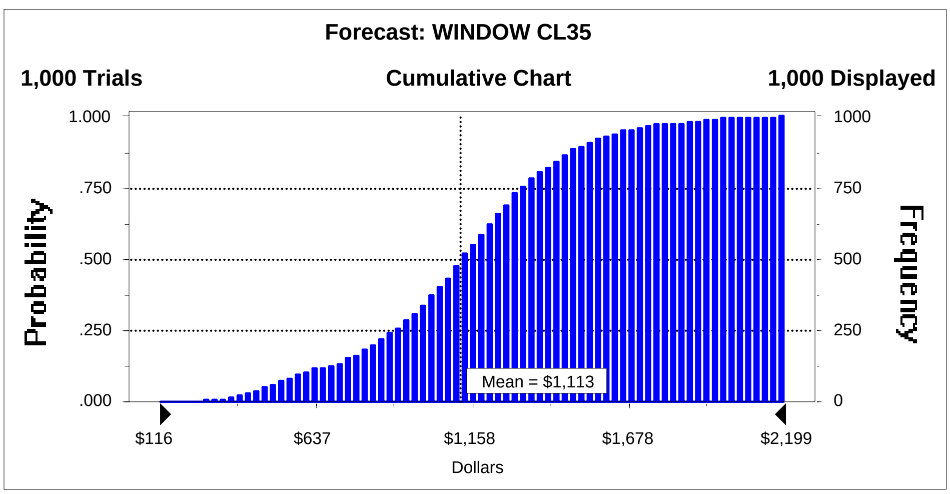


**Figure G-14: Climate Zone 1 Class 35 Window NPV Results for Heat Pumps**

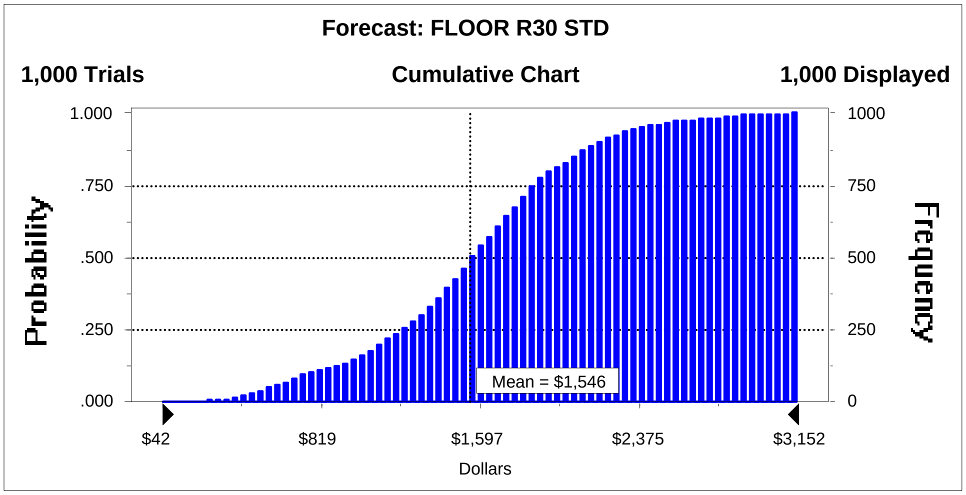


**Figure G-15: Climate Zone 1 R30 Under floor NPV Results for Heat Pumps**

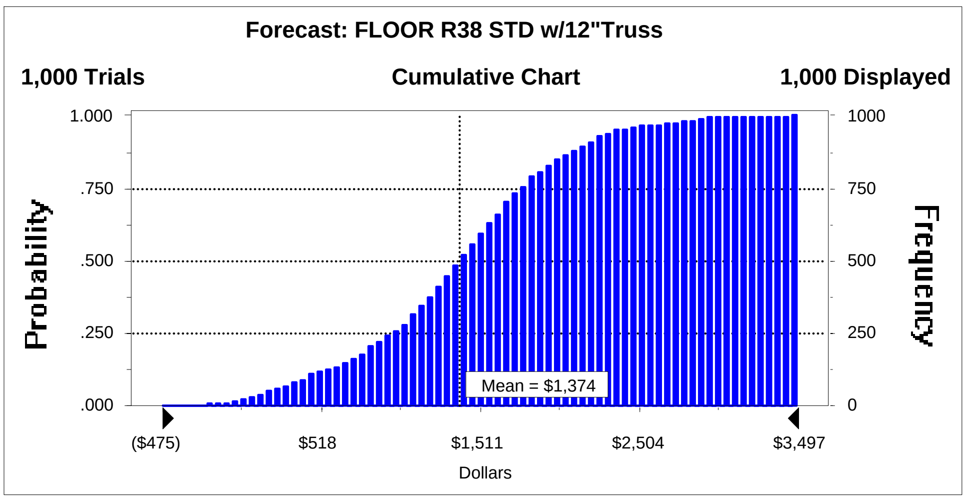


**Figure G-16: Climate Zone 1 R38 Under floor NPV Results for Heat Pump**

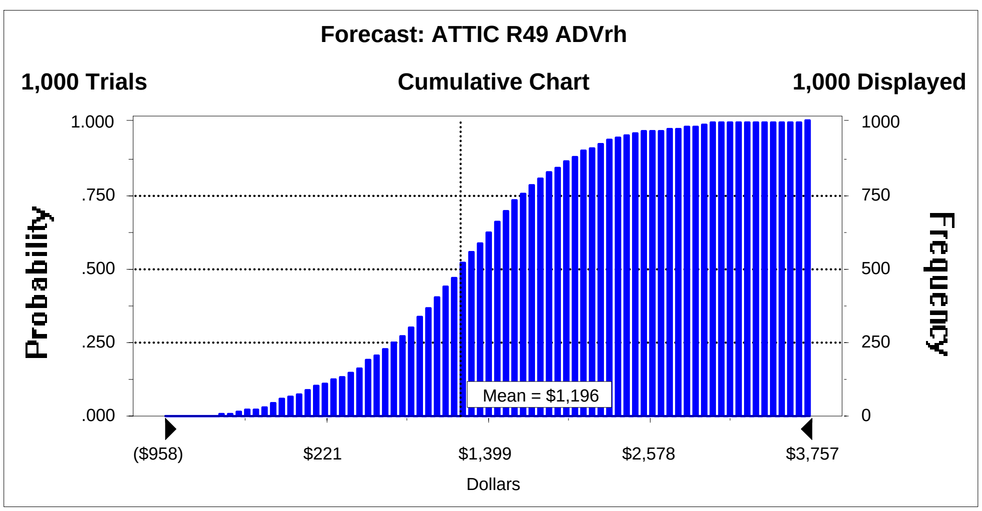


**Figure G-17: Climate Zone 1 R49 Advance Framed Attic NPV Results for Heat Pumps**

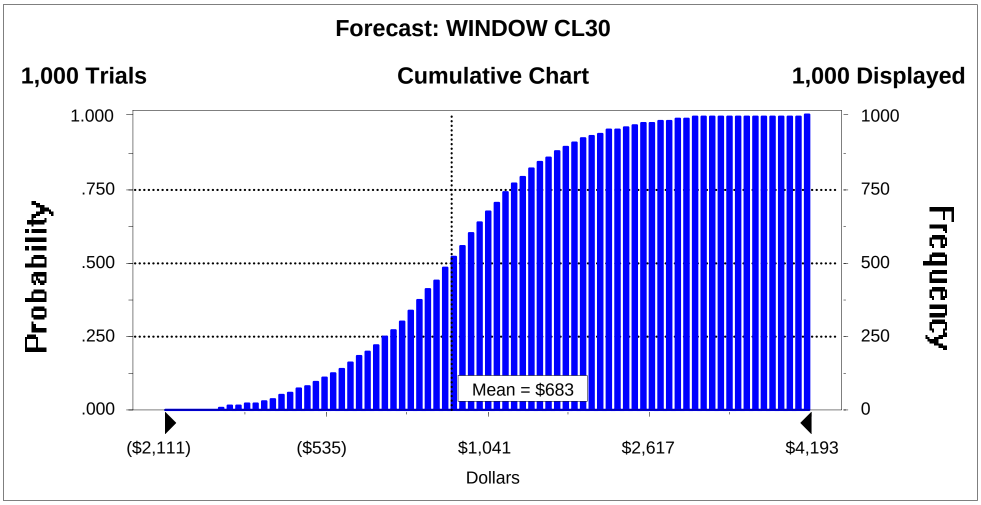


**Figure G-18: Climate Zone 1 Class 30 Window NPV Results for Heat Pumps**

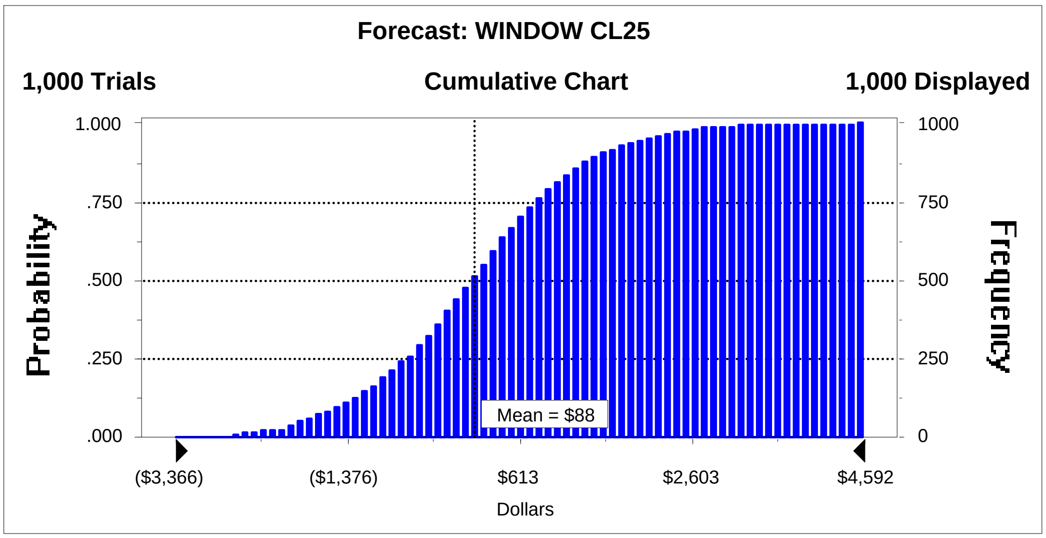


**Figure G-19: Climate Zone 1 Class 25 Window NPV Results for Heat Pumps**

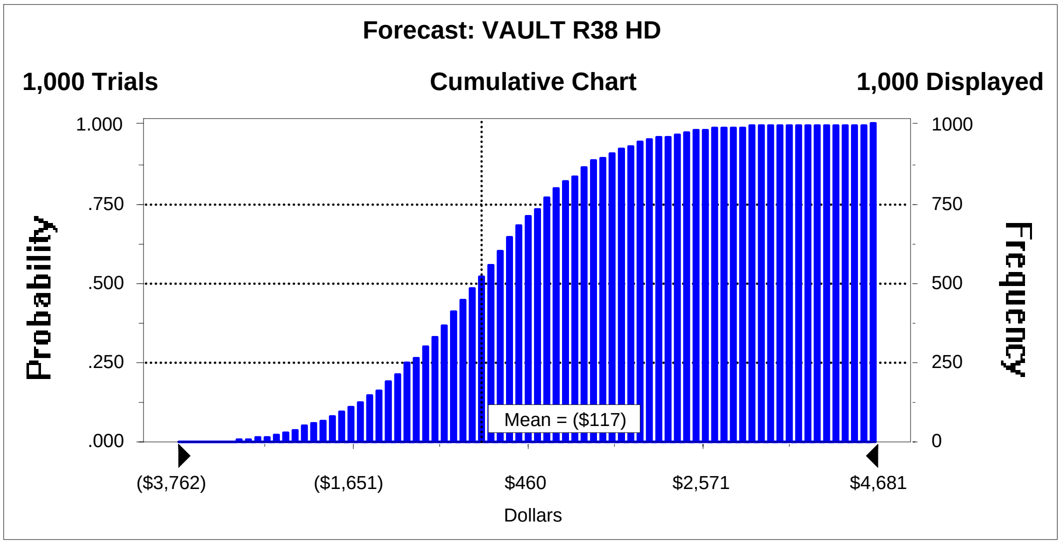


**Figure G-20: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Heat Pumps**

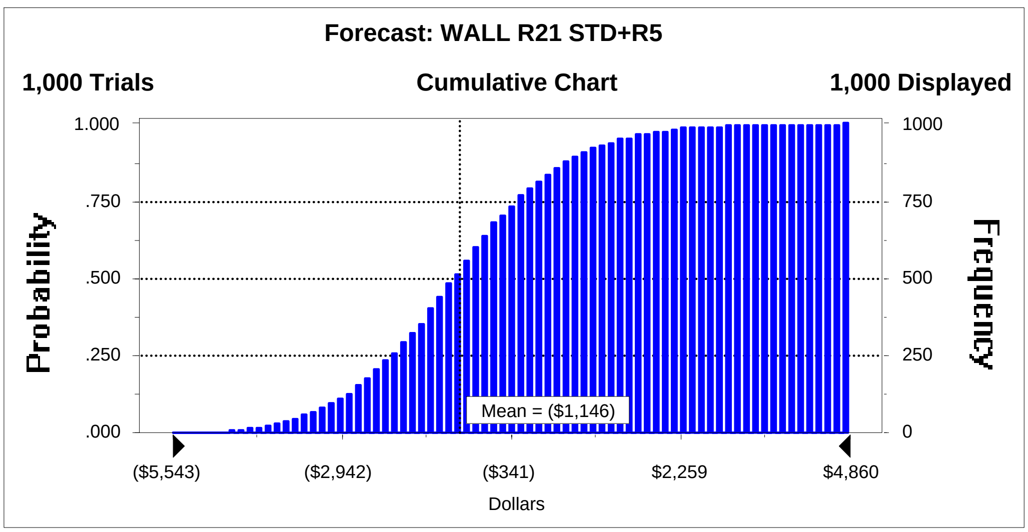


**Figure G-21: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Heat Pumps**

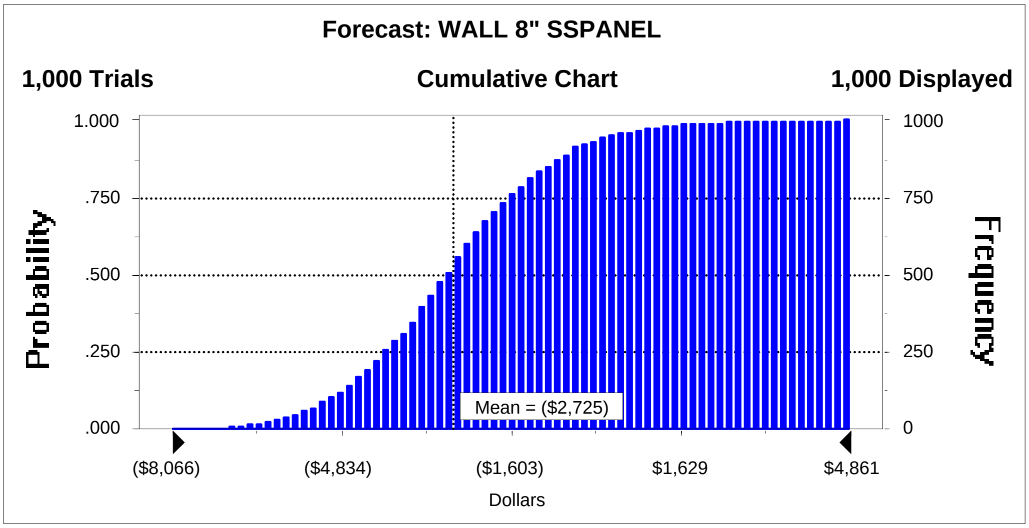


**Figure G-22: Climate Zone 1 R33 Wall NPV Results for Heat Pumps**

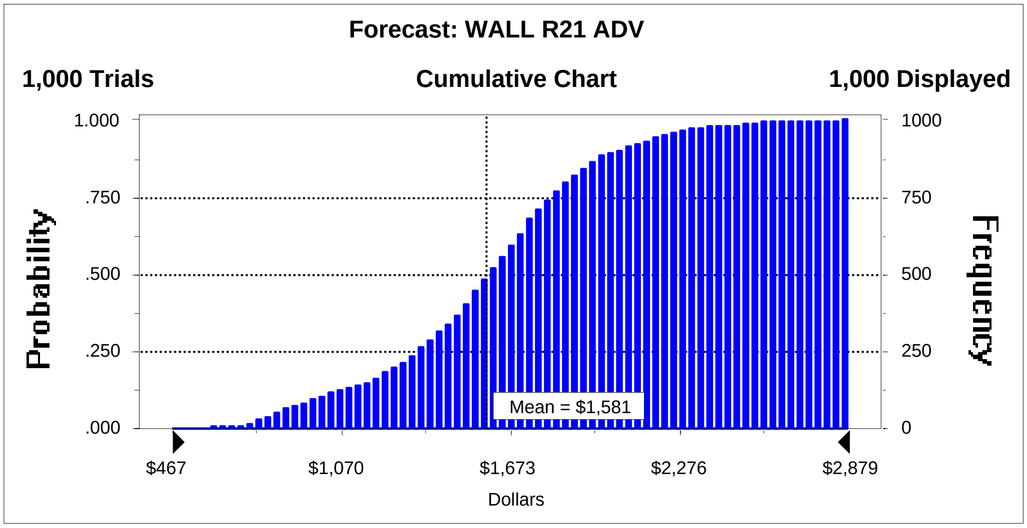


**Figure G-23: Climate Zone 1 R21 Above Grade Wall NPV Results for Electric FAF**

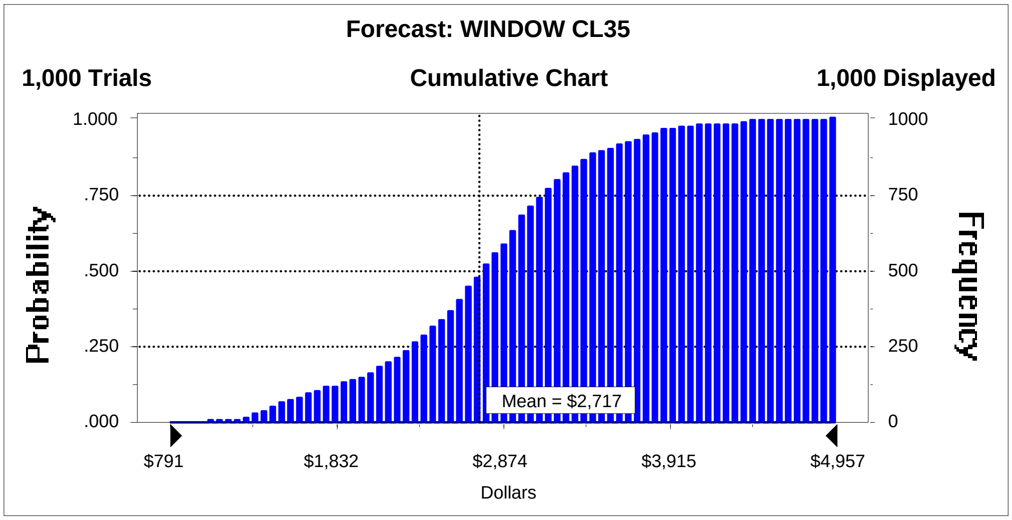


**Figure G-24: Climate Zone 1 Class 35 Window NPV Results for Electric FAF**

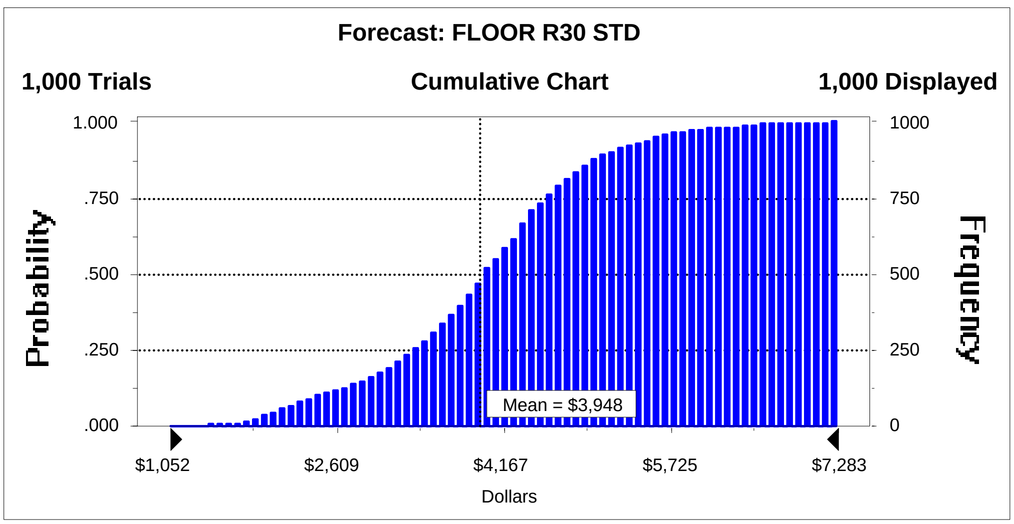


**Figure G-25: Climate Zone 1 R30 Under floor NPV Results for Electric FAF**

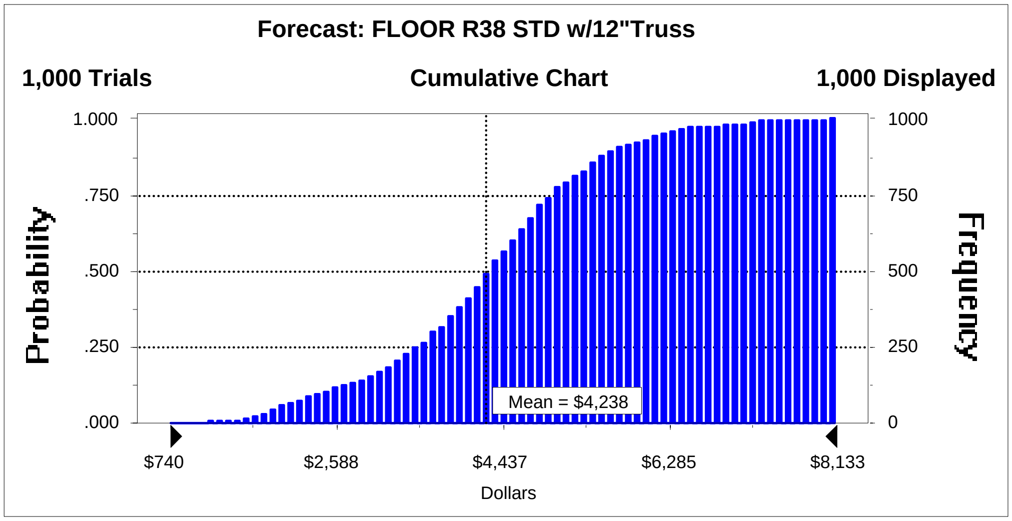


**Figure G-26: Climate Zone 1 R38 Under floor NPV Results for Electric FAF**

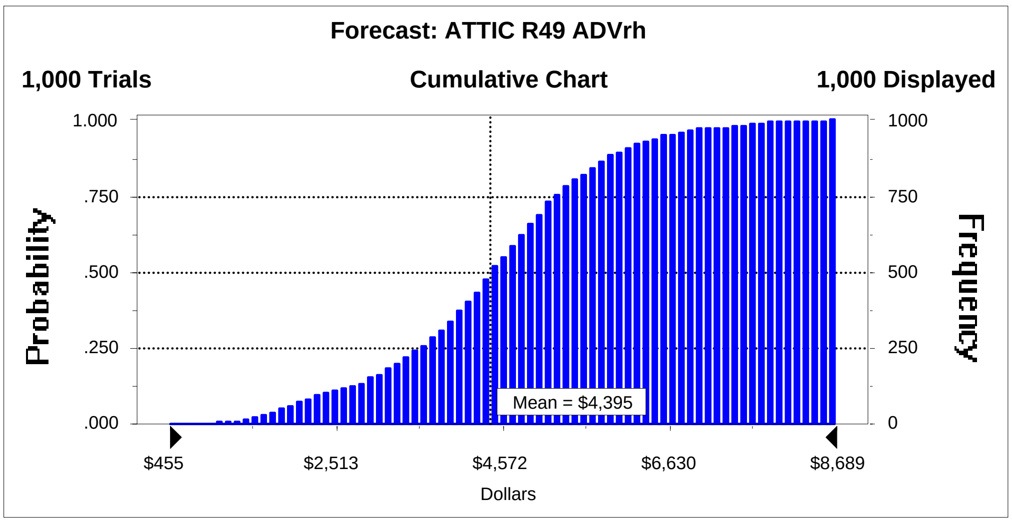


**Figure G-27: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric FAF**

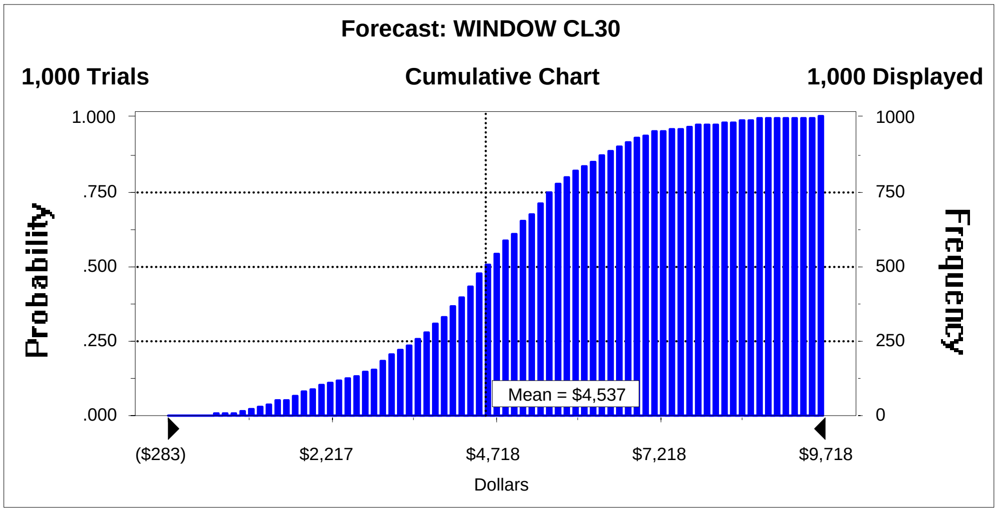


**Figure G-28: Climate Zone 1 Class 30 Window NPV Results for Electric FAF**

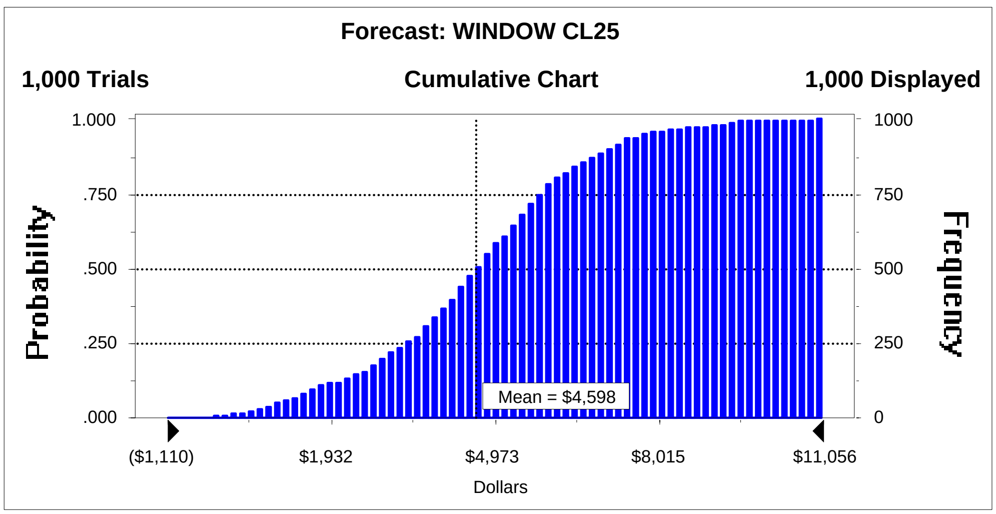


**Figure G-29: Climate Zone 1 Class 25 Window NPV Results for Electric FAF**

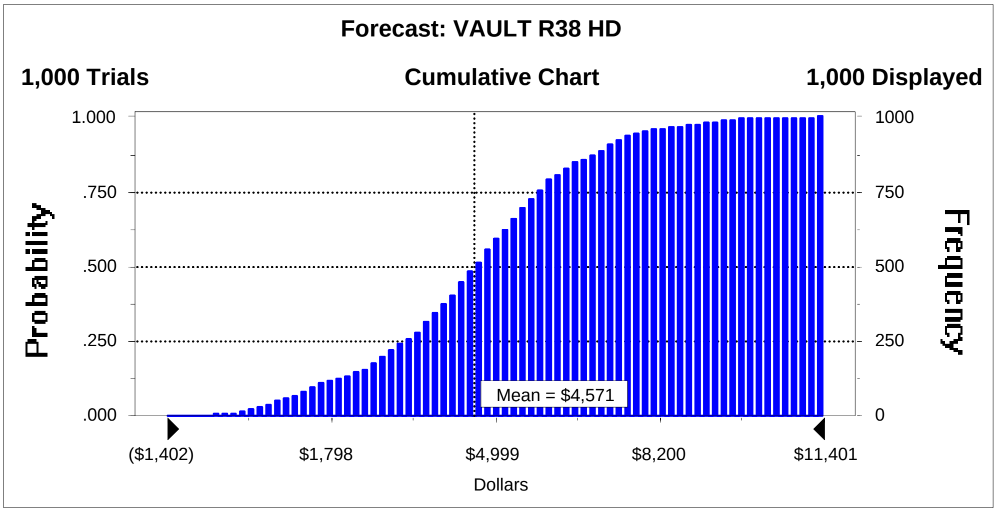


**Figure G-30: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric FAF**

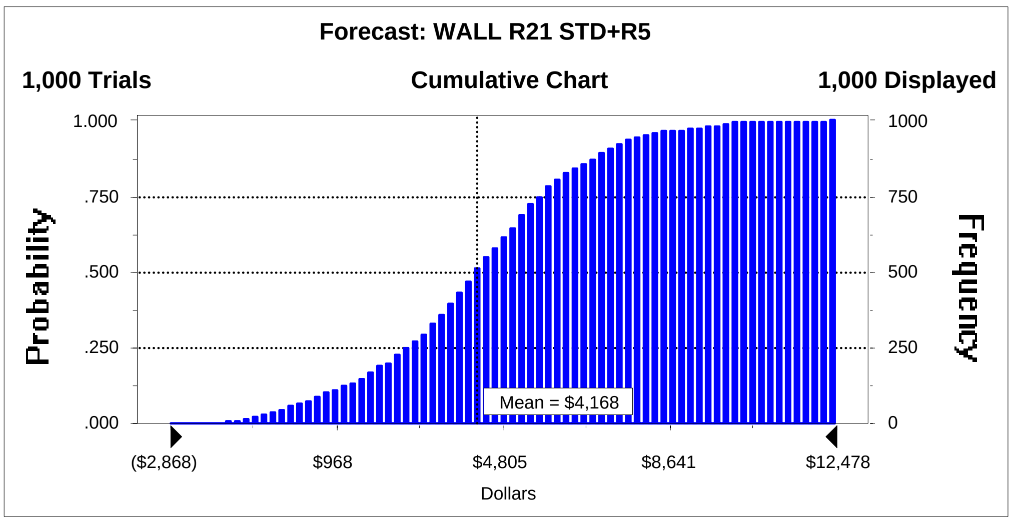


**Figure G-31: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric FAF**

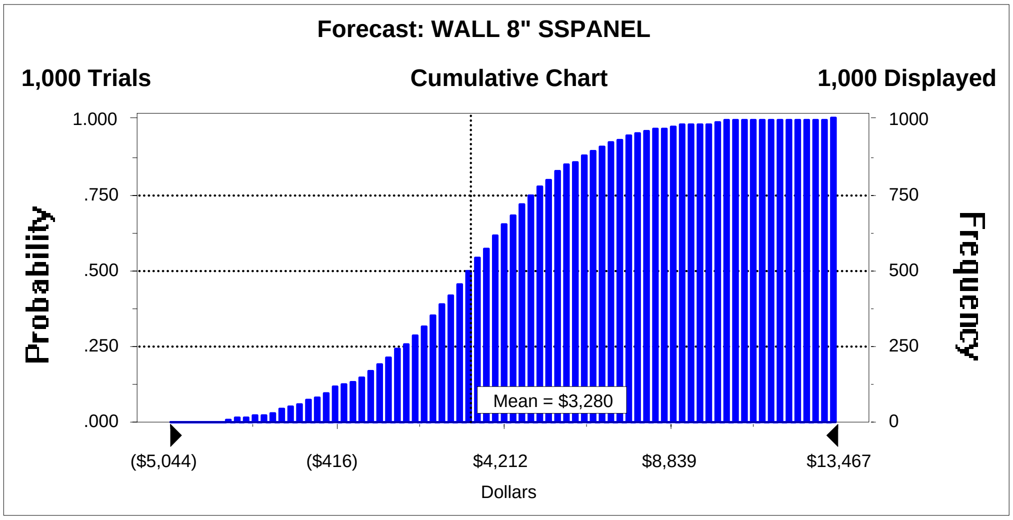


**Figure G-32: Climate Zone 1 R33 Wall NPV Results for Electric FAF**

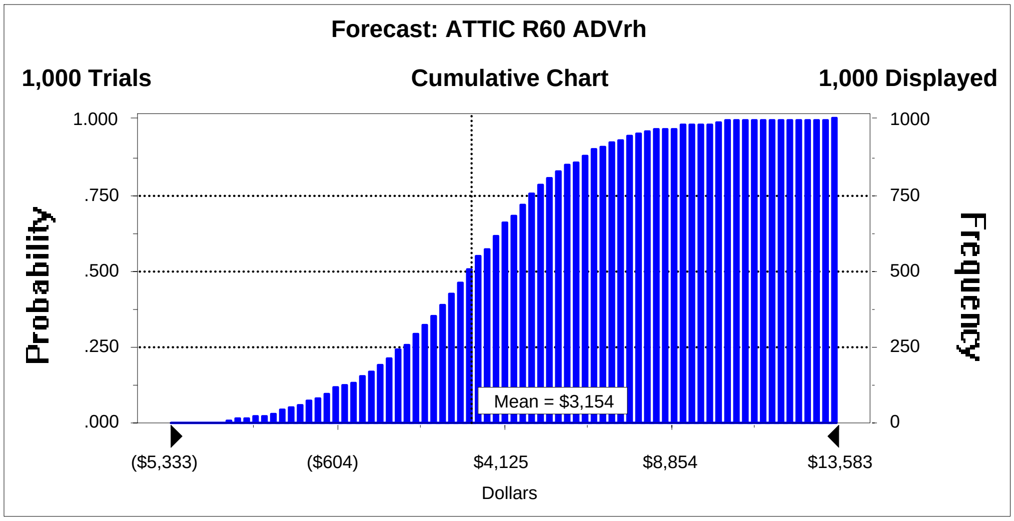


**Figure G-33: Climate Zone 1 R60 Attic NPV Results for Electric FAF**

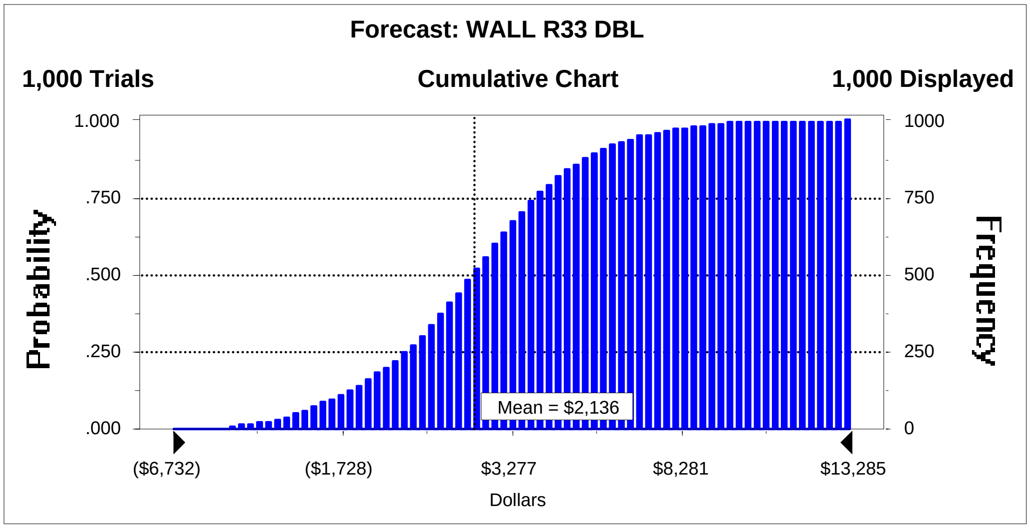


**Figure G-34: Climate Zone 1 NPV Results for Electric FAF**

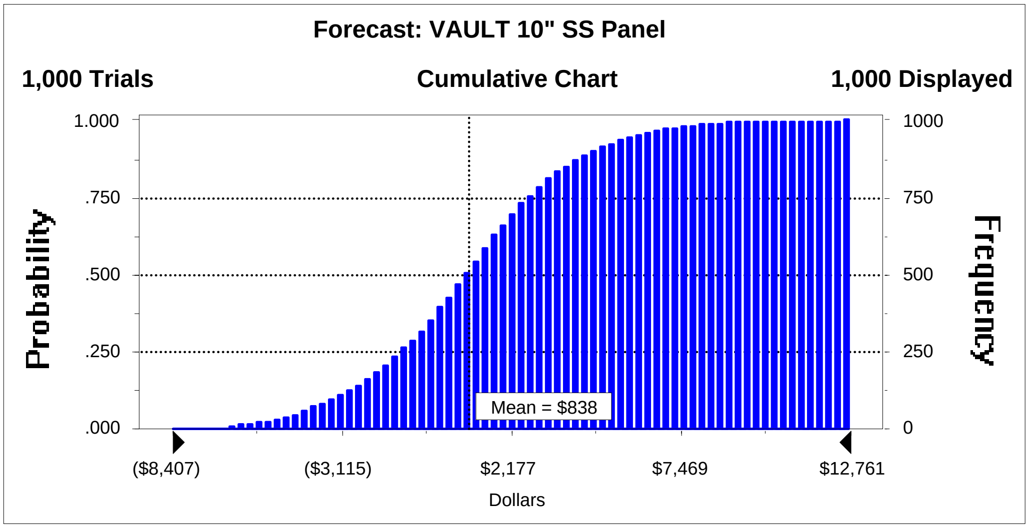


**Figure G-35: Climate Zone 1 R38 Wall NPV Results for Electric FAF**

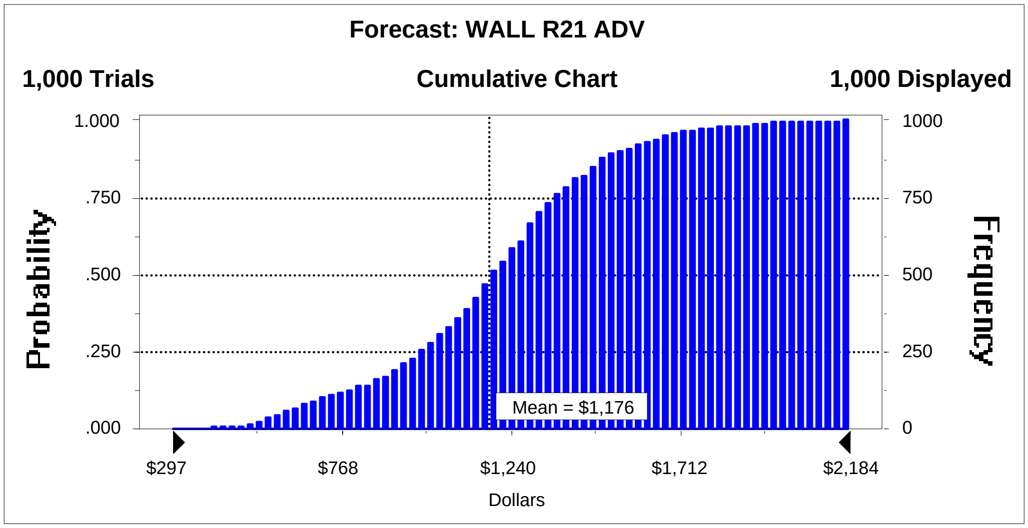


**Figure G-36: Climate Zone 1 R21 Wall NPV for Electric Zonal**

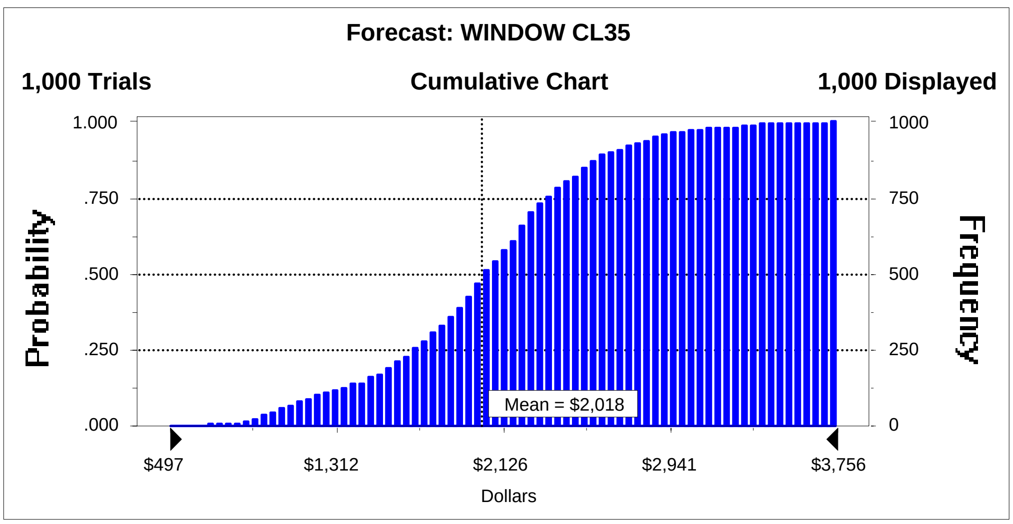


**Figure G-37: Climate Zone 1 Class 35 Windows NPV Results for Electric Zonal**

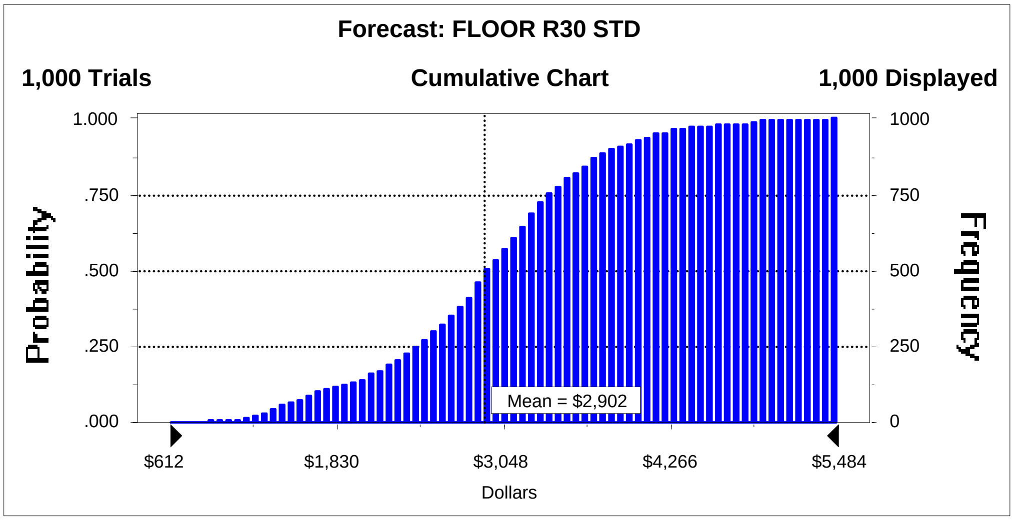


**Figure G-38: Climate Zone 1 R30 Under floor NPV Results for Electric Zonal**

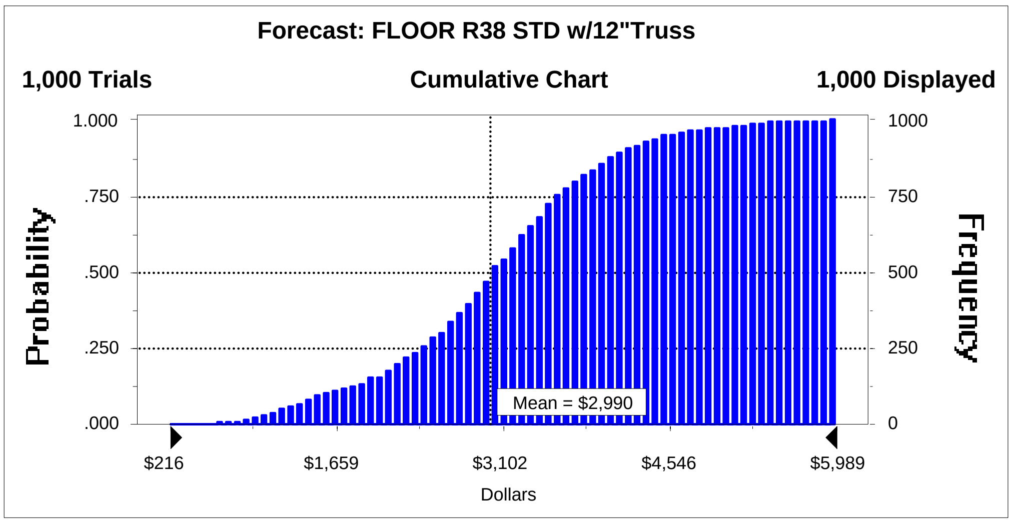


**Figure G-39: Climate Zone 1 R38 Under floor NPV Results for Electric Zonal**

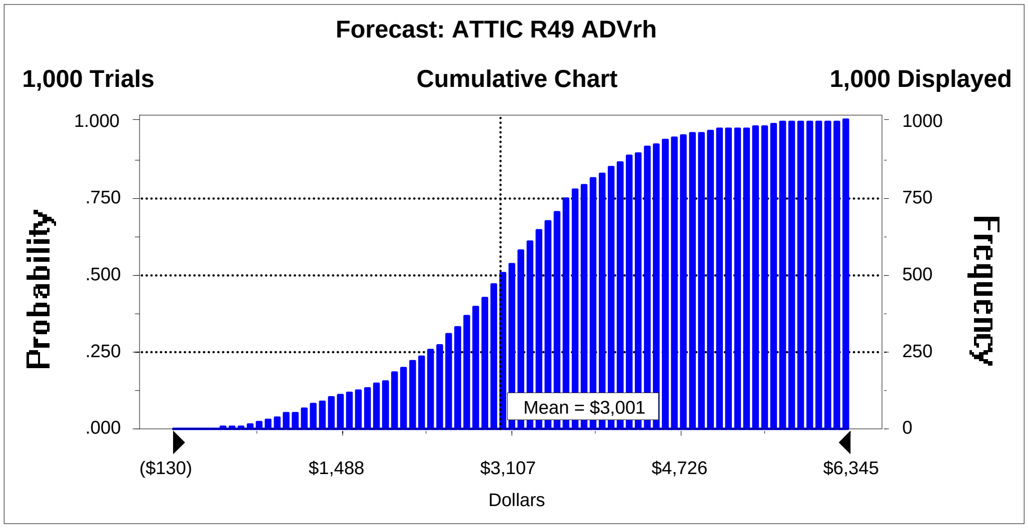


**Figure G-40: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric Zonal**

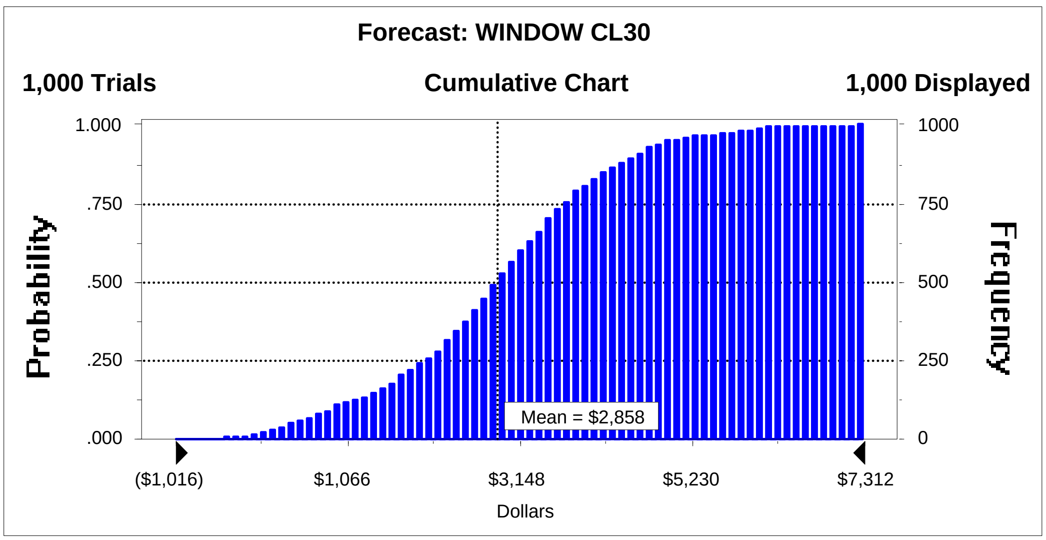


**Figure G-41: Climate Zone 1 Class 30 Window NPV Results for Electric Zonal**

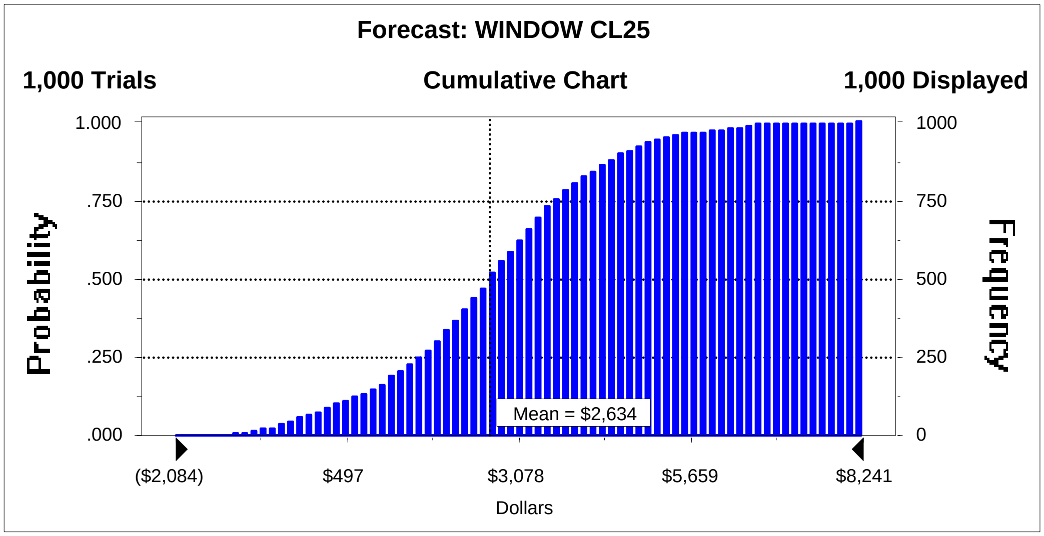


**Figure G-42: Climate Zone 1 Class 25 Window NPV Results for Electric Zonal**

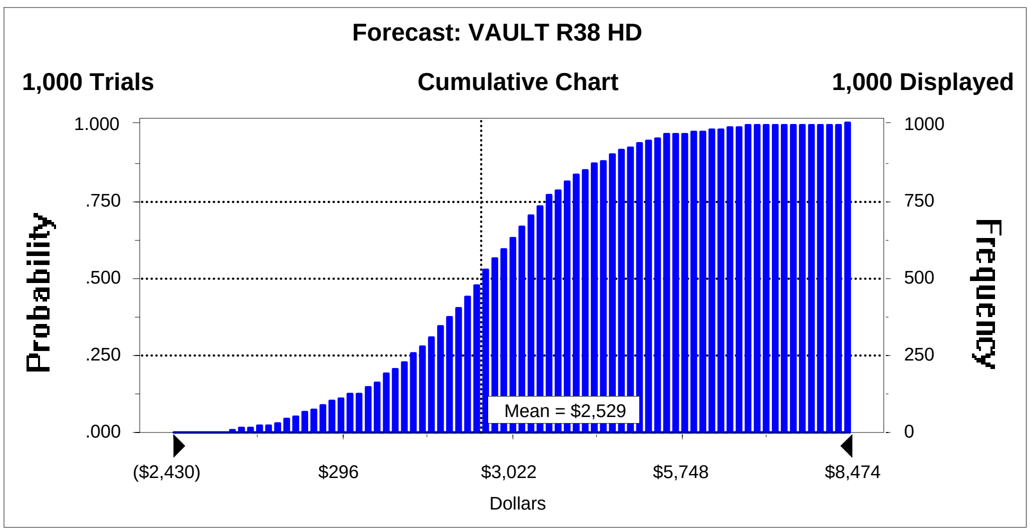


**Figure G-43: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric Zonal**

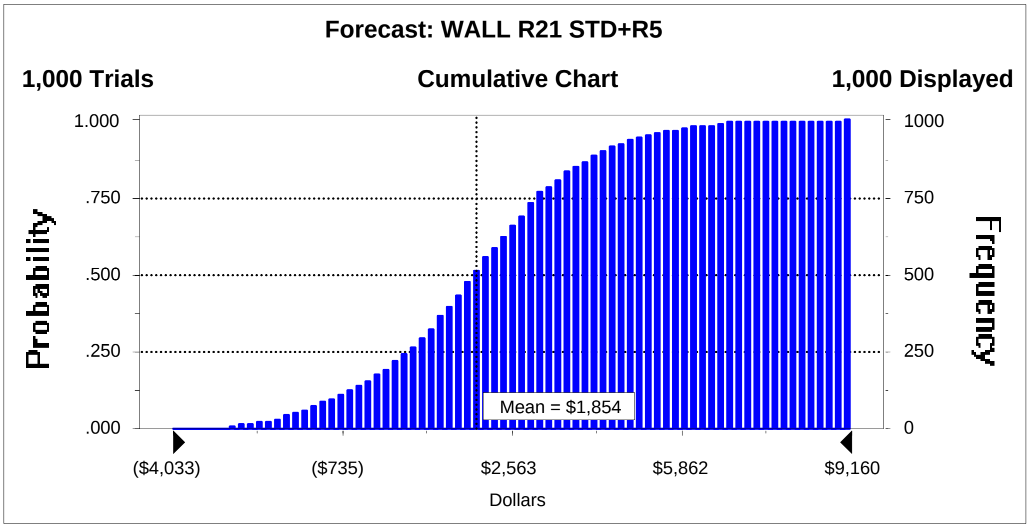


**Figure G-44: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric Zonal**

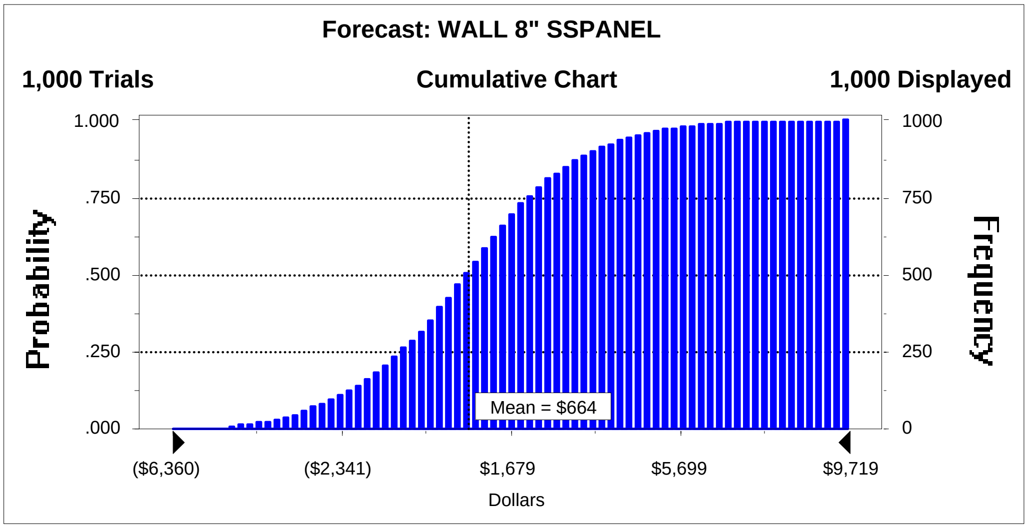


**Figure G-45: Climate Zone 1 R33 Wall NPV Results for Electric Zonal**

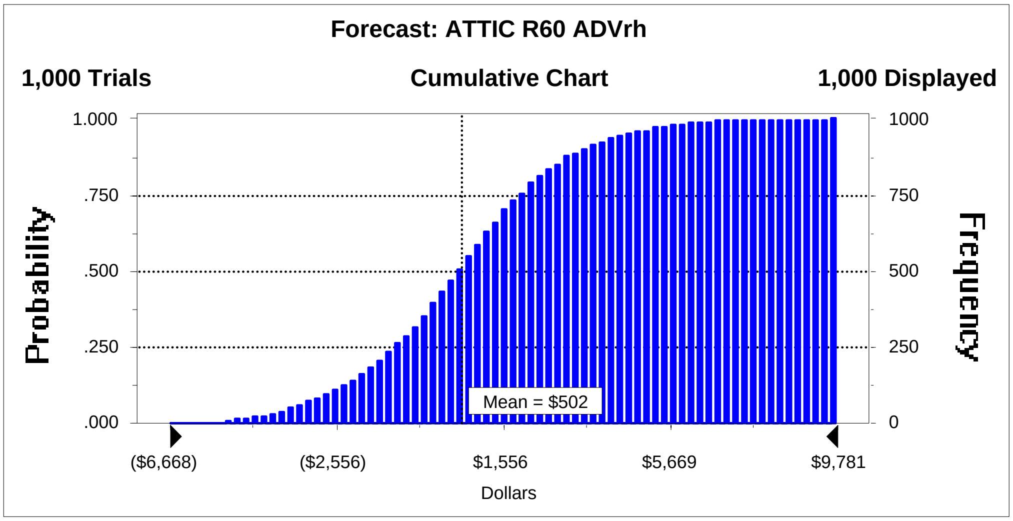


**Figure G-46: Climate Zone 1 R60 Advanced Framed Attic NPV Results for Electric Zonal**

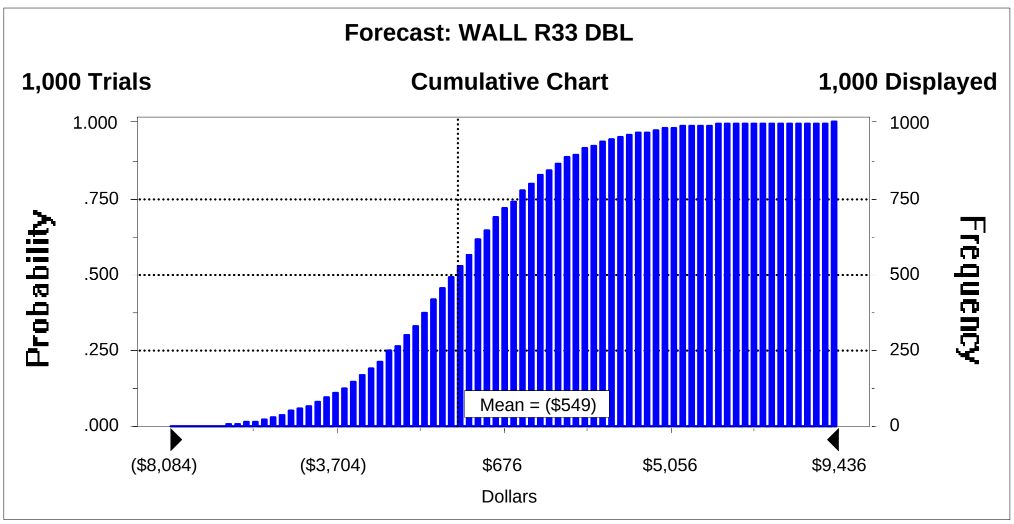


**Figure G-47: Climate Zone 1 R38 Wall NPV Results for Electric Zonal**

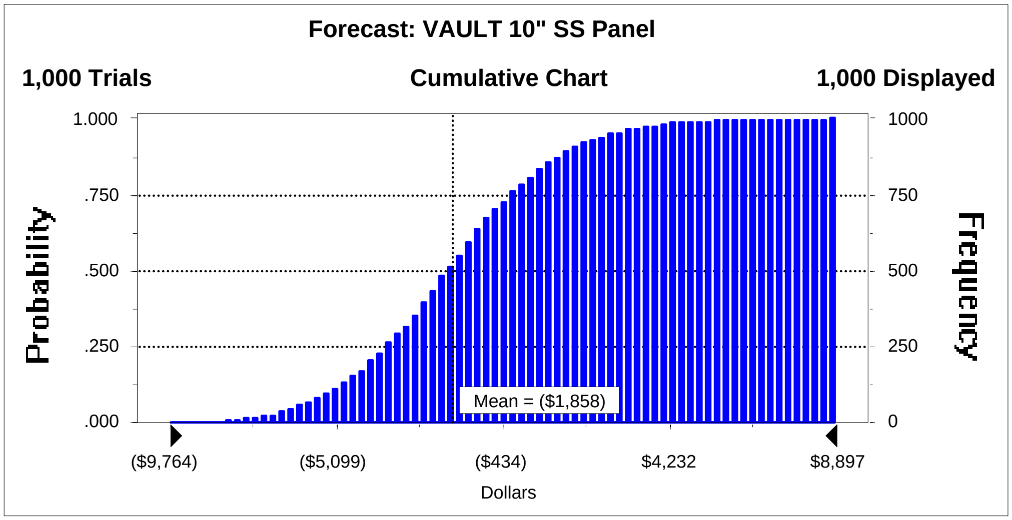


**Figure G-48: Climate Zone 1 R49 Vault NPV Results for Electric Zonal**

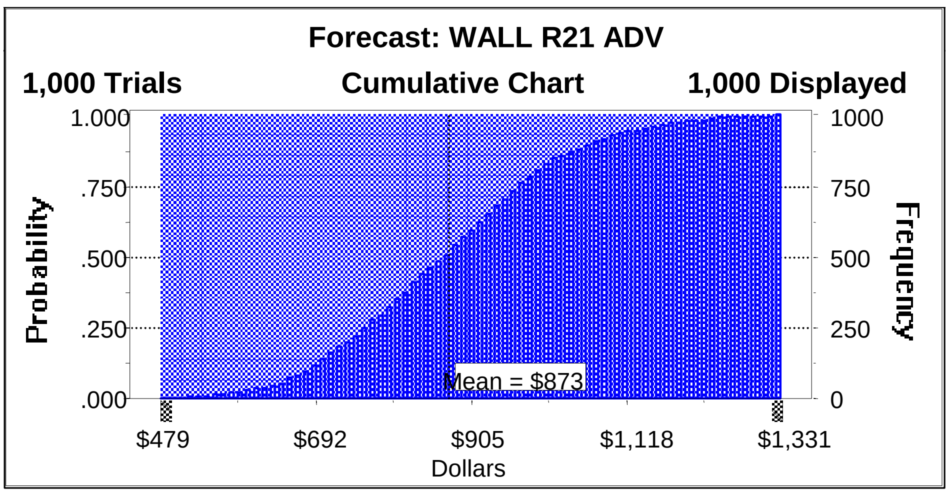


**Figure G-49: Climate Zone 1 R21 Advanced Framed Wall NPV Results for Gas FAF**

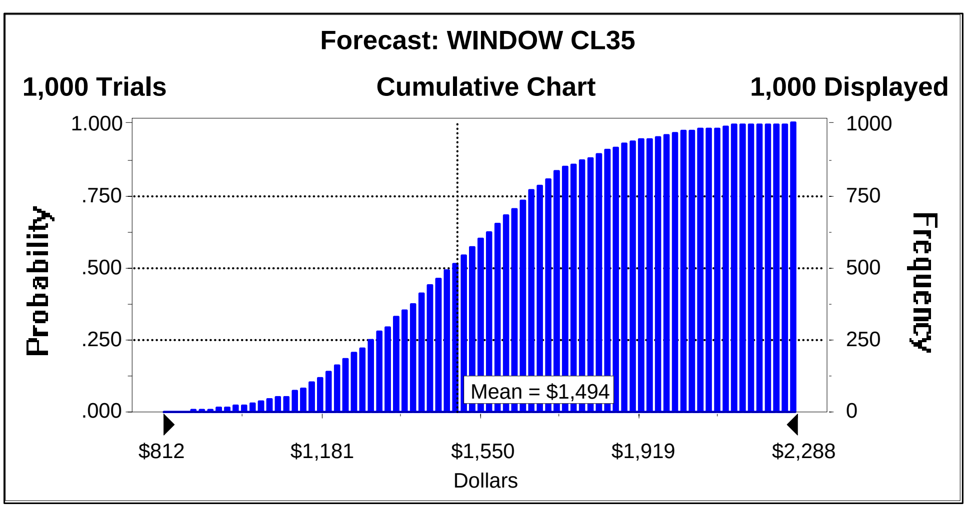


**Figure G-50: Climate Zone 1 Class 35 Window NPV Results for Gas FAF**

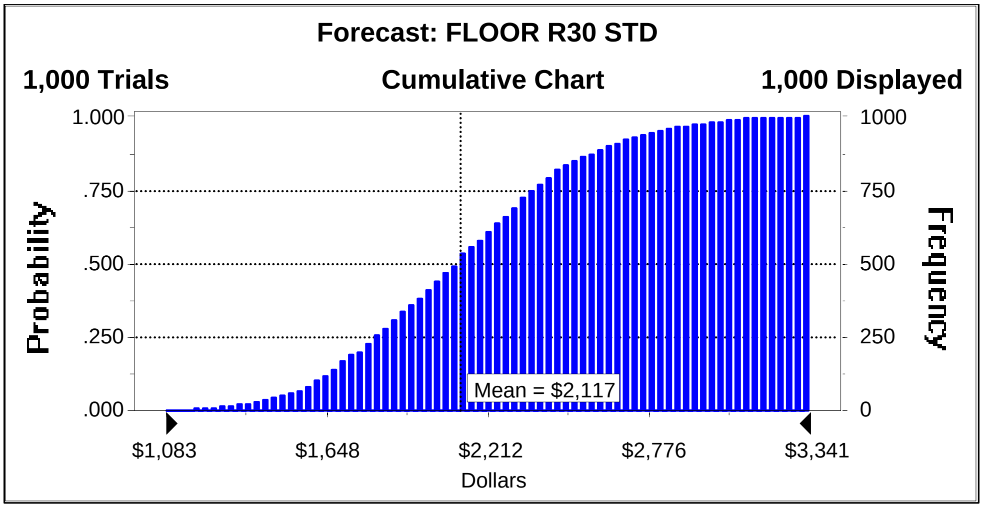


**Figure G-51: Climate Zone 1 R30 Under floor NPV Results for Gas FAF**

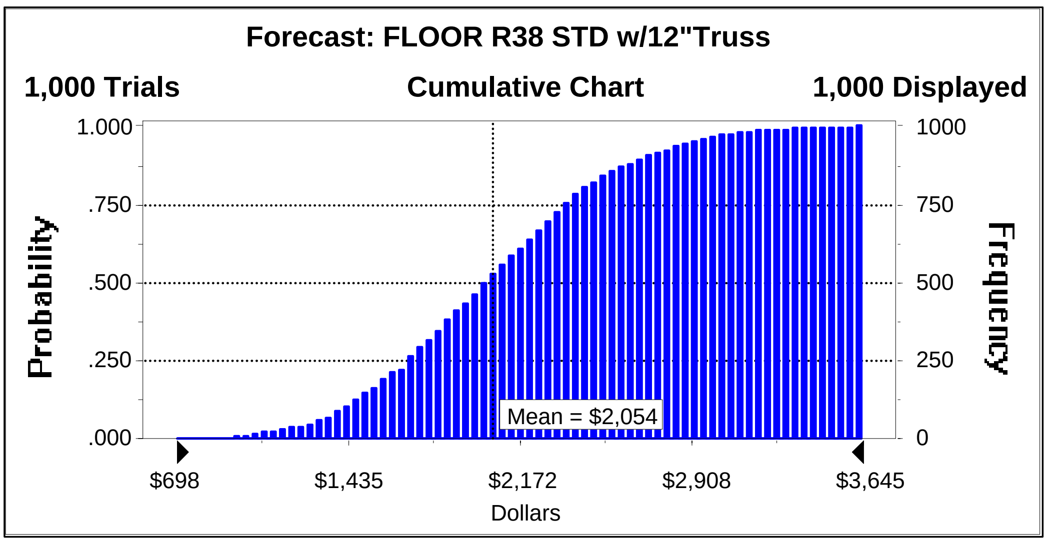


**Figure G-52: Climate Zone 1 R38 Under floor NPV Results for Gas FAF**

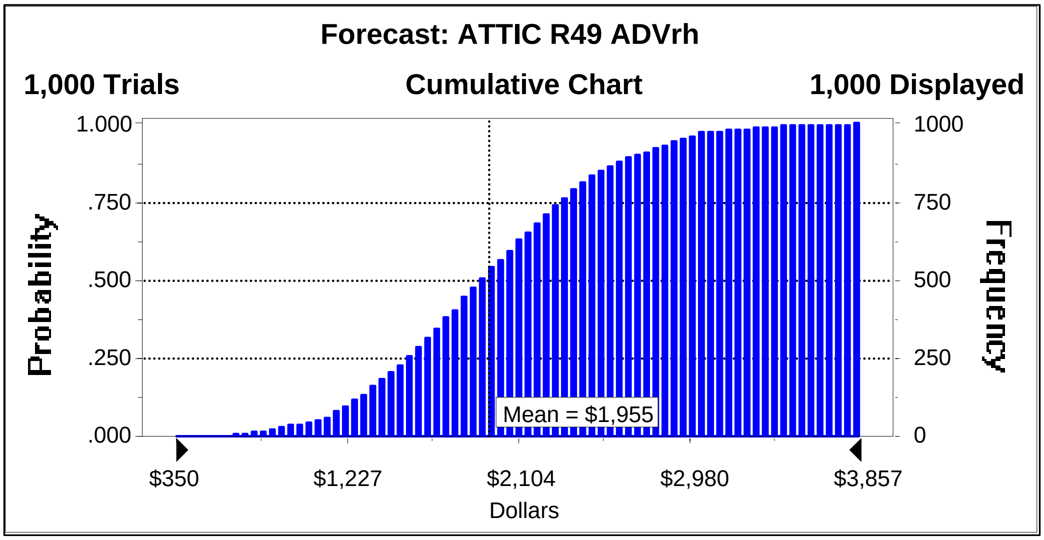


**Figure G-53: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Gas FAF**

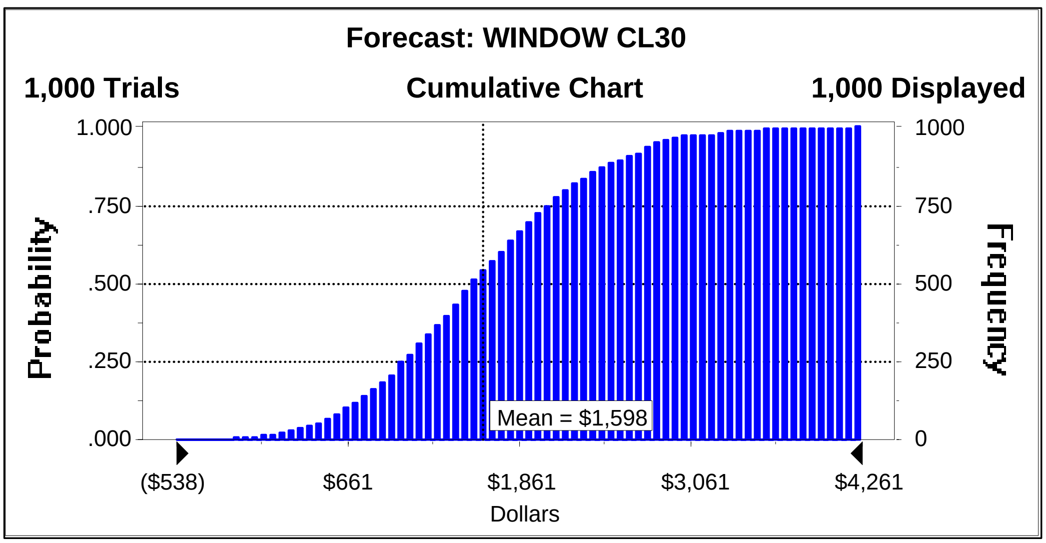


**Figure G-54: Climate Zone 1 Class 30 Window NPV Results for Gas FAF**

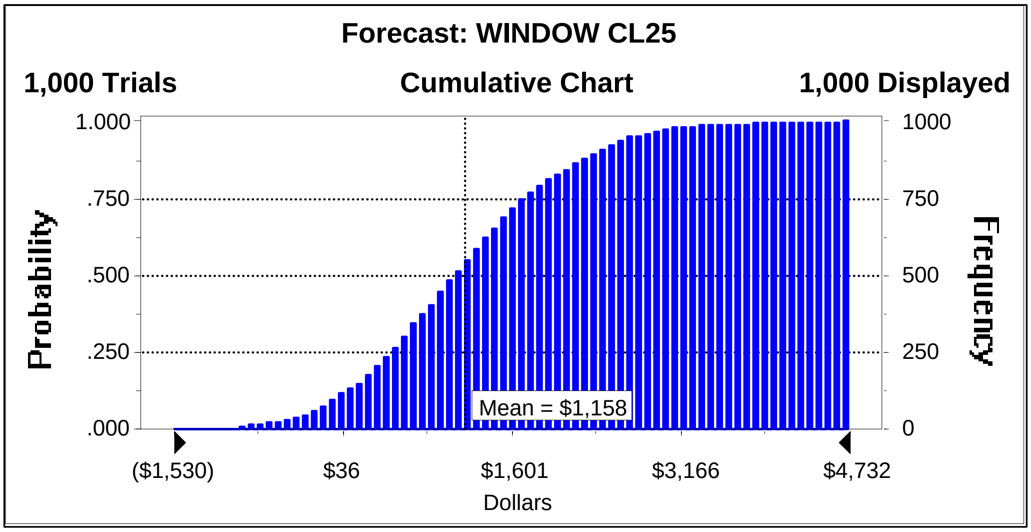


**Figure G-55: Climate Zone 1 Class 25 Window NPV Results for Gas FAF**

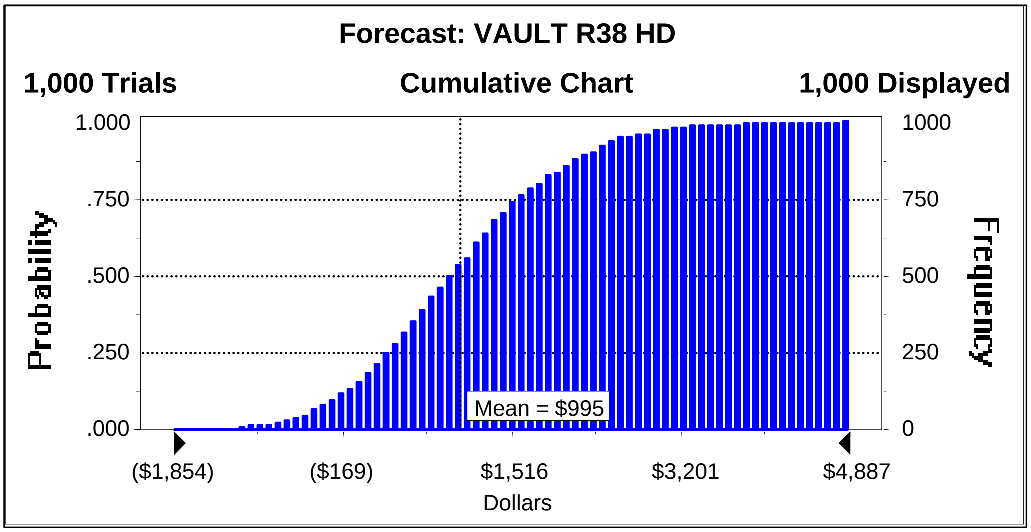


**Figure G-56: Climate Zone 1 R38 Vault NPV Results for Gas FAF**

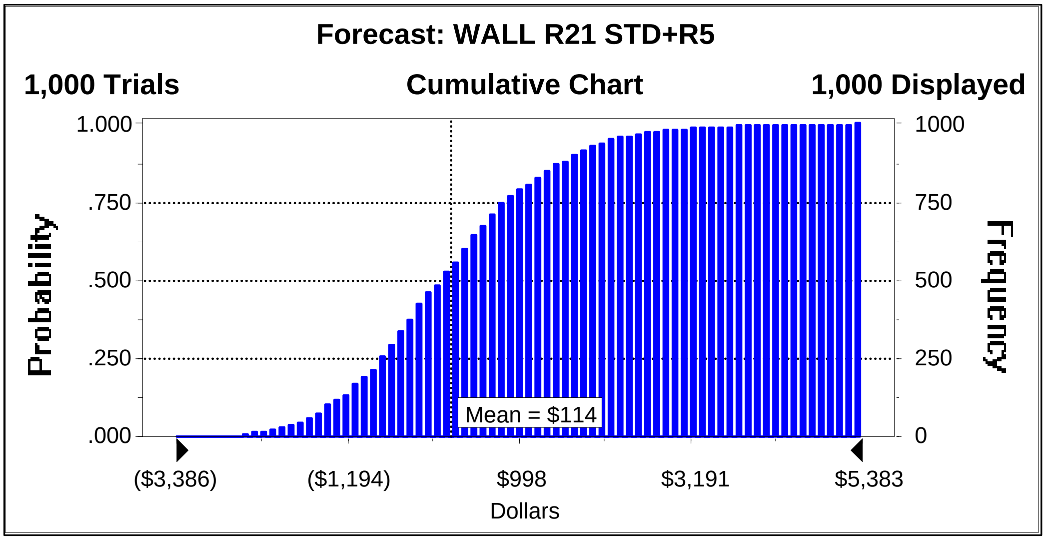


**Figure G-57: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Gas FAF**

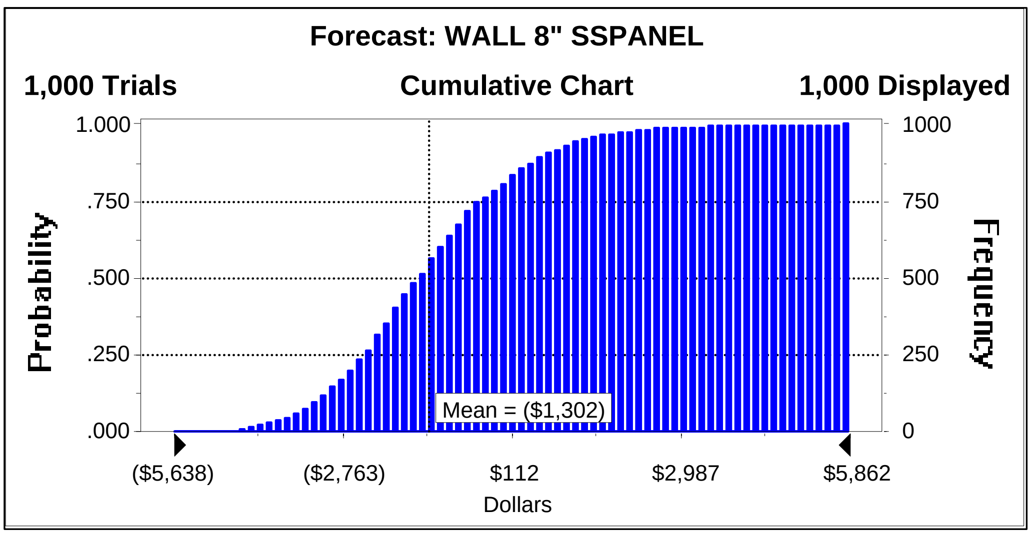


**Figure G-58: Climate Zone 1 R33 Wall NPV Results for Gas FAF**

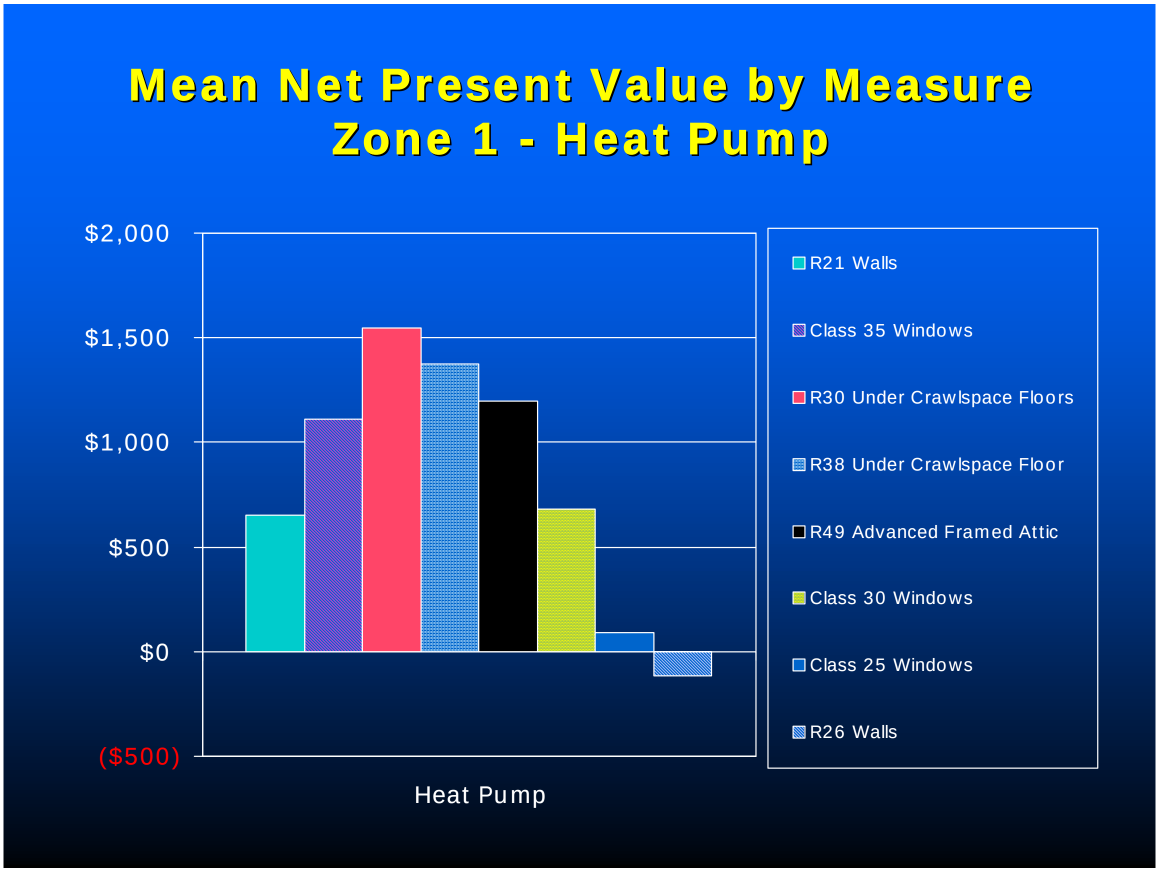


**Figure G-59: Climate Zone 1 Mean NPV by Measure for Heat Pumps**

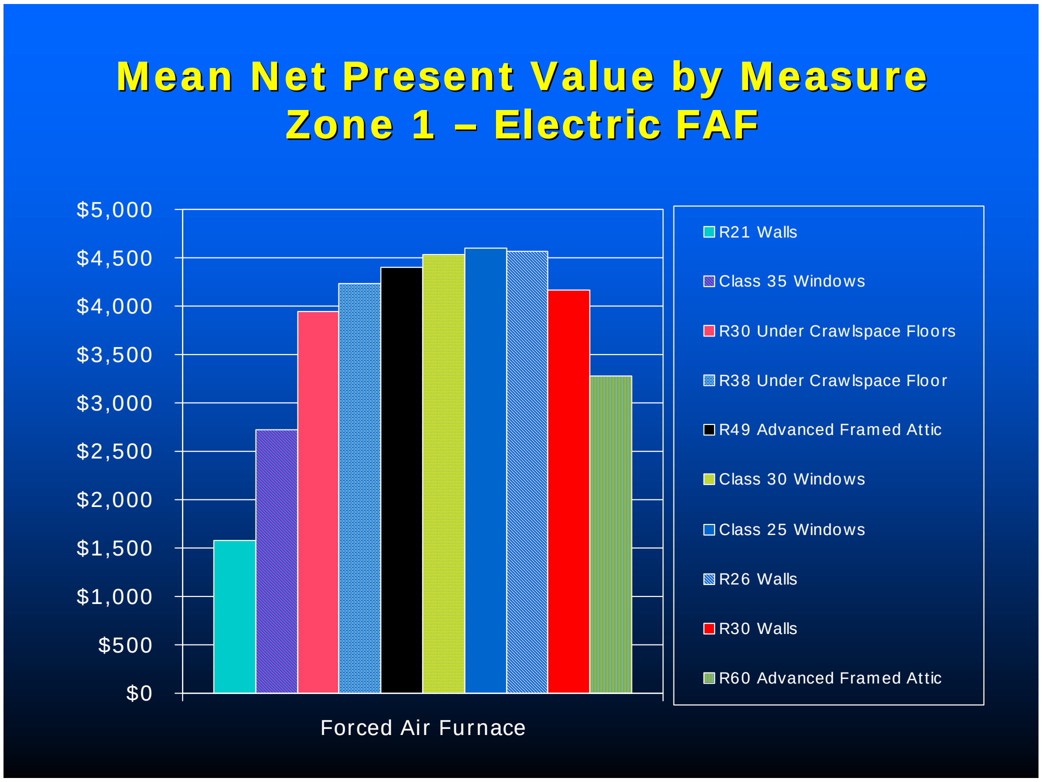


**Figure G-60: Climate Zone 1 Mean NPV by Measure for Electric FAF**

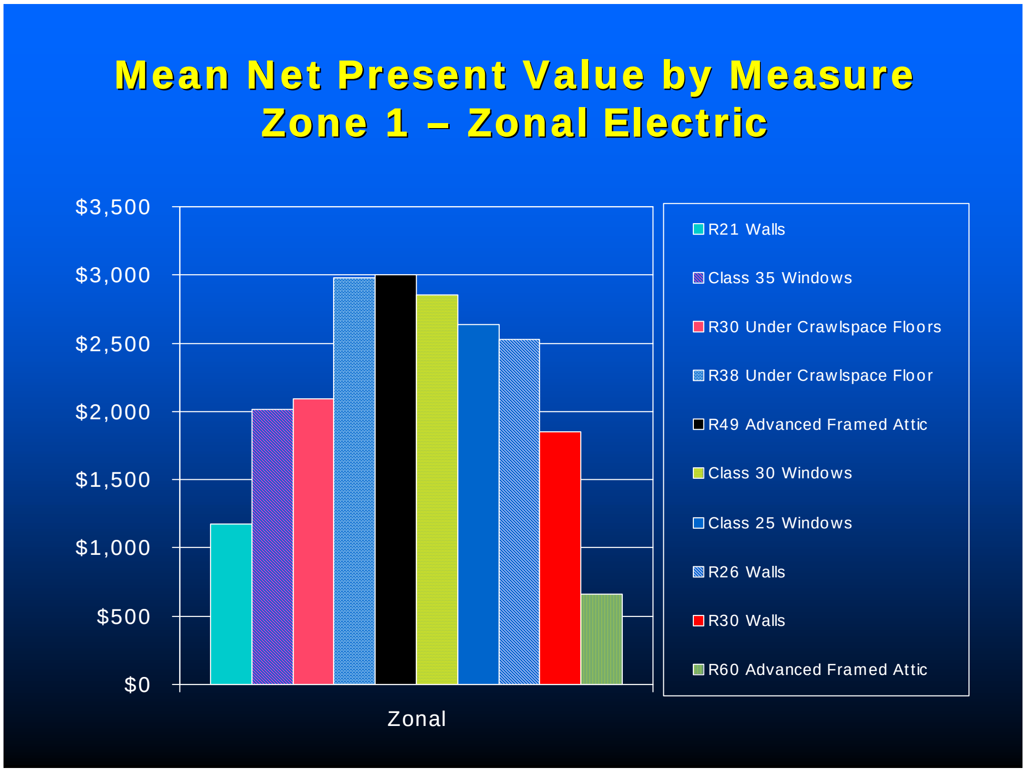


**Figure G-61: Climate Zone 1 - Mean NPV by Measure for Electric Zonal**

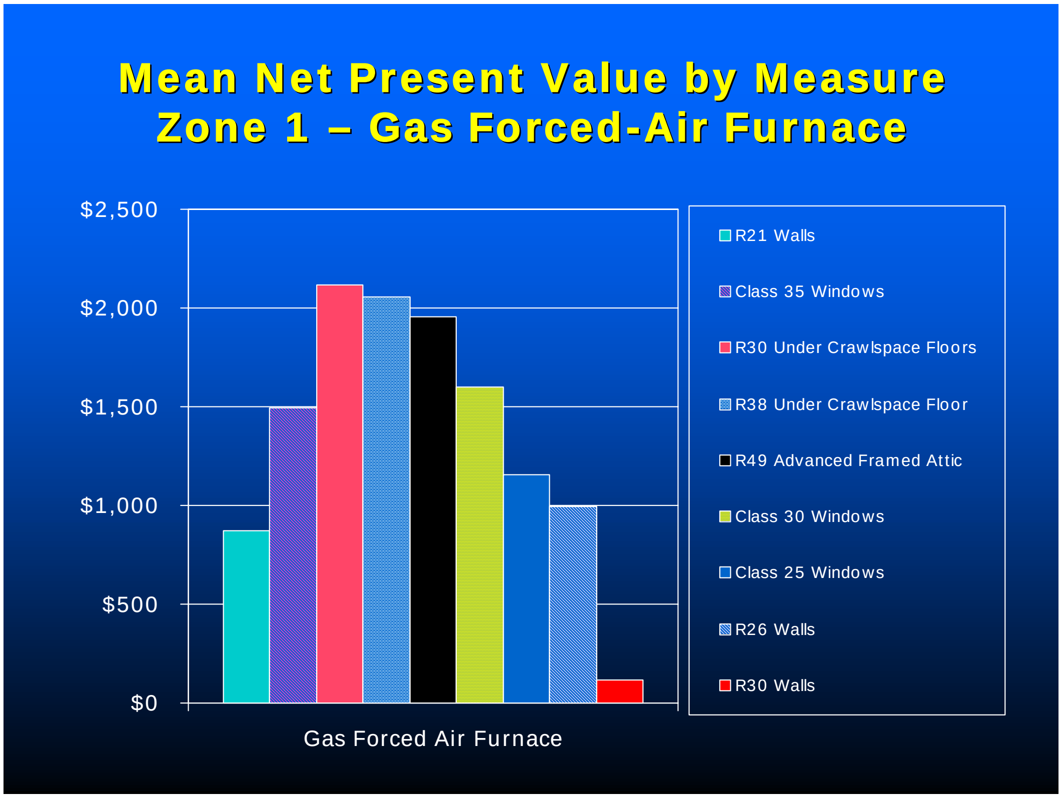


**Figure G-62: Climate Zone 1 - Mean NPV by Measure for Gas FAF**

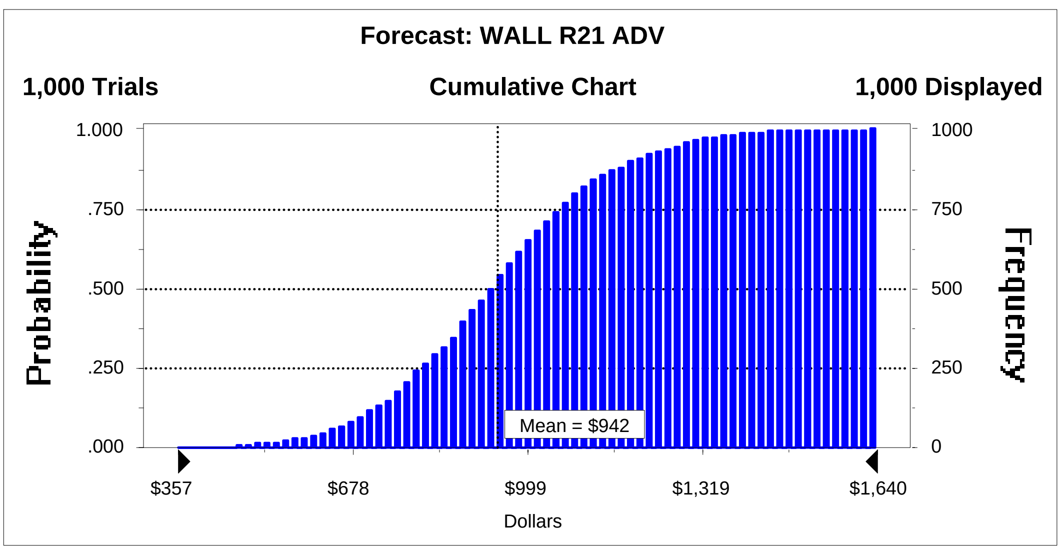


**Figure G-63: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Heat Pump**

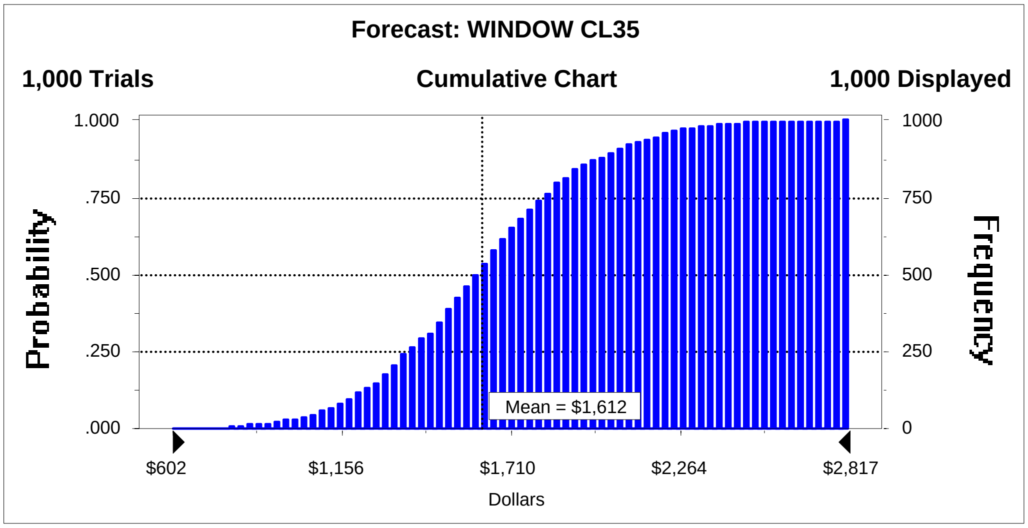


**Figure G-64: Climate Zone 2 Class 35 Window NPV Results for Heat Pumps**

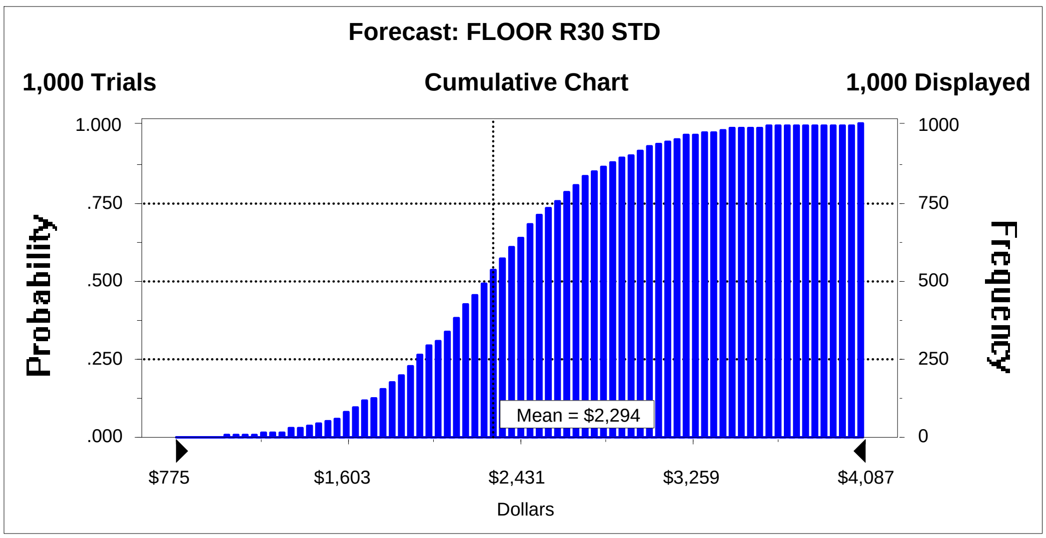


**Figure G-65: Climate Zone 2 R30 Under floor NPV Results for Heat Pumps**

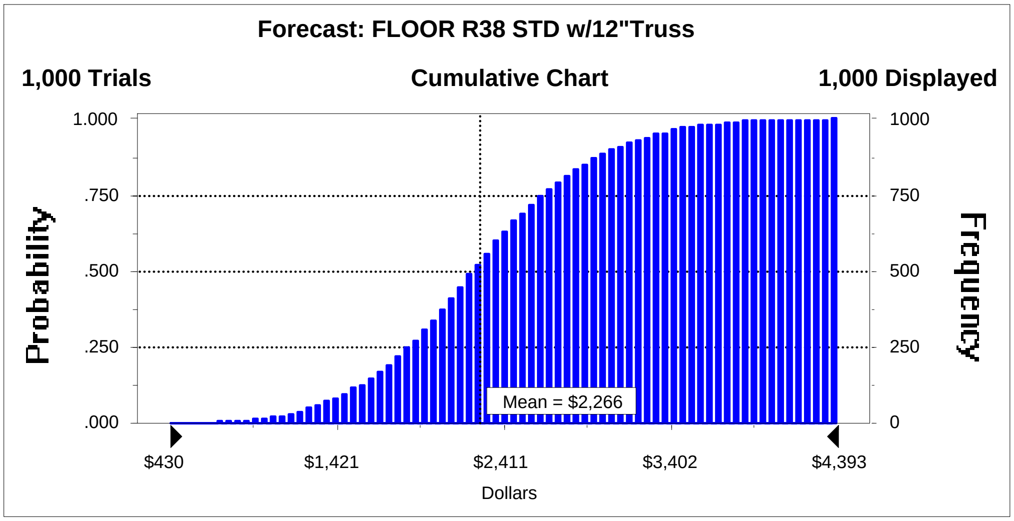


**Figure G-66: Climate Zone 2 R38 Under floor NPC Results for Heat Pumps**

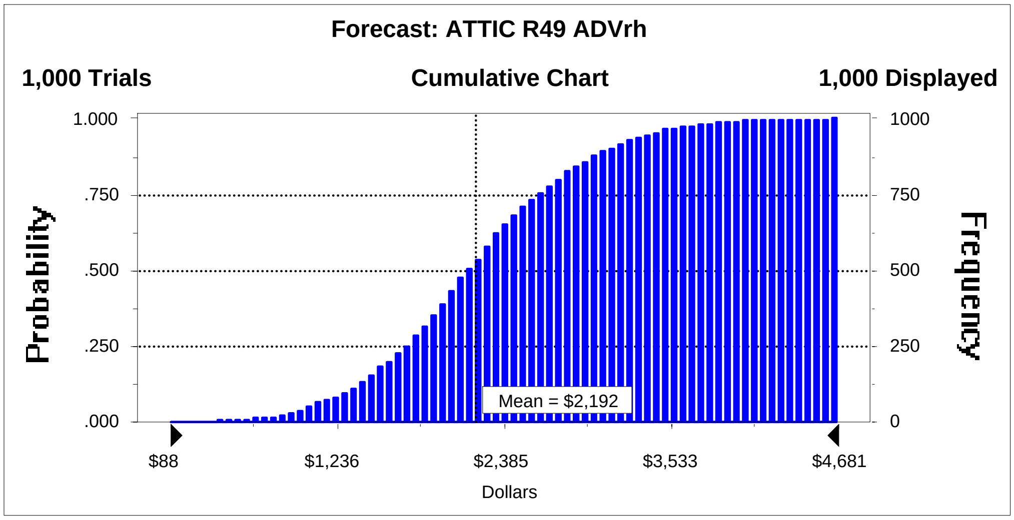


**Figure G-67: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Heat Pumps**

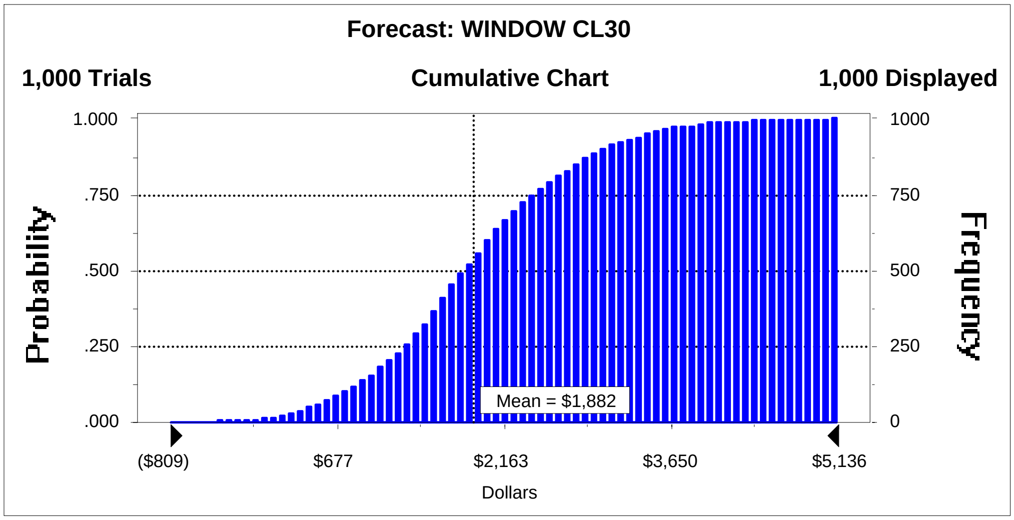


**Figure G-68: Climate Zone 2 Class 30 Window NPV Results for Heat Pumps**

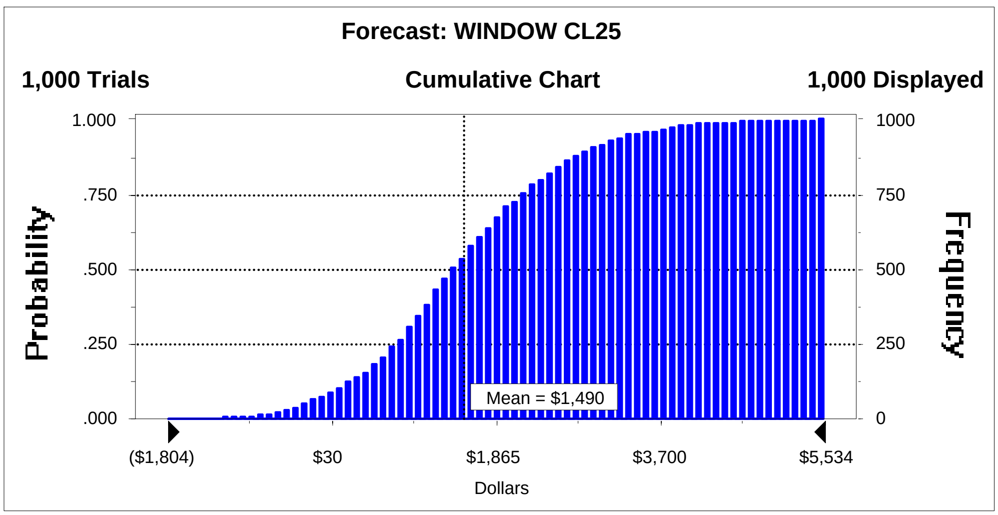


**Figure G-69: Climate Zone 2 Class 25 Window NPV Results for Heat Pumps**

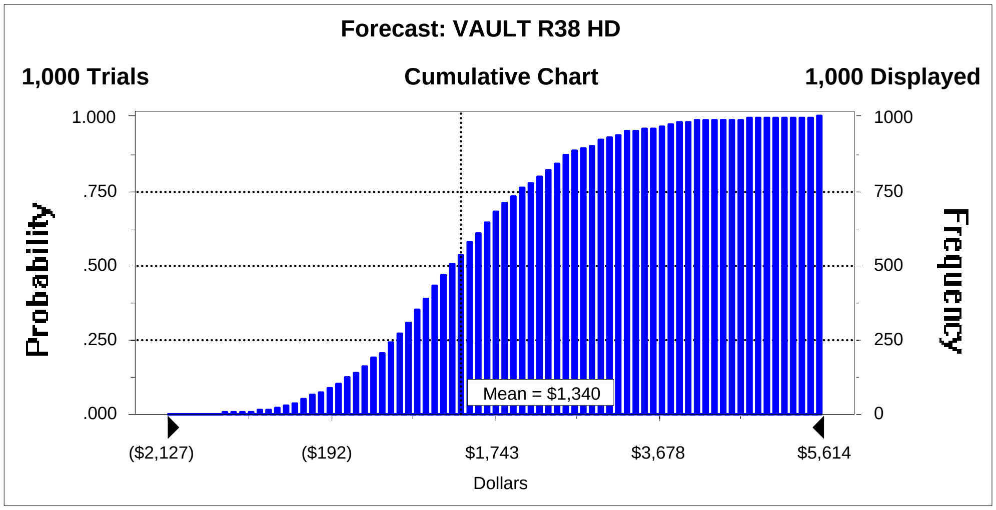


**Figure G-70: Climate Zone 2 R38 Vault NPV Results for Heat Pumps**

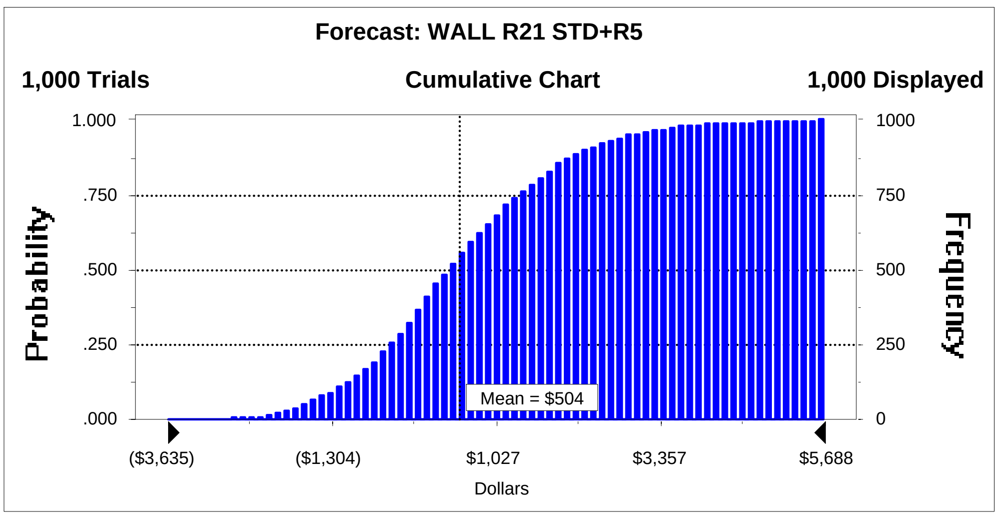


**Figure G-71: Climate Zone 2 R26 Advanced Framed Walls NPV Results for Heat Pumps**

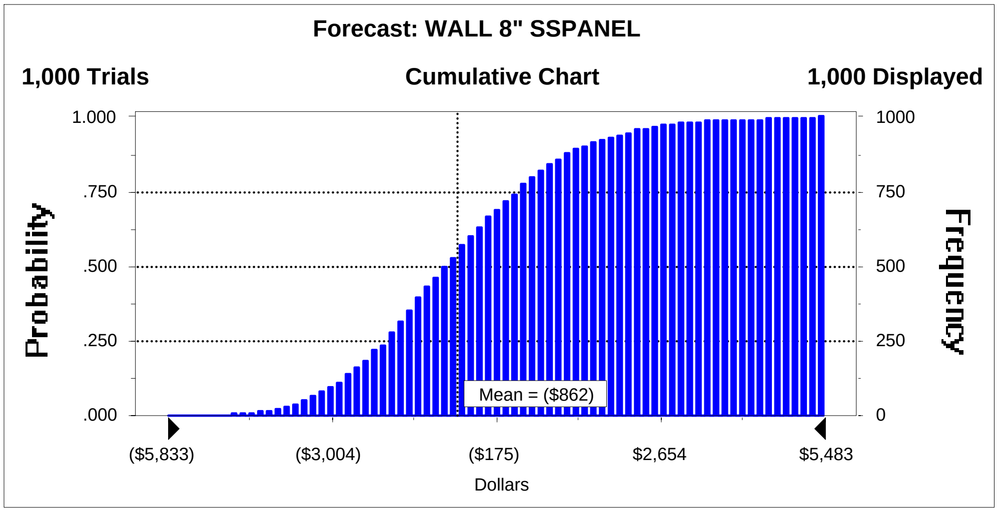


**Figure G-72: Climate Zone 2 R33 Wall NPV Results for Heat Pumps**

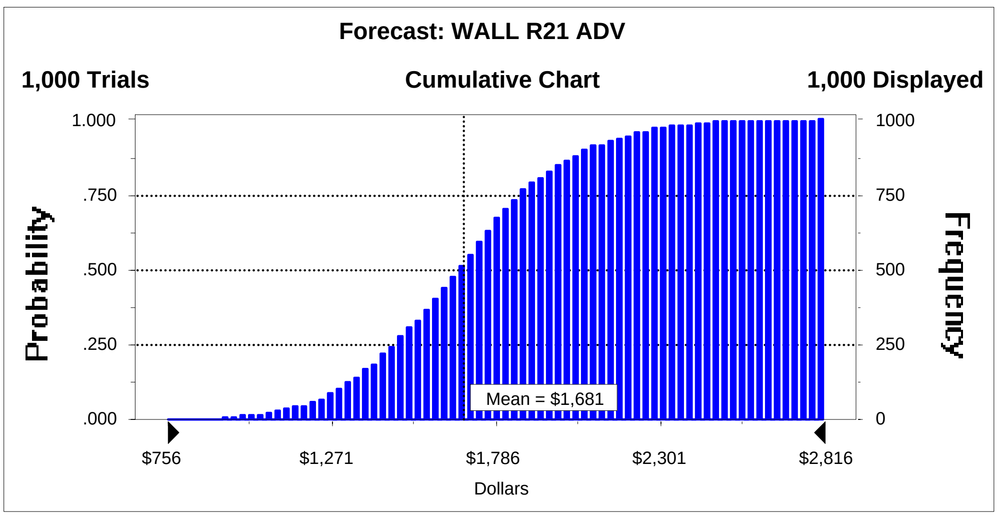


**Figure G-73: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric FAF**

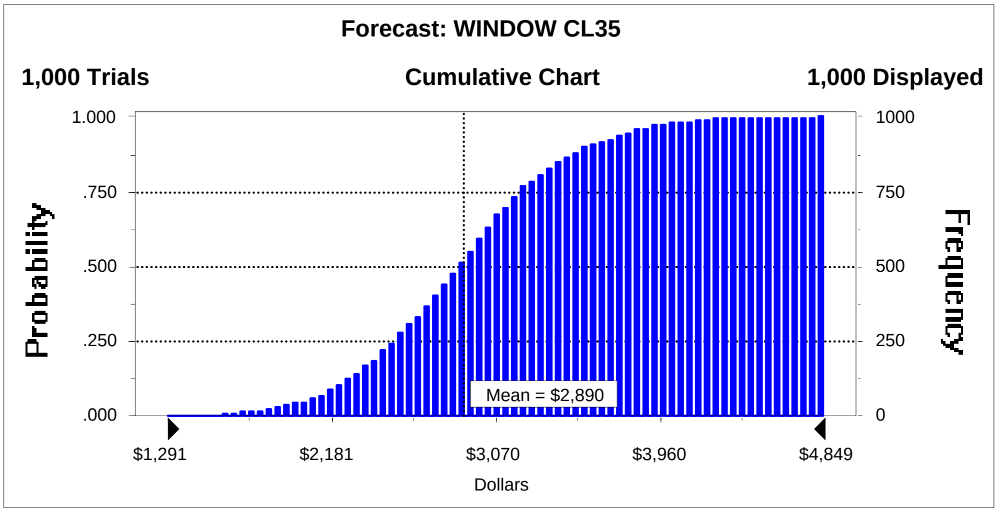


**Figure G-74: Climate Zone 2 Class 35 Windows NPV Results for Electric FAF**

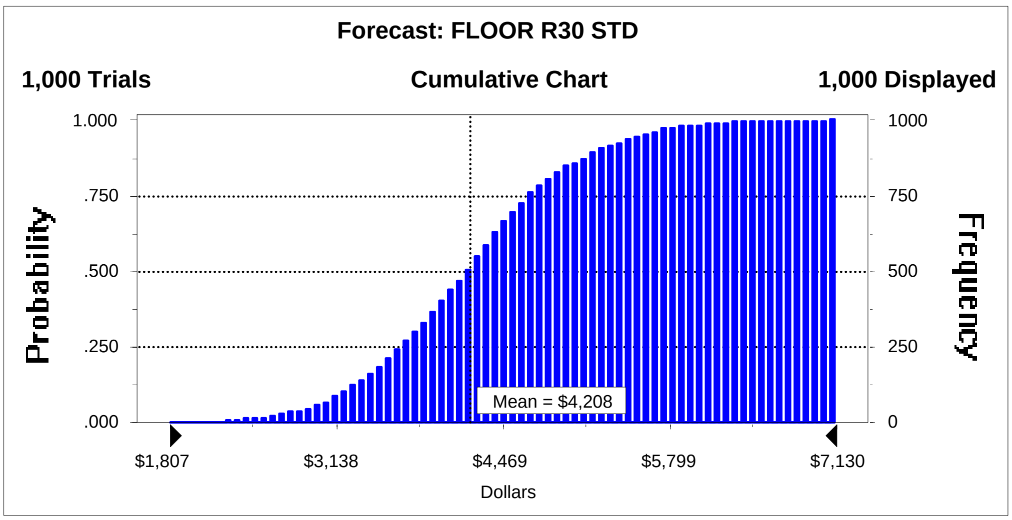


**Figure G-75: Climate Zone 2 R30 Under floor NPV Results for Electric FAF**

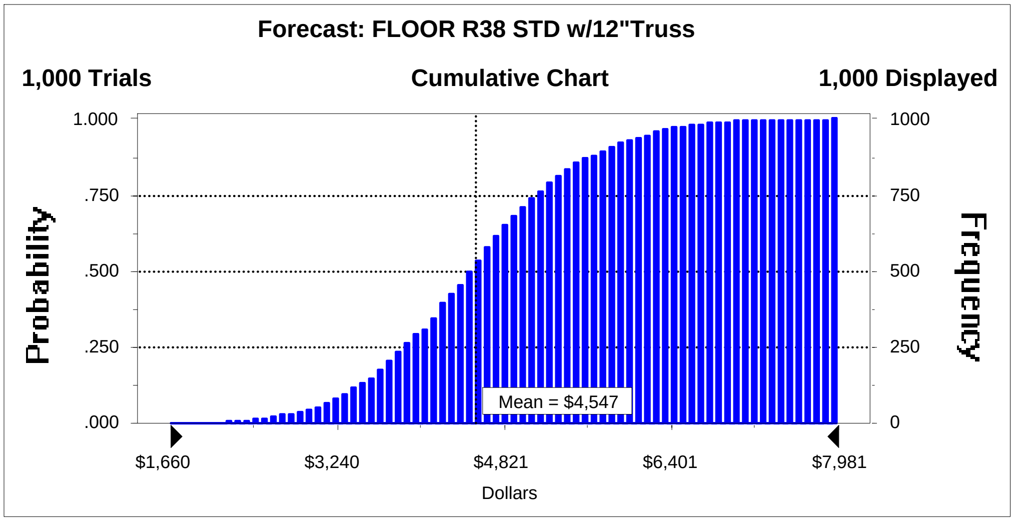


**Figure G-76: Climate Zone 2 R38 Under floor NPV Results for Electric FAF**

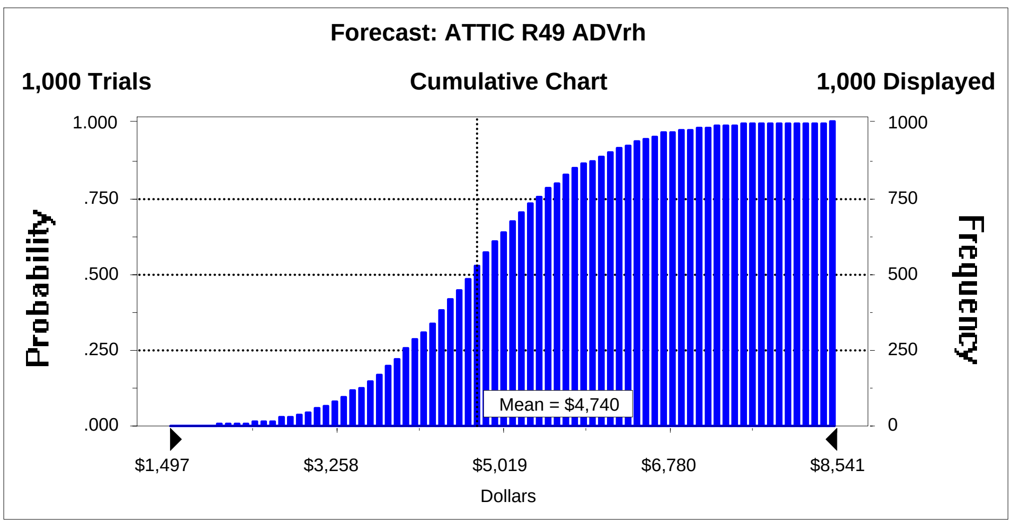


**Figure G-77: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric FAF**

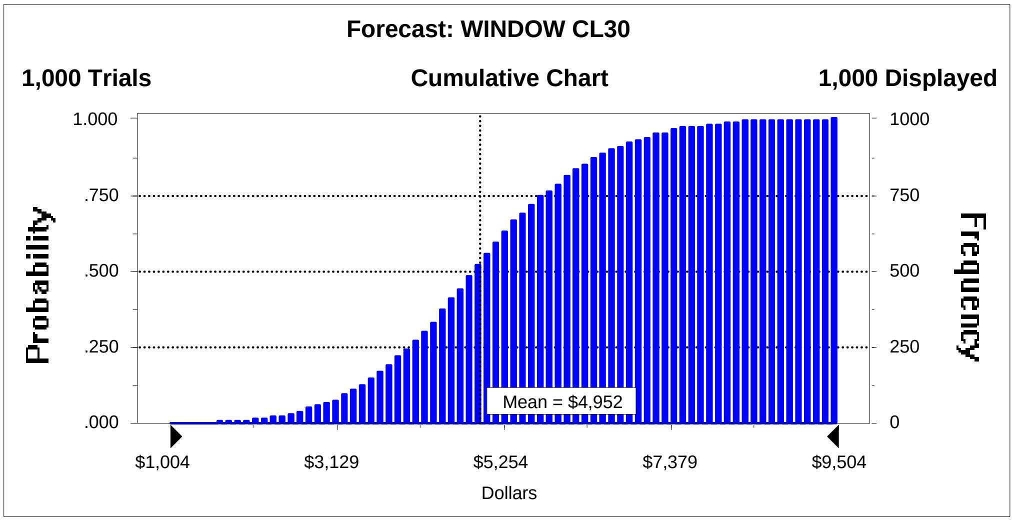


**Figure G-78: Climate Zone 2 Class 30 Window NPV Results for Electric FAF**

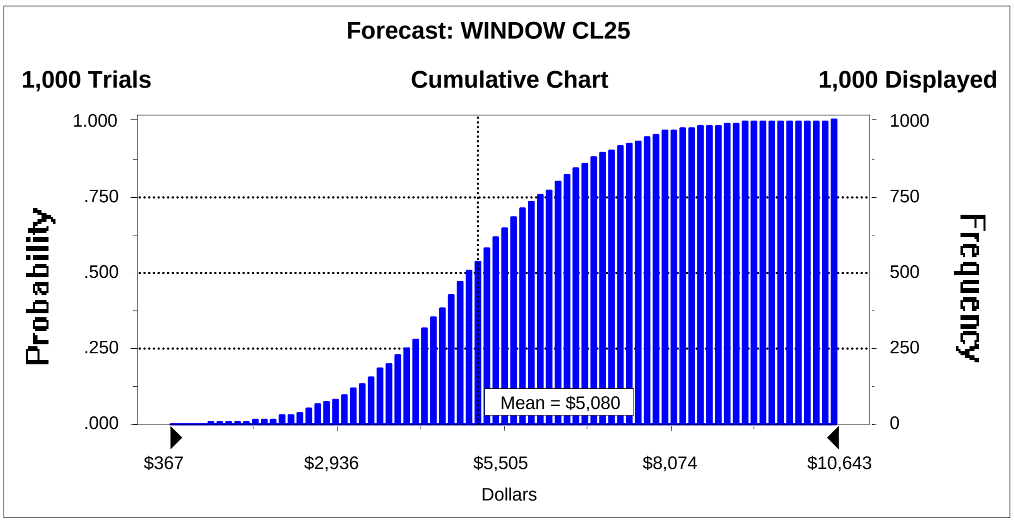


**Figure G-79: Climate Zone 2 Class 25 Window NPV Results for Electric FAF**

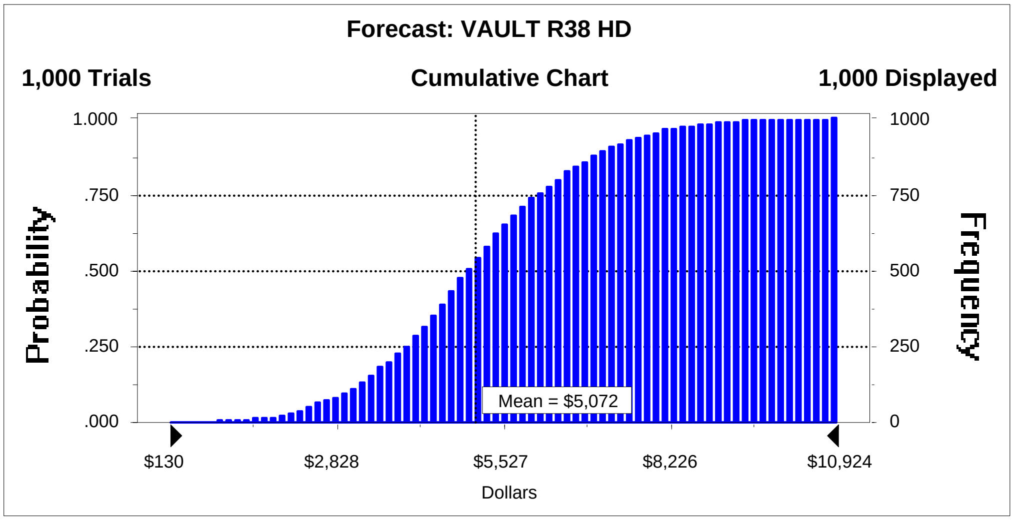


**Figure G-80: Climate Zone 2 R38 Vault NPV Results for Electric FAF**

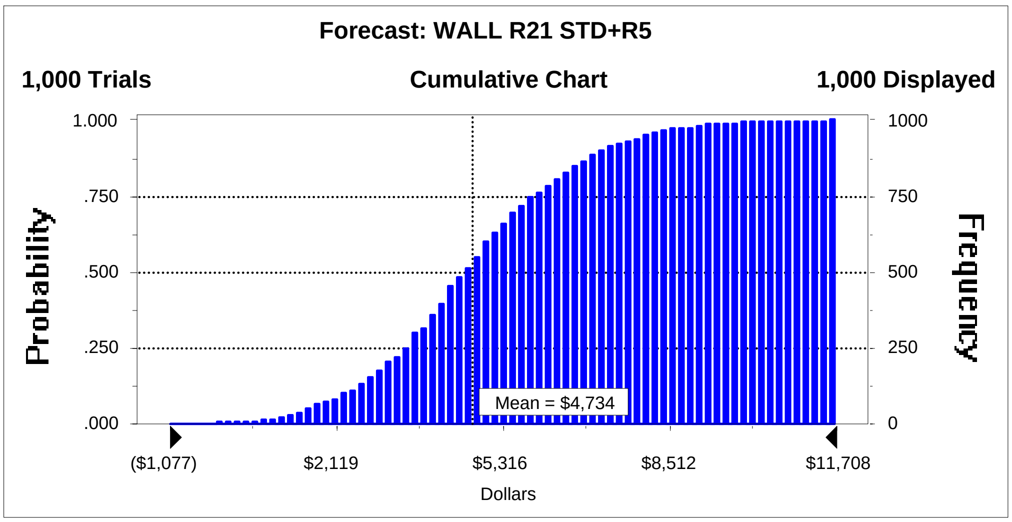


**Figure G-81: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric FAF**

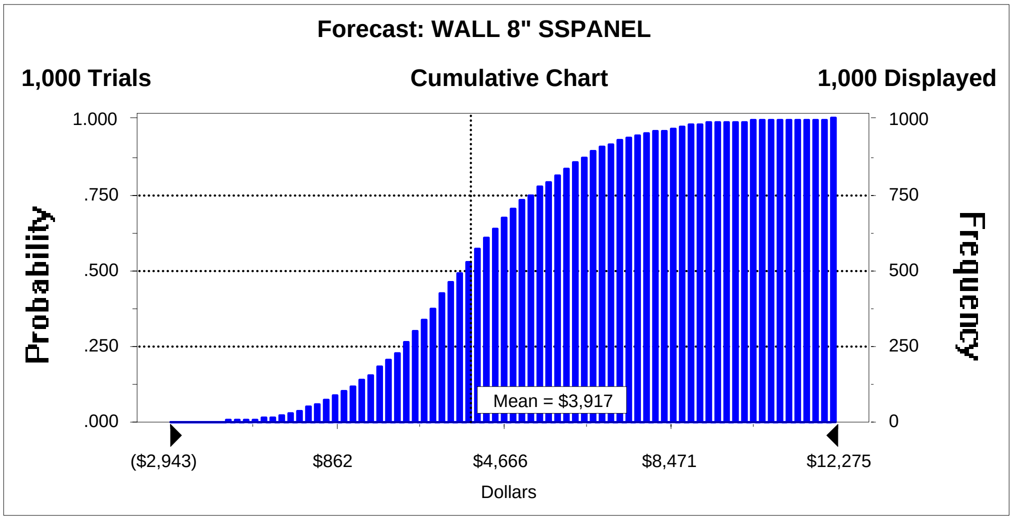


**Figure G-82: Climate Zone 2 R33 Wall NPV Results for Electric FAF**

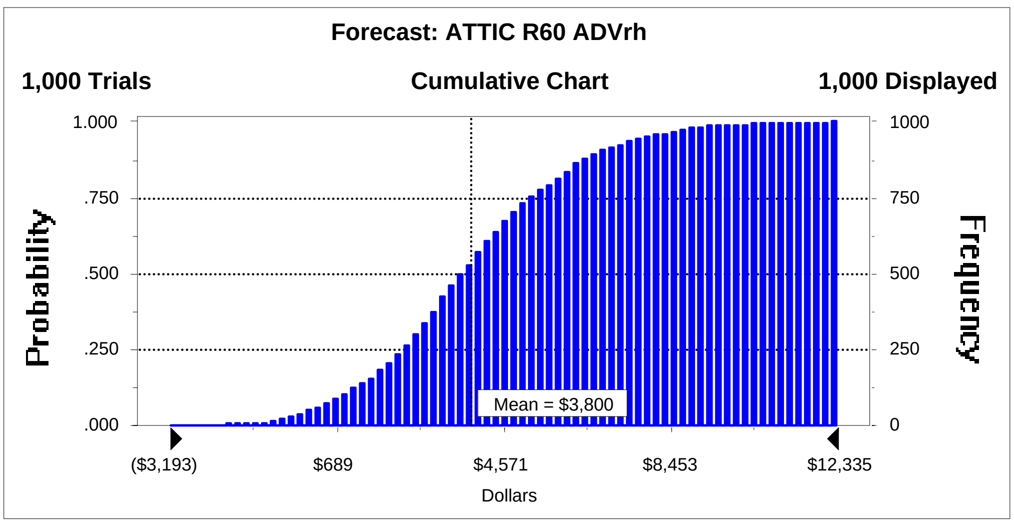


**Figure G-83: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric FAF**

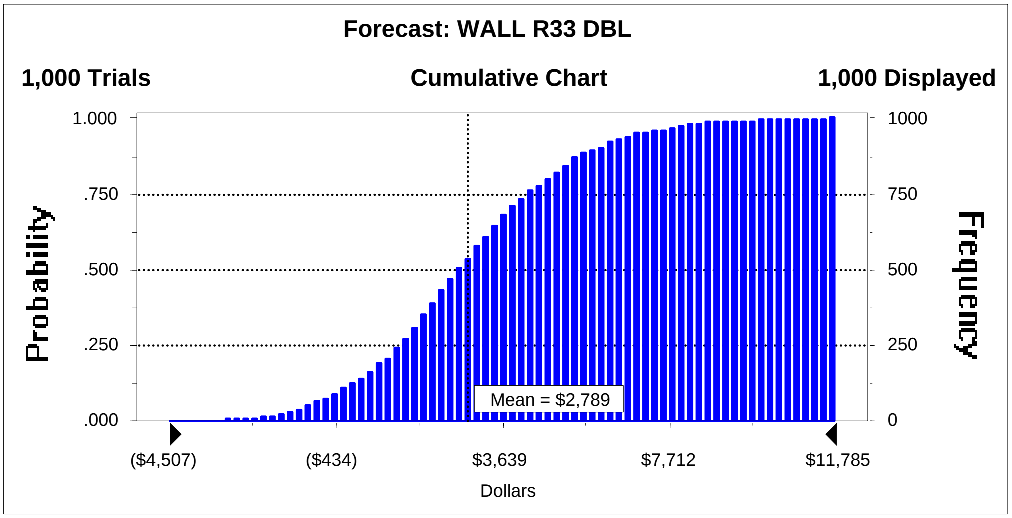


**Figure G-84: Climate Zone 2 R38 Wall NPV Results for Electric FAF**

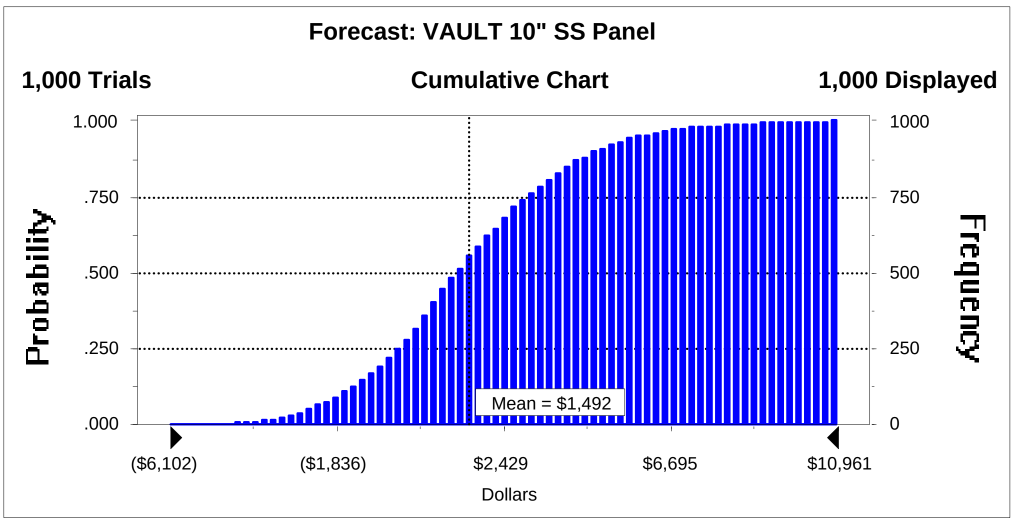


**Figure G-85: Climate Zone 2 R49 Vault NPV Results for Electric FAF**

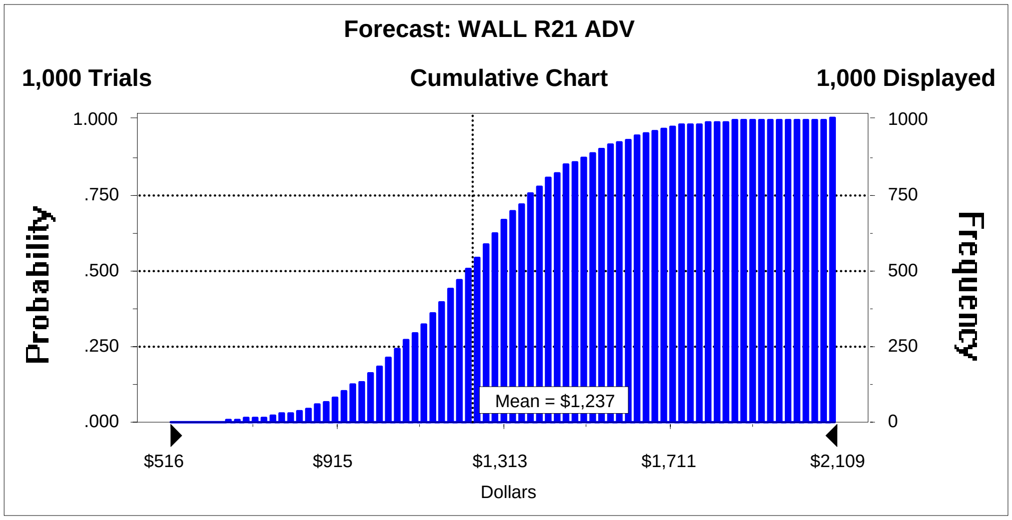


**Figure G-86: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric Zonal**

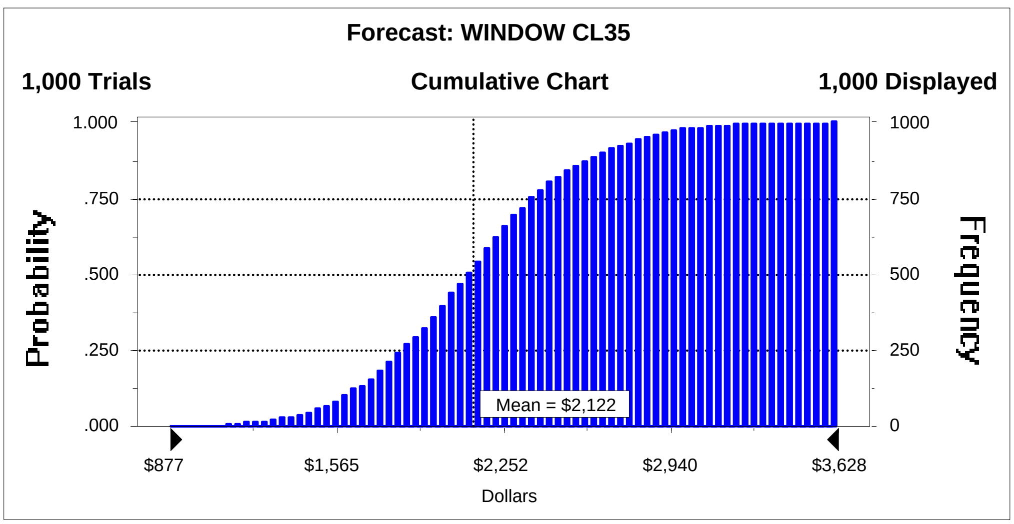


**Figure G-87: Climate Zone 2 Class 35 Window NPV Results for Electric Zonal**

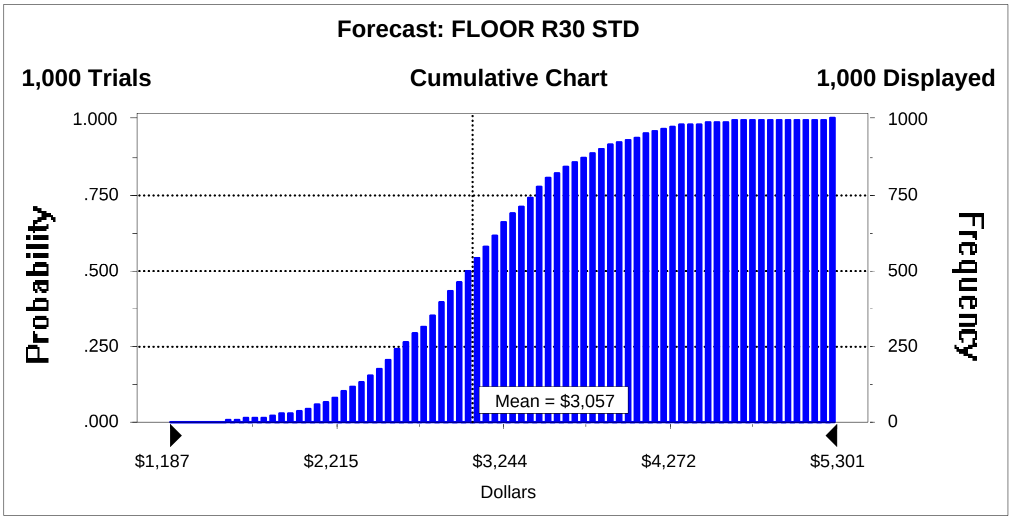


**Figure G-88: Climate Zone 2 R30 Under floor NPV Results for Electric Zonal**

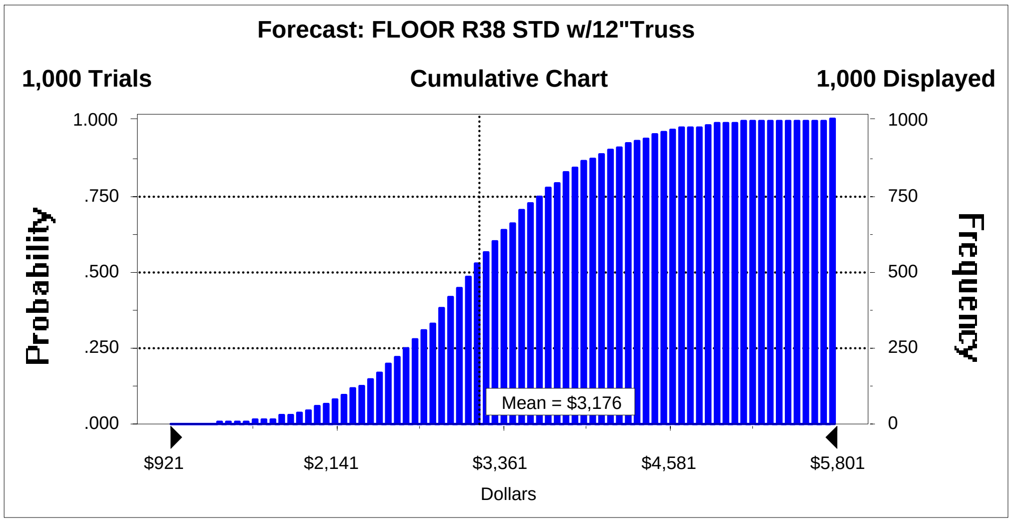


**Figure G-89: Climate Zone 2 R38 Under floor NPV Results for Electric Zonal**

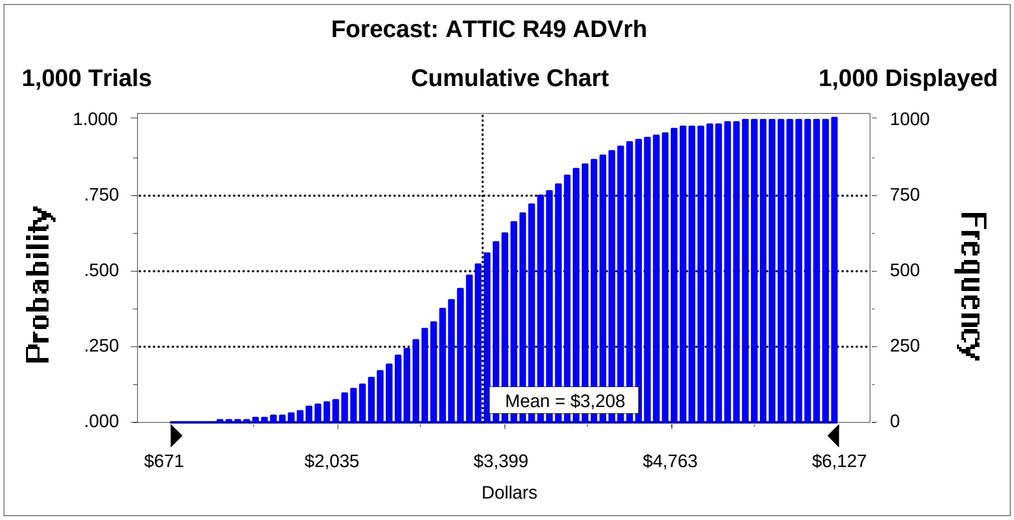


**Figure G-90: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric Zonal**

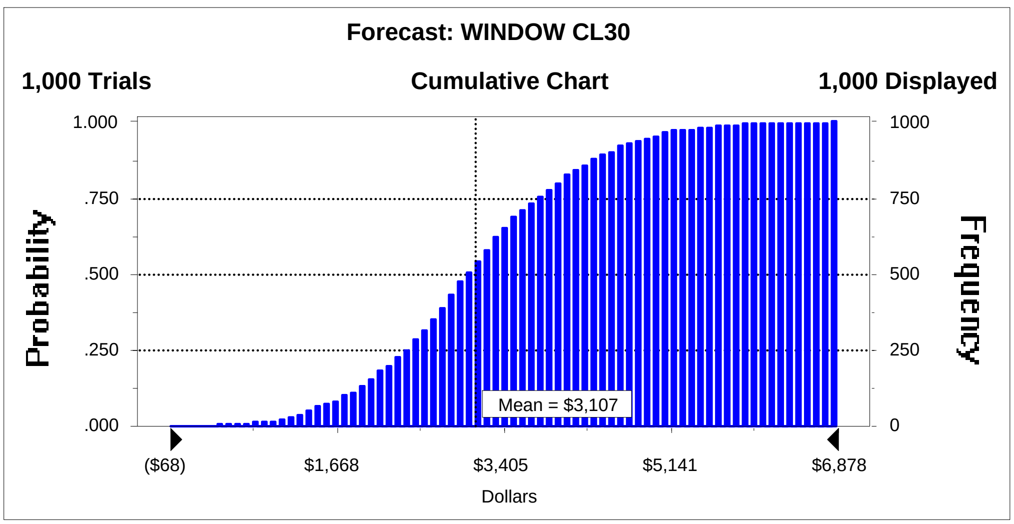


**Figure G-91: Climate Zone 2 Class 30 Window NPV Results for Electric Zonal**

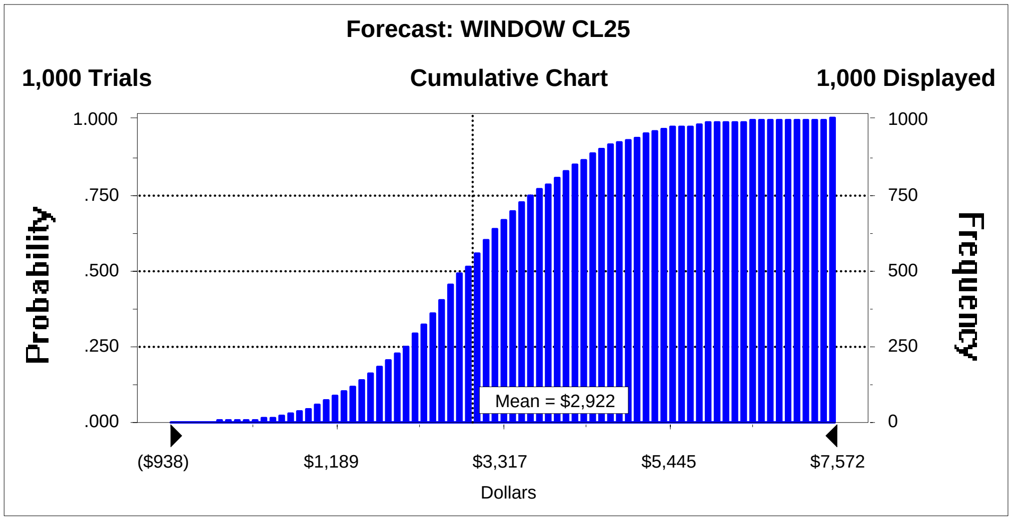


**Figure G-92: Climate Zone 2 Class 25 Window NPV Results for Electric Zonal**

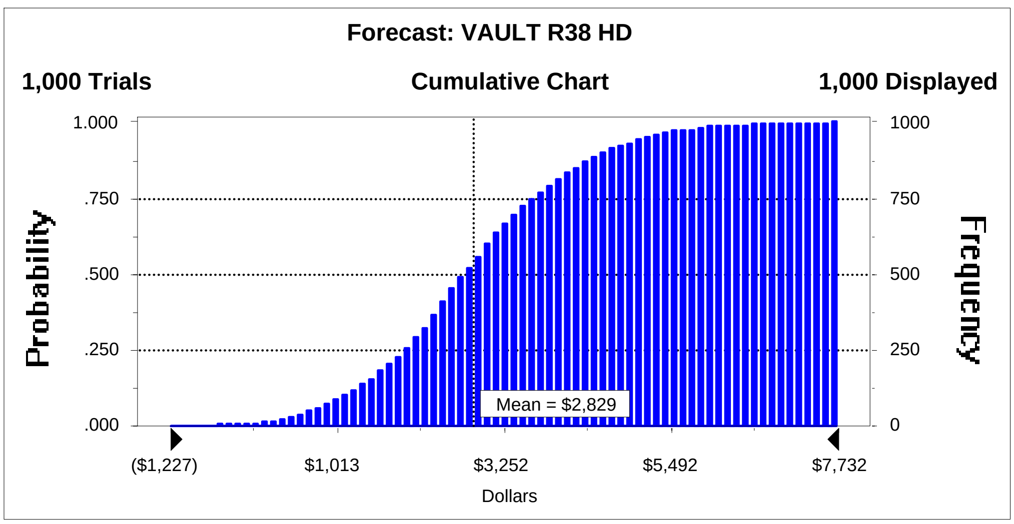


**Figure G-93: Climate Zone 2 R38 Vault NPV Results for Electric Zonal**

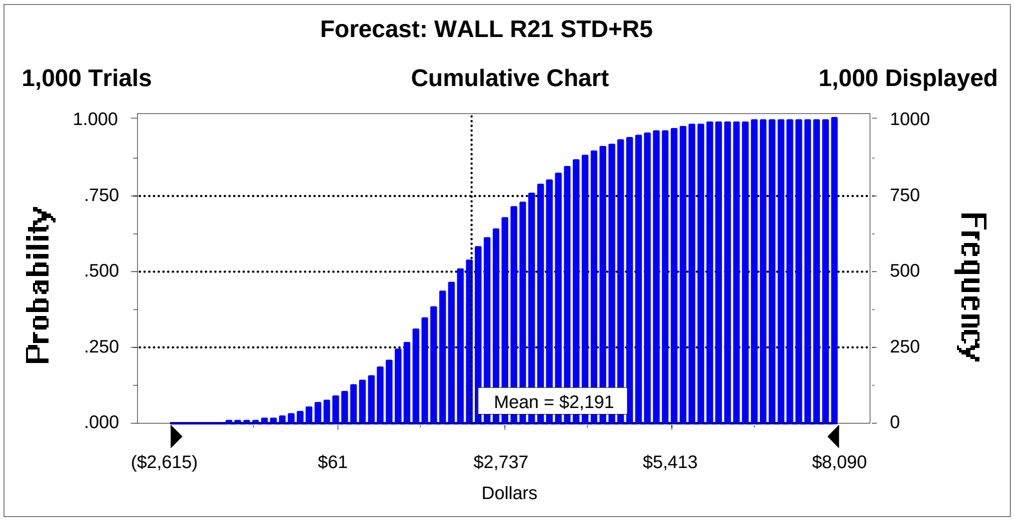


**Figure G-94: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric Zonal**

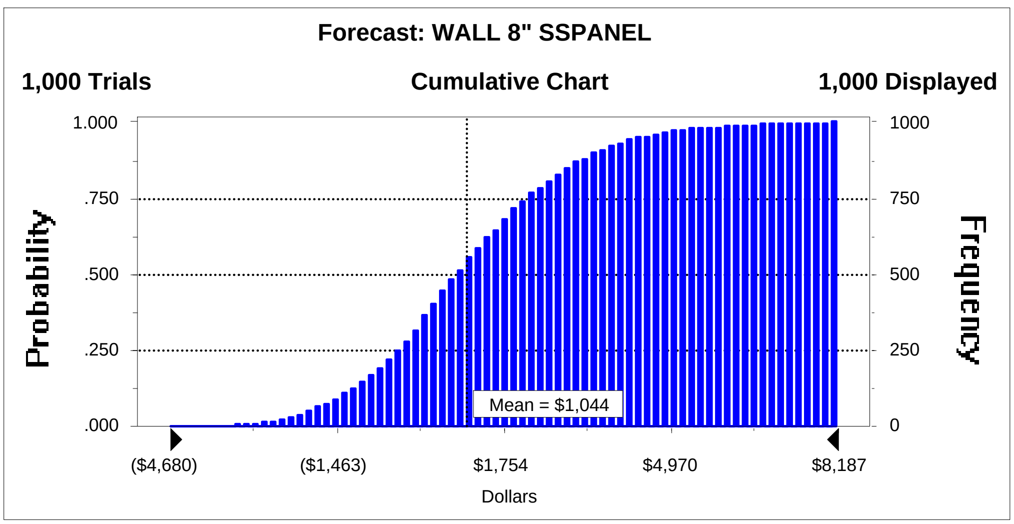


**Figure G-95: Climate Zone 2 R33 Wall NPV Results for Electric Zonal**

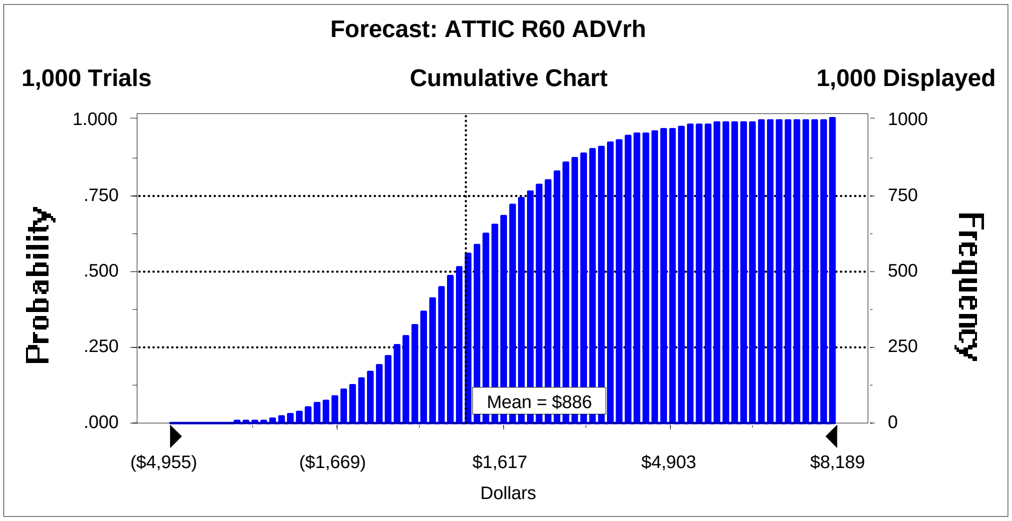


**Figure G-96: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric Zonal**

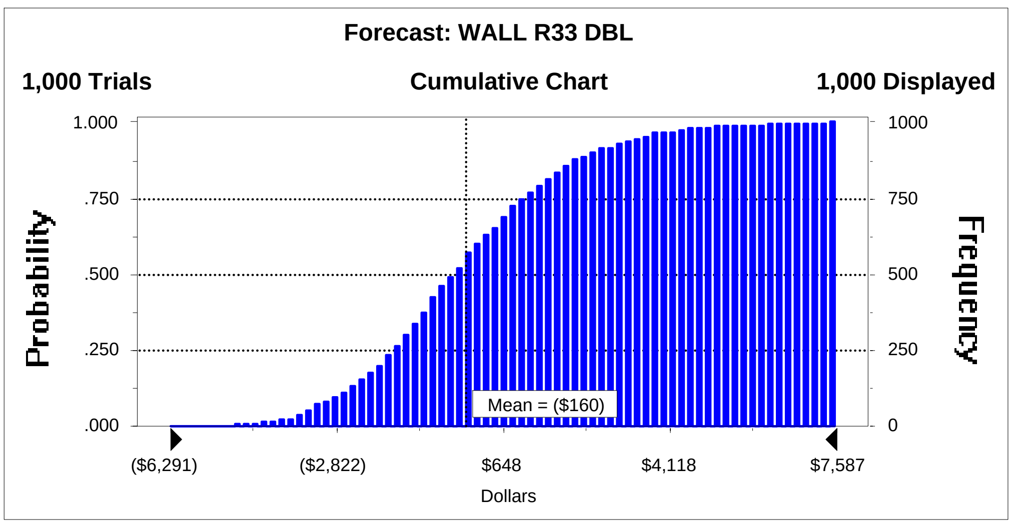


**Figure G-97: Climate Zone 2 R33 Wall NPV Results for Electric Zonal**

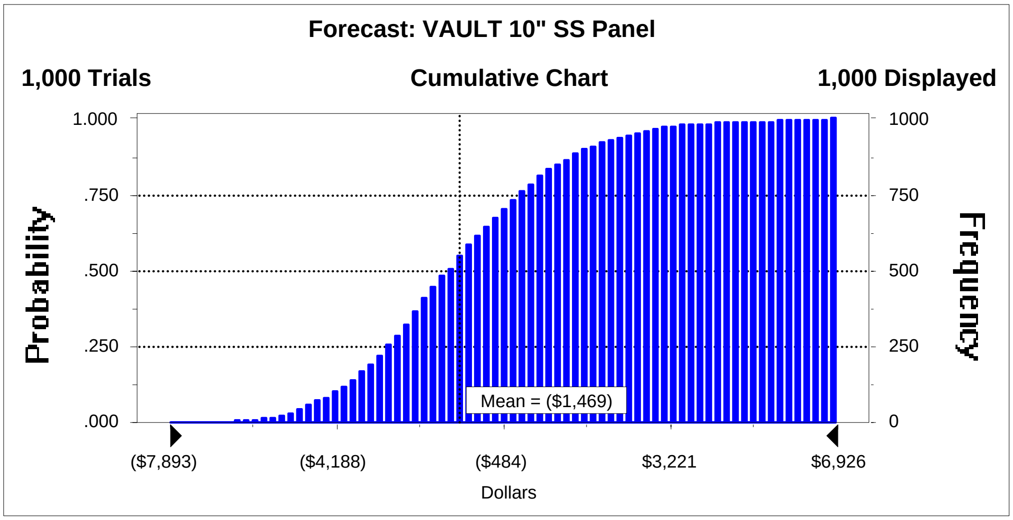


**Figure G-98: Climate Zone 2 R49 Vault NPV Results for Electric Zonal**

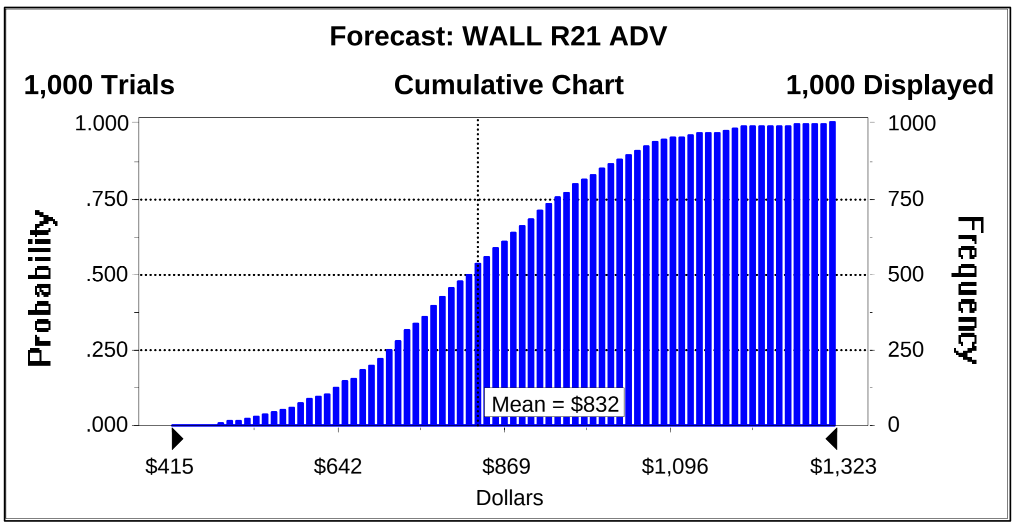


**Figure G-99: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Gas FAF**

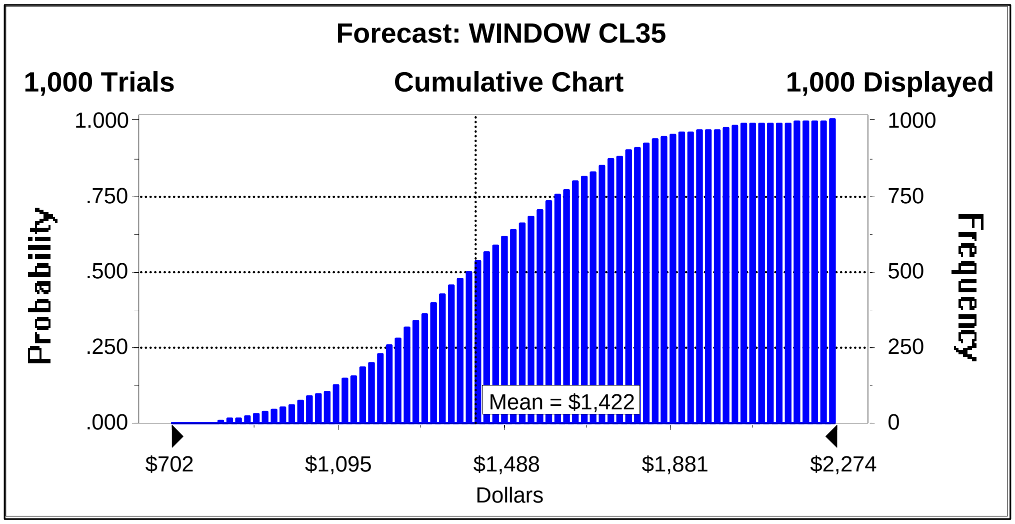


**Figure G-100: Climate Zone 2 Class 35 Windows NPV Results for Gas FAF**

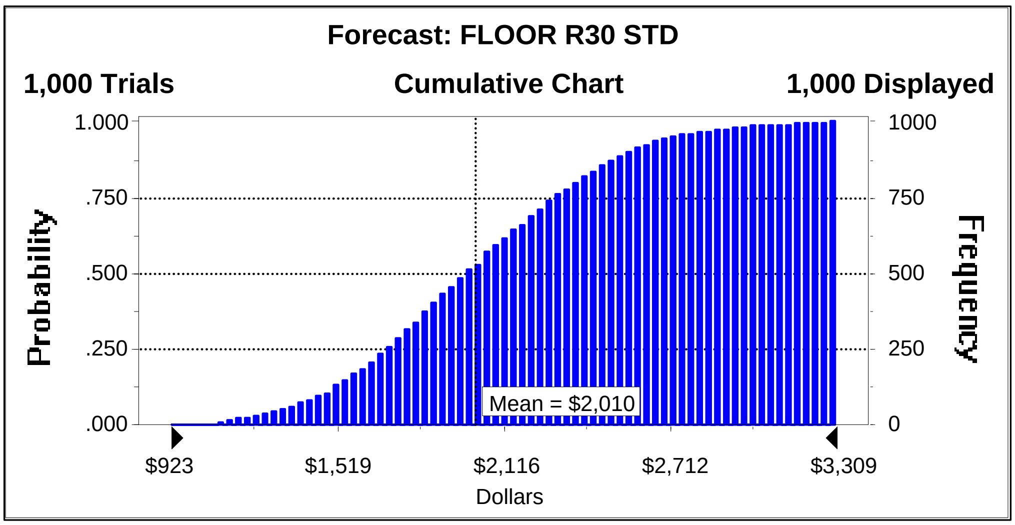


**Figure G-101: Climate Zone 2 R30 Under floor NPV Results for Gas FAF**

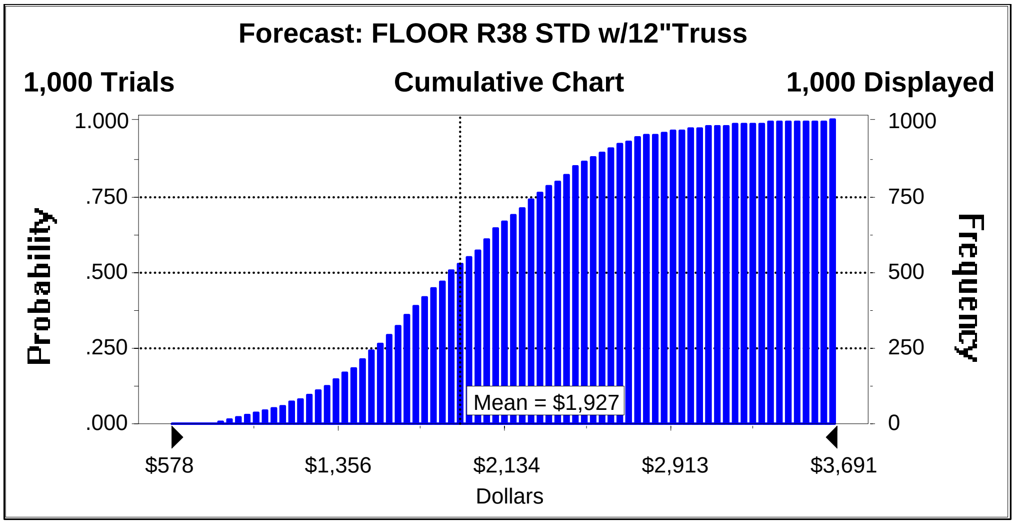


**Figure G-102: Climate Zone 2 R38 Under floor NPV Results for Gas FAF**

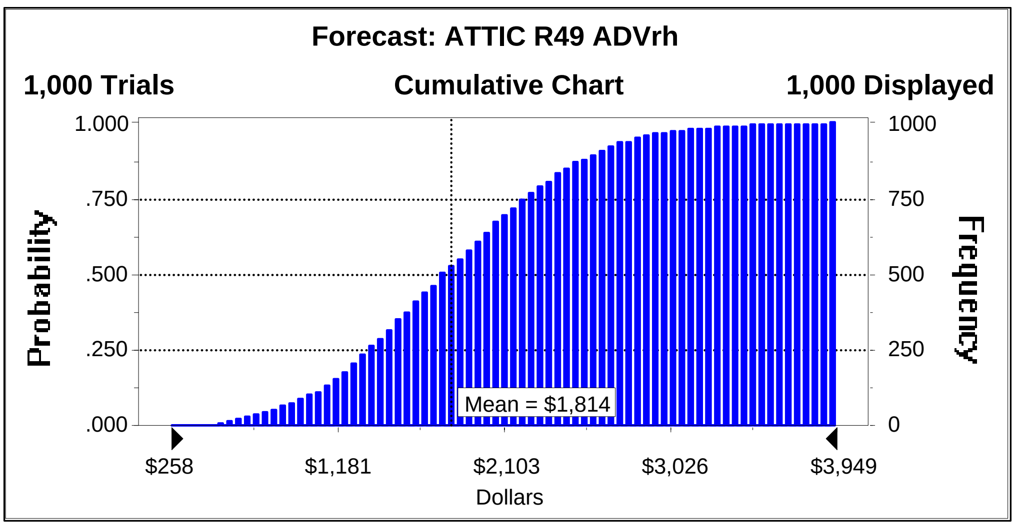


**Figure G-103: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Gas FAF**

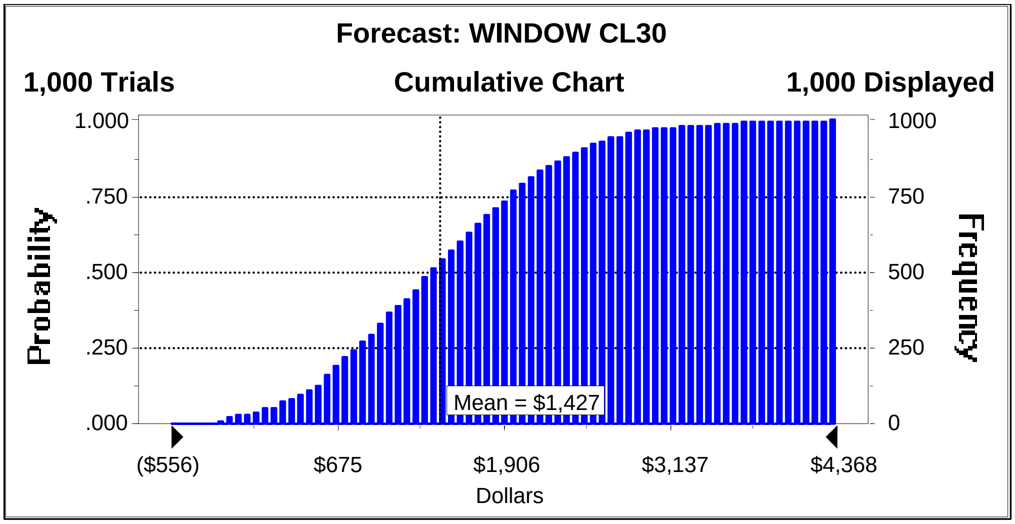


**Figure G-104: Climate Zone 2 Class 30 Window NPV Results for Gas FAF**

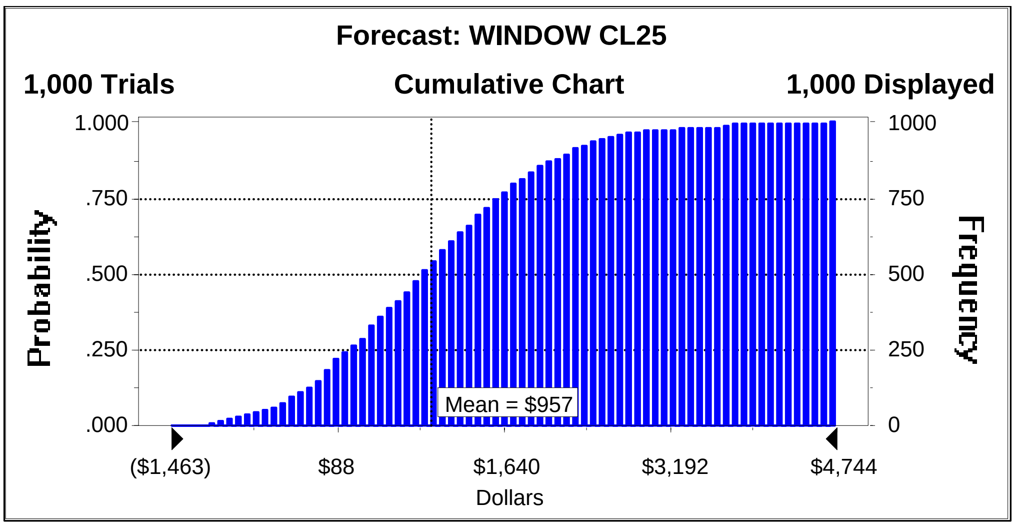


**Figure G-105: Climate Zone 2 Class 25 Window NPV Results for Gas FAF**

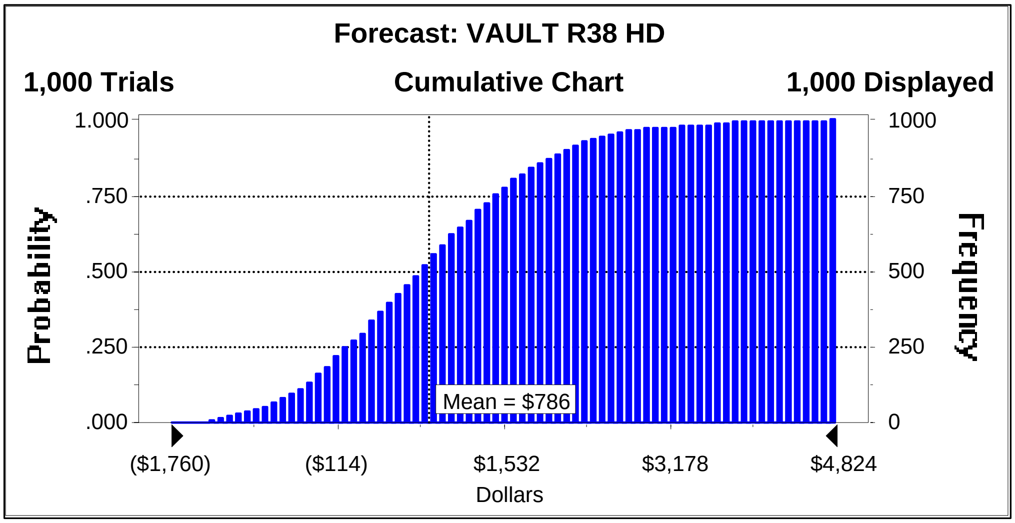


**Figure G-106: Climate Zone 2 R38 Vault NPV Results for Gas FAF**

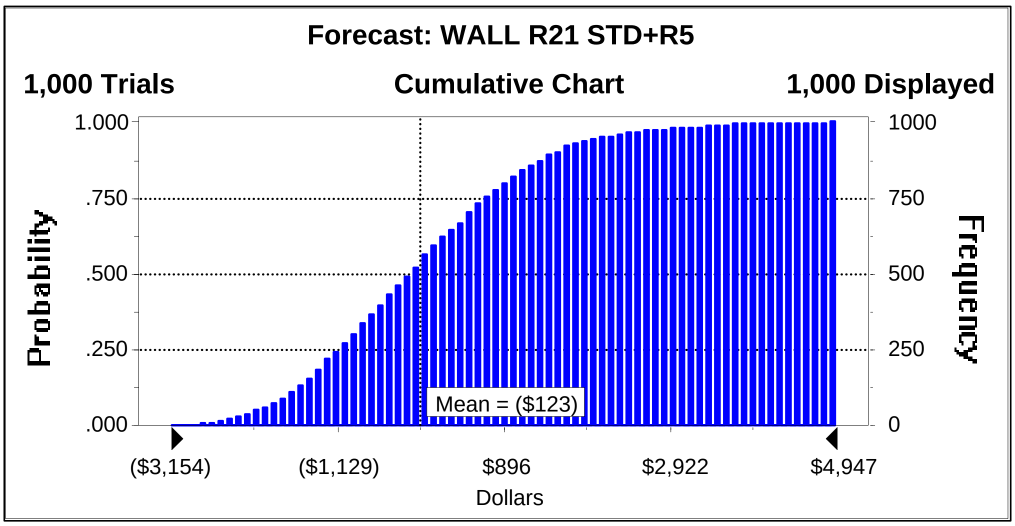


**Figure G-107: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Gas FAF**

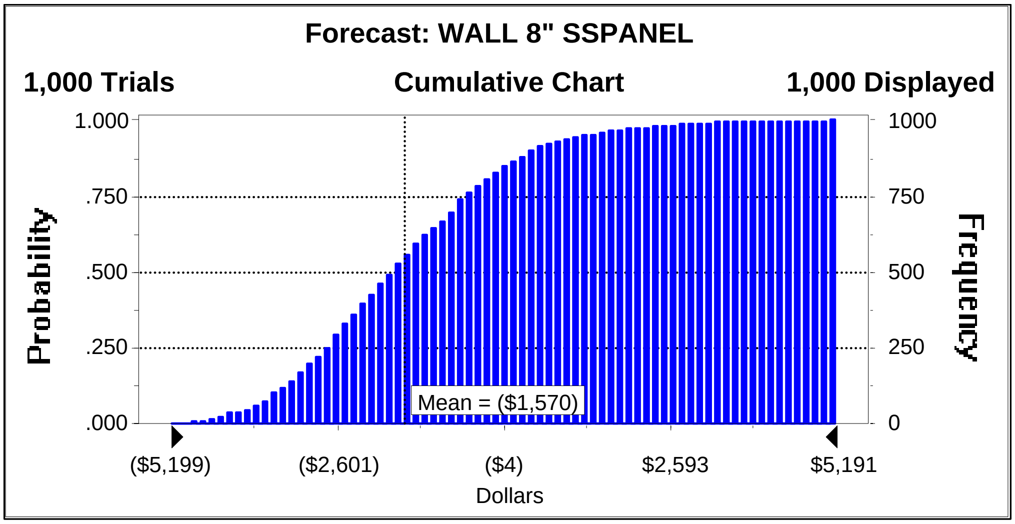


**Figure G-108: Climate Zone 2 R33 Wall NPV Results for Gas FAF**

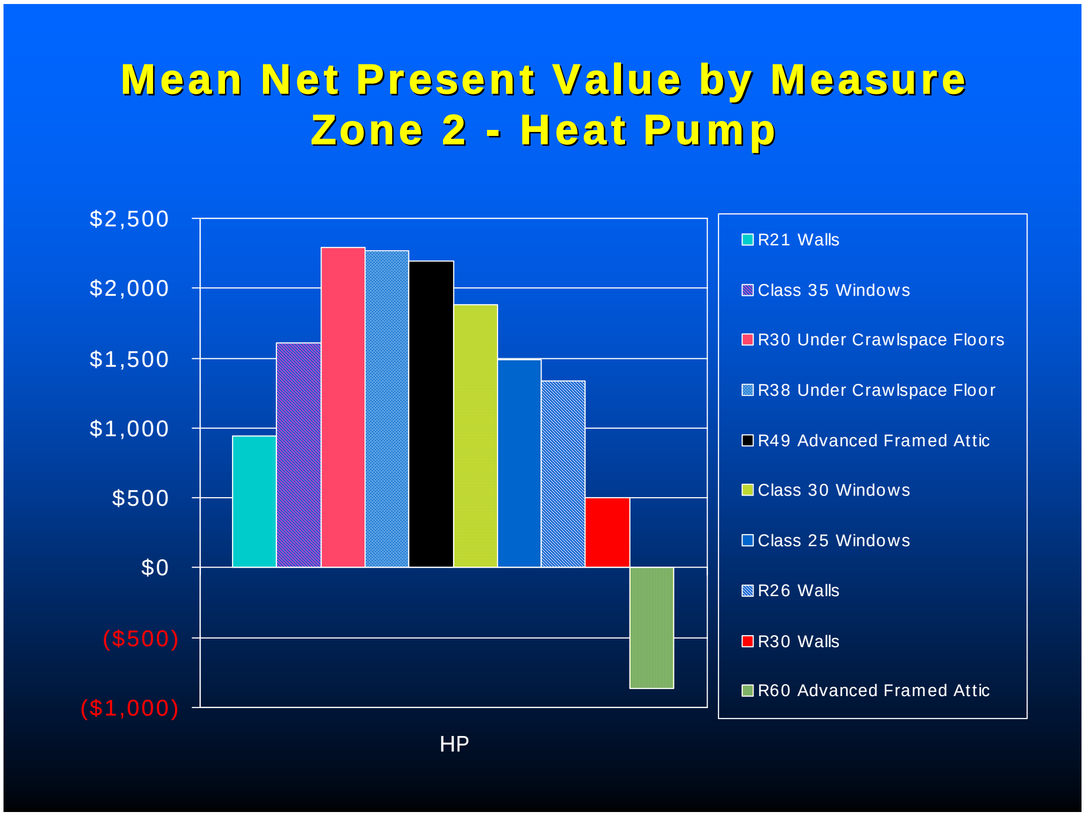


**Figure G-109: Climate Zone 2 Summary of Mean NPV by Measure for Heat Pumps**

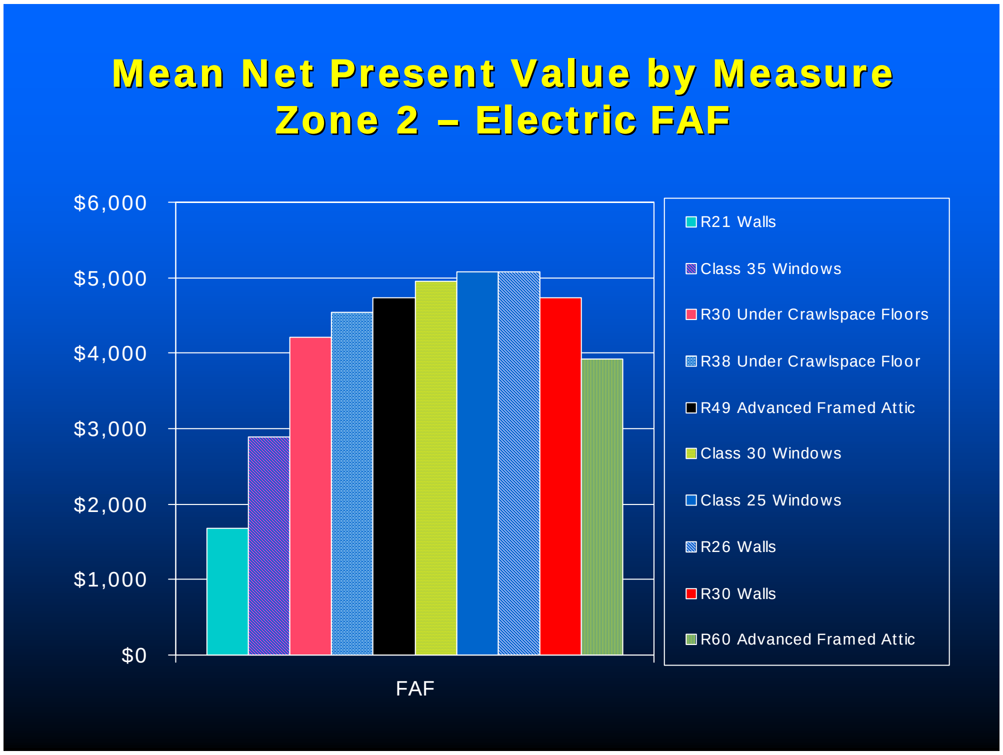


**Figure G-110: Climate Zone 2 Mean NPV by Measure for Electric FAF**

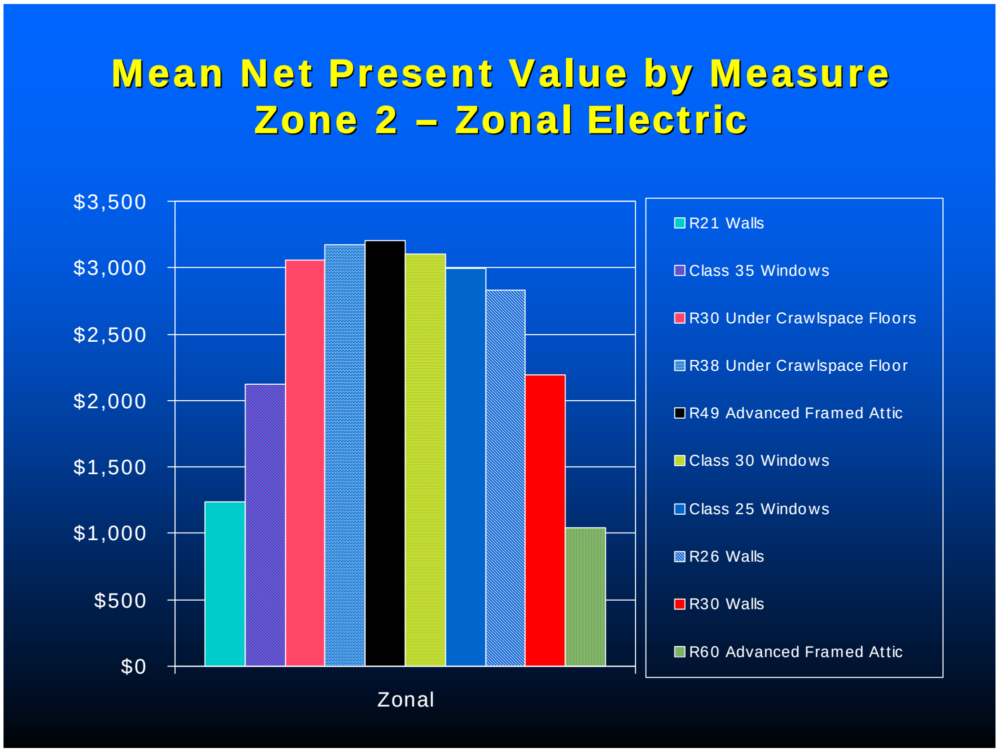


**Figure G-111: Climate Zone 2 Mean NPV by Measure for Electric Zonal**

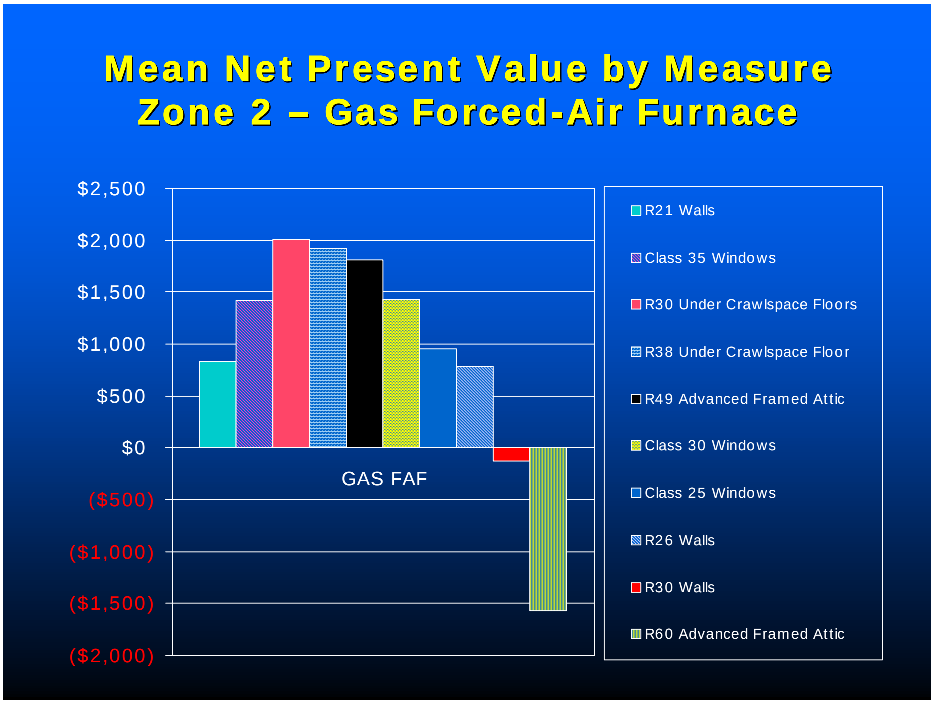


**Figure G-112: Climate Zone 2 Mean NPV by Measure for Gas FAF**

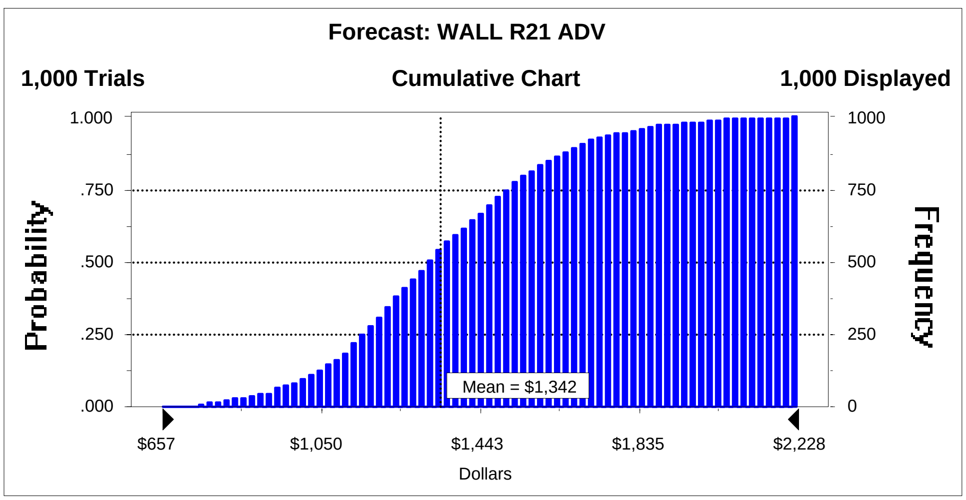


**Figure G-113: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Heat Pumps**

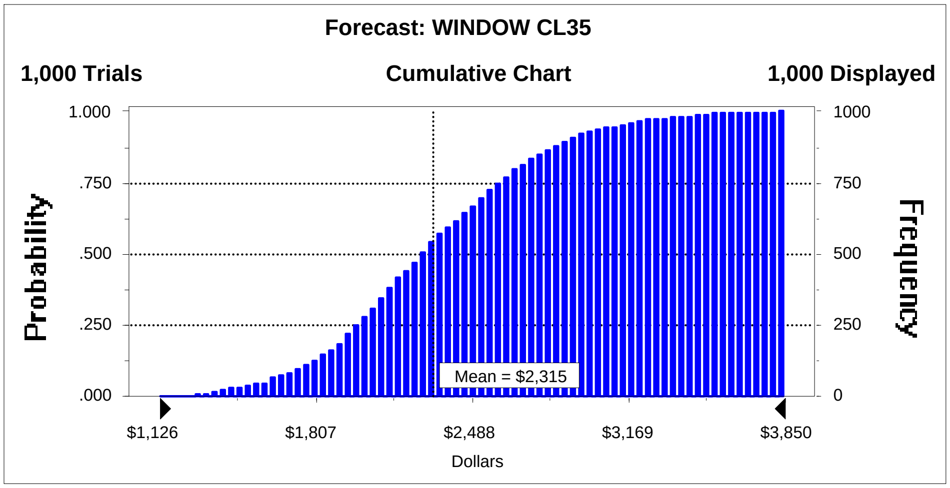


**Figure G-114: Climate Zone 3 Class 35 Window NPV Results for Heat Pumps**

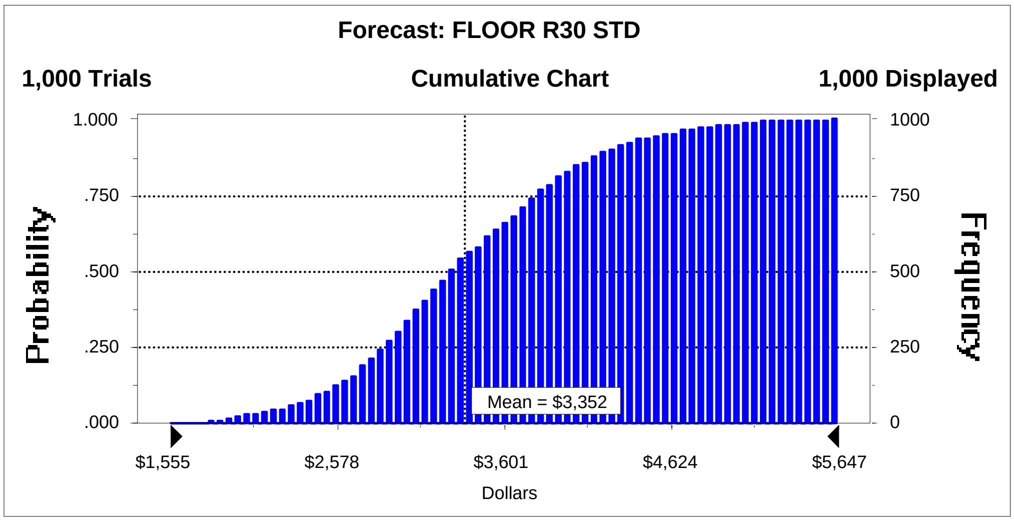


**Figure G-115: Climate Zone 3 R30 Under floor NPV Results for Heat Pumps**

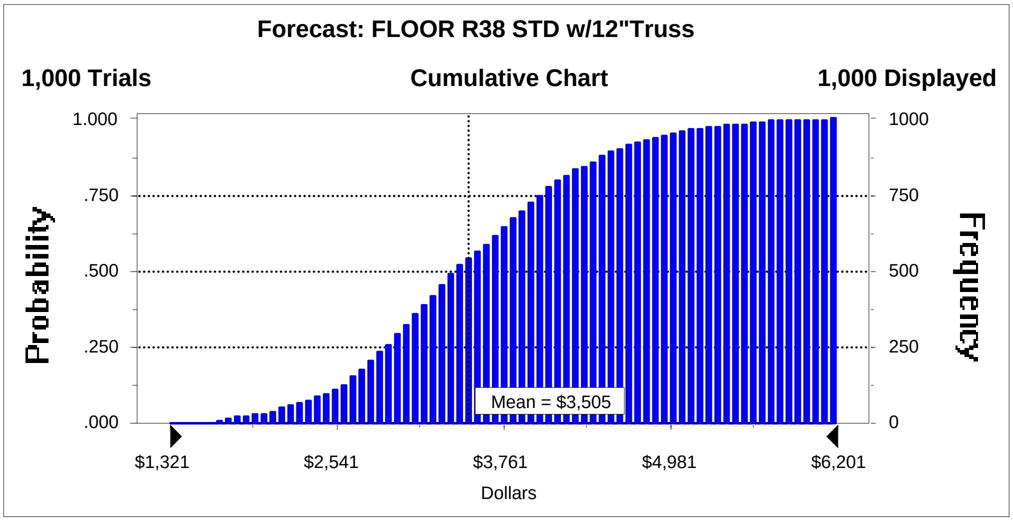


**Figure G-116: Climate Zone 3 R38 Under floor NPV Results for Heat Pumps**

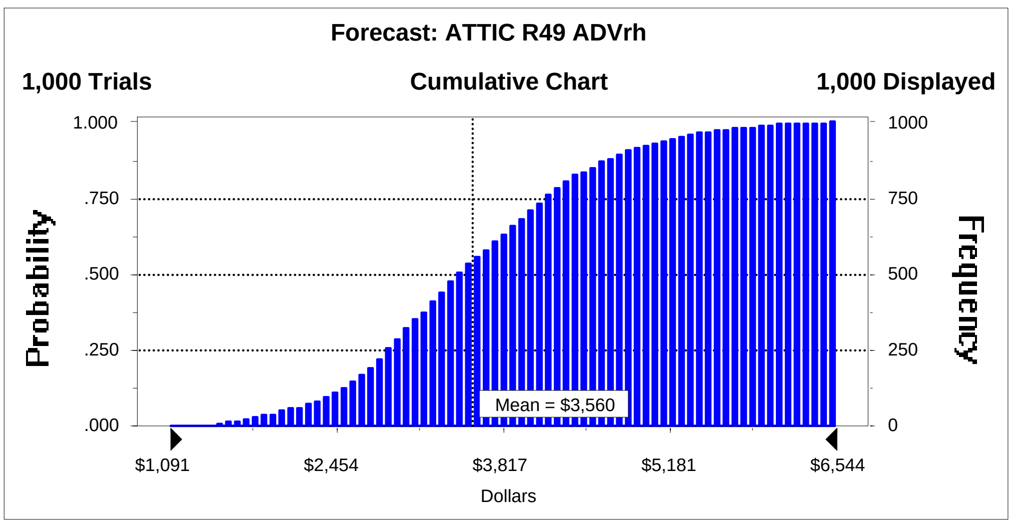


**Figure G-117: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Heat Pumps**

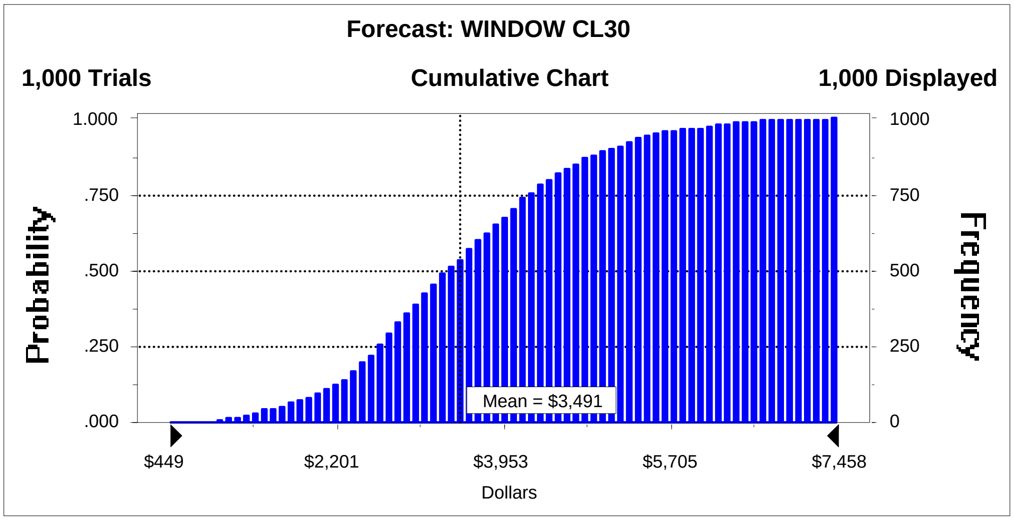


**Figure G-118: Climate Zone 3 Class 30 Window NPV Results for Heat Pumps**

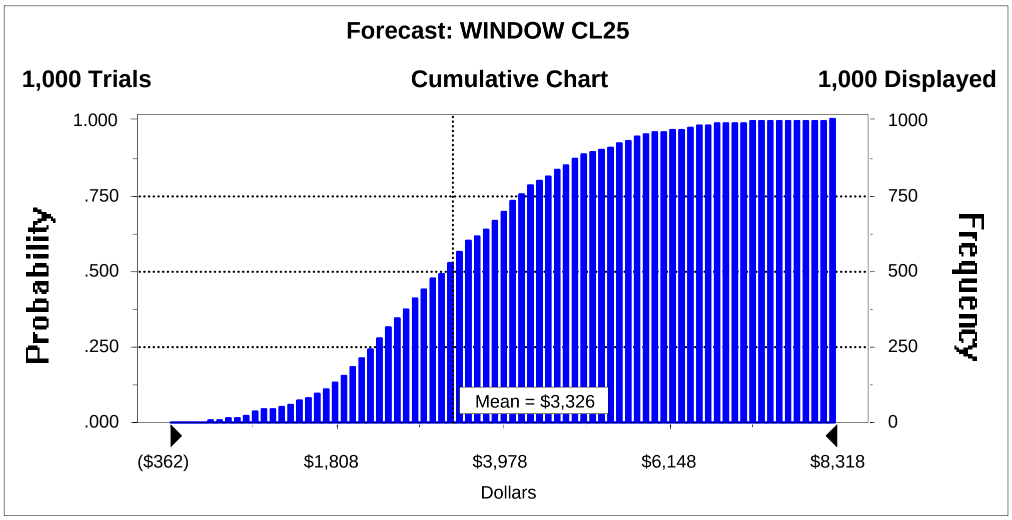


**Figure G-119: Climate Zone 3 Class 25 Window NPV Results for Heat Pumps**

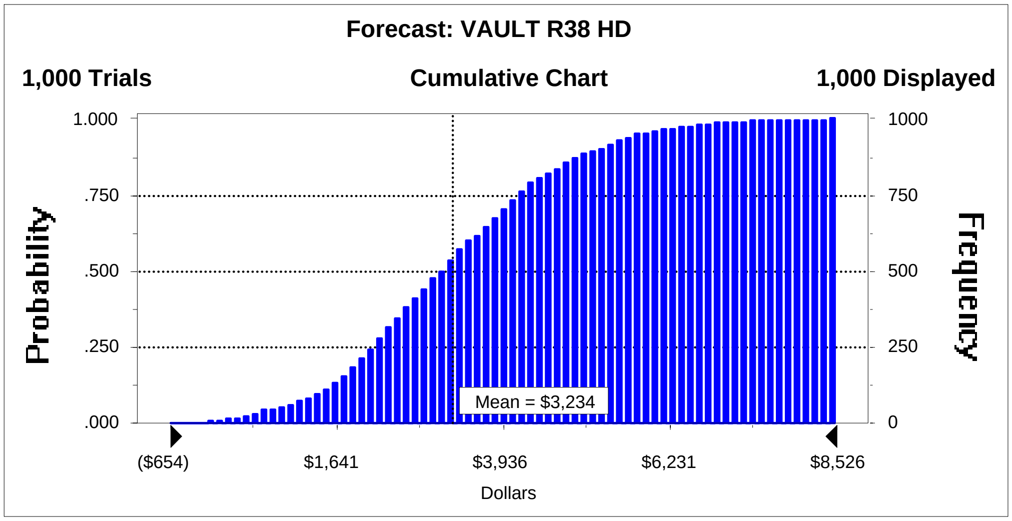


**Figure G-120: Climate Zone 3 R38 Vault NPV Results for Heat Pumps**

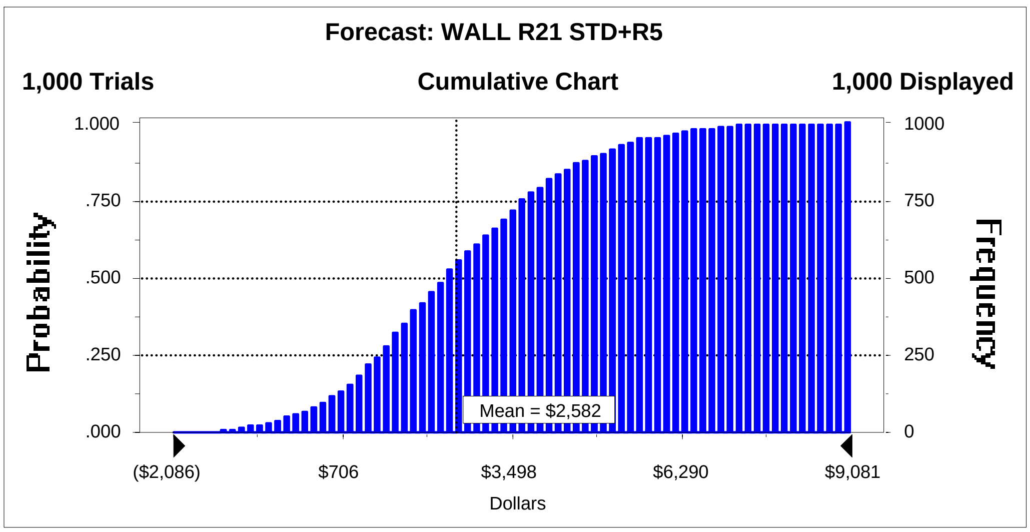


**Figure G-121: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Heat Pumps**

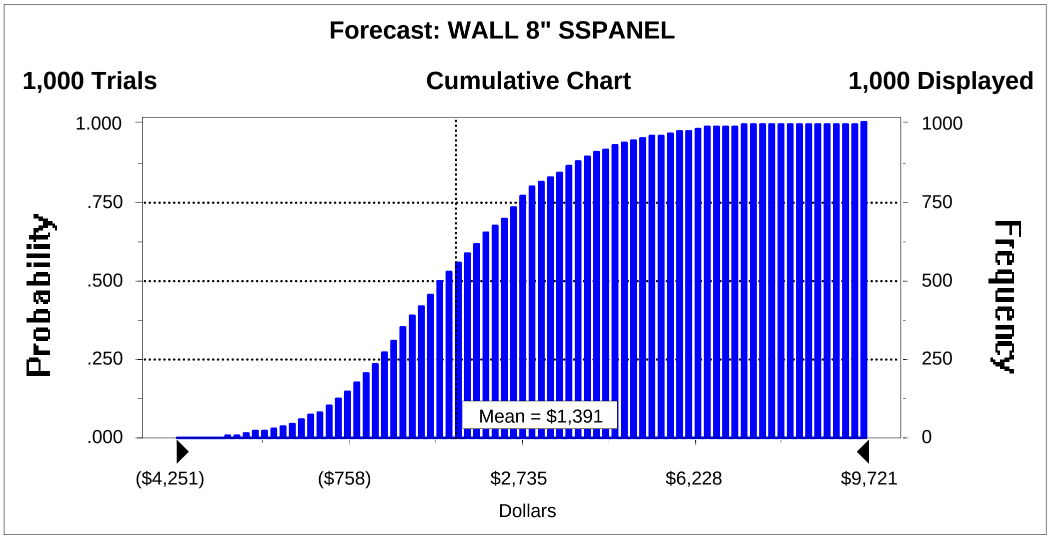


**Figure G-122: Climate Zone 3 R33 Wall NPV Results for Heat Pumps**

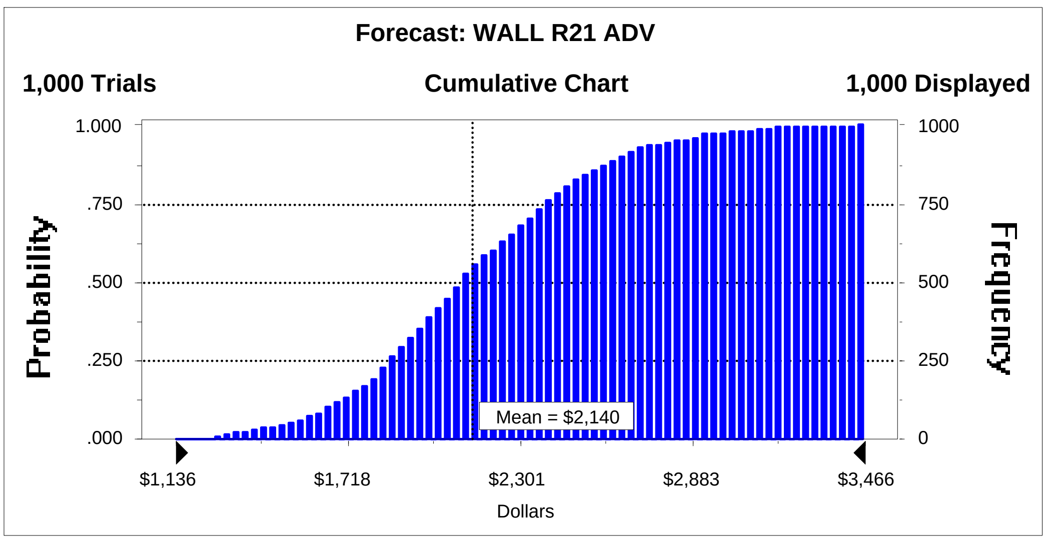


**Figure G-123: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric FAF**

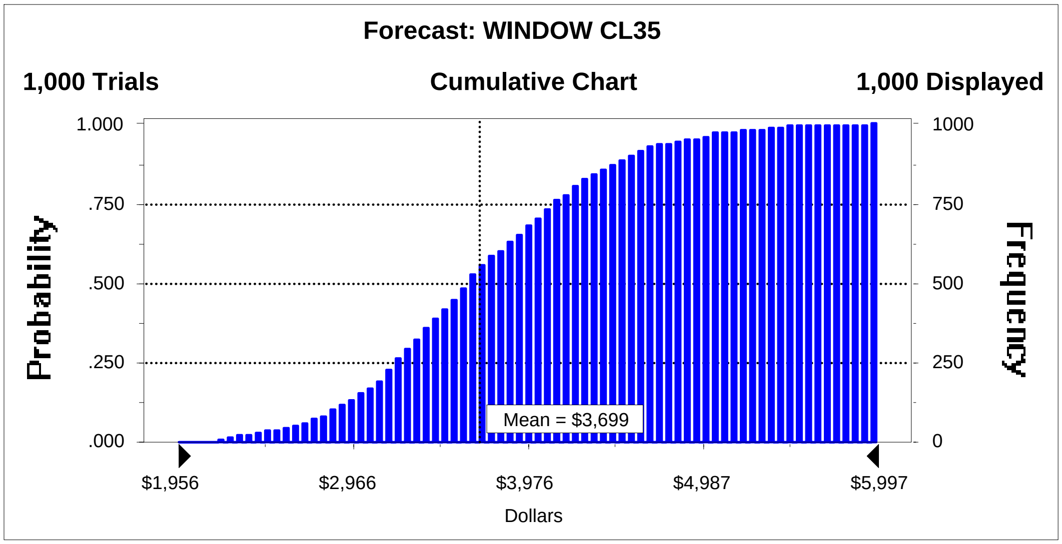


**Figure G-124: Climate Zone 3 Class 35 Window NPV Results for Electric FAF**

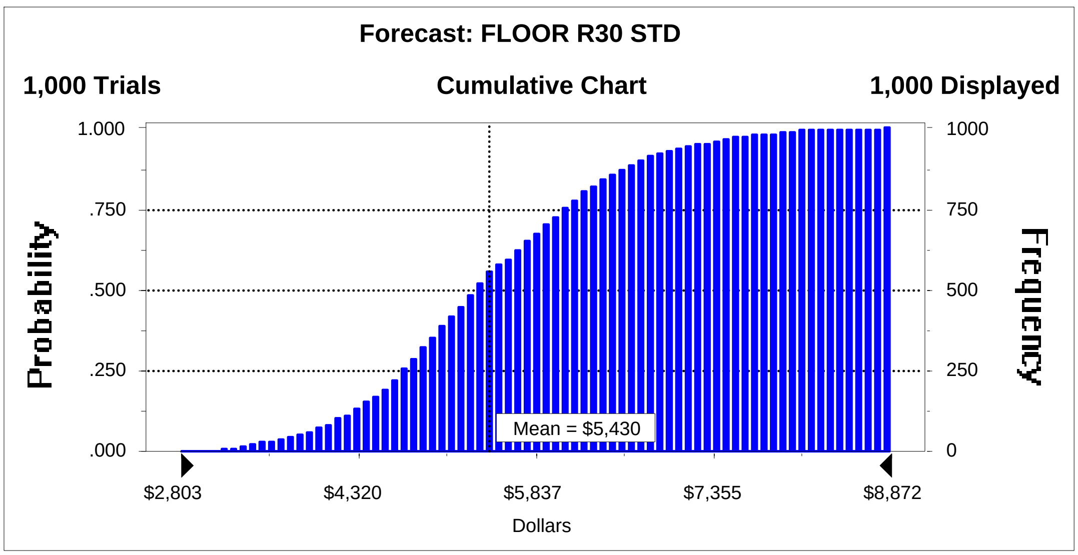


**Figure G-125: Climate Zone 3 R30 Under floor NPV Results for Electric FAF**

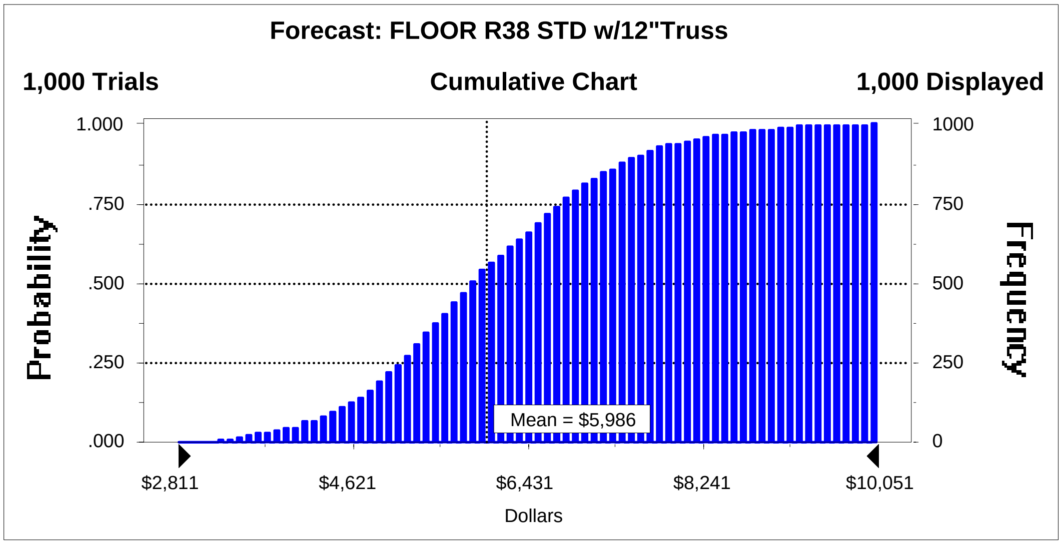


**Figure G-126: Climate Zone 3 R38 Under floor NPV Results for Electric FAF**

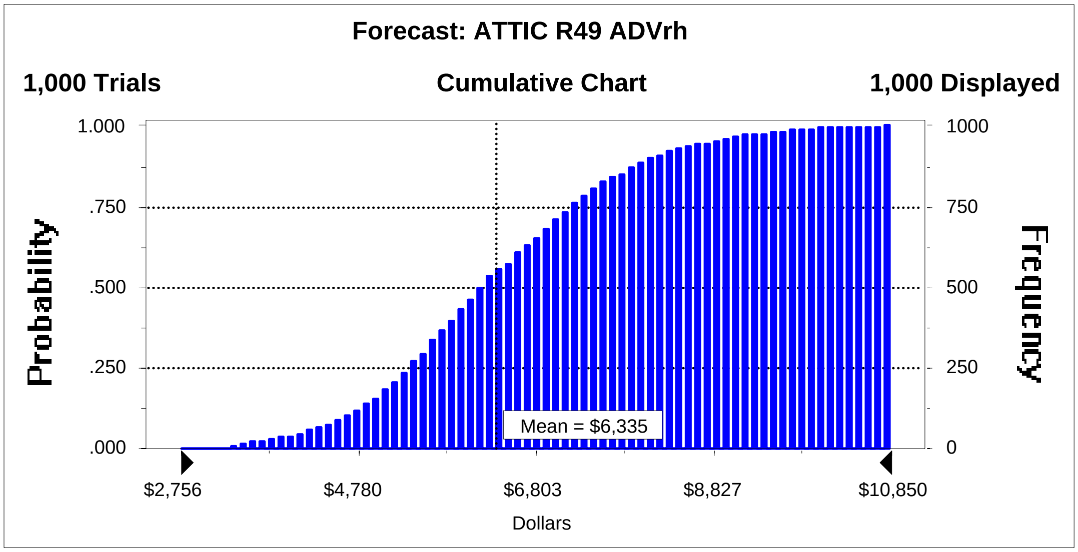


**Figure G-127: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric FAF**

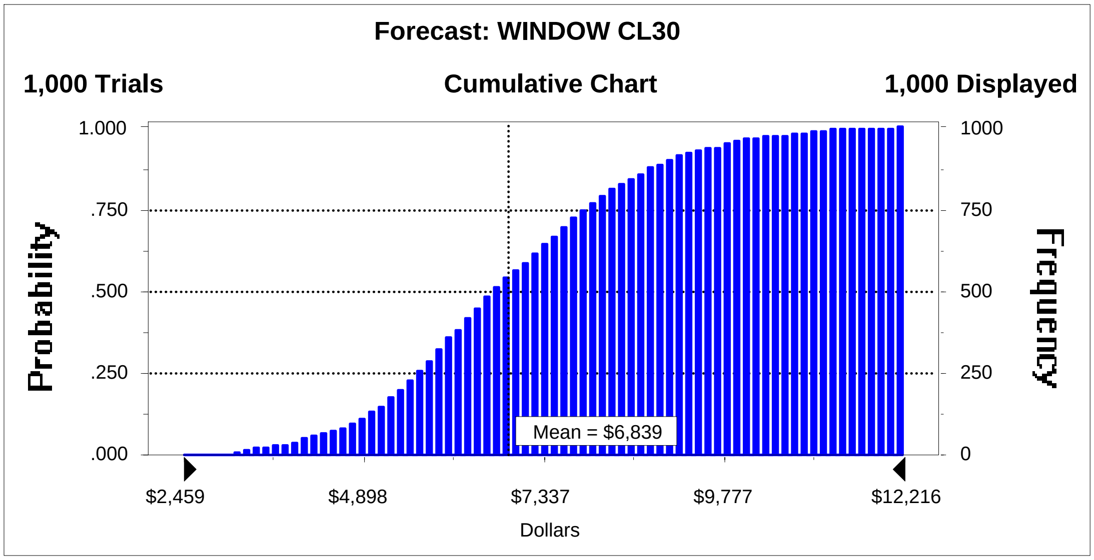


**Figure G-128: Climate Zone 3 Class 30 Window NPV Results for Electric FAF**

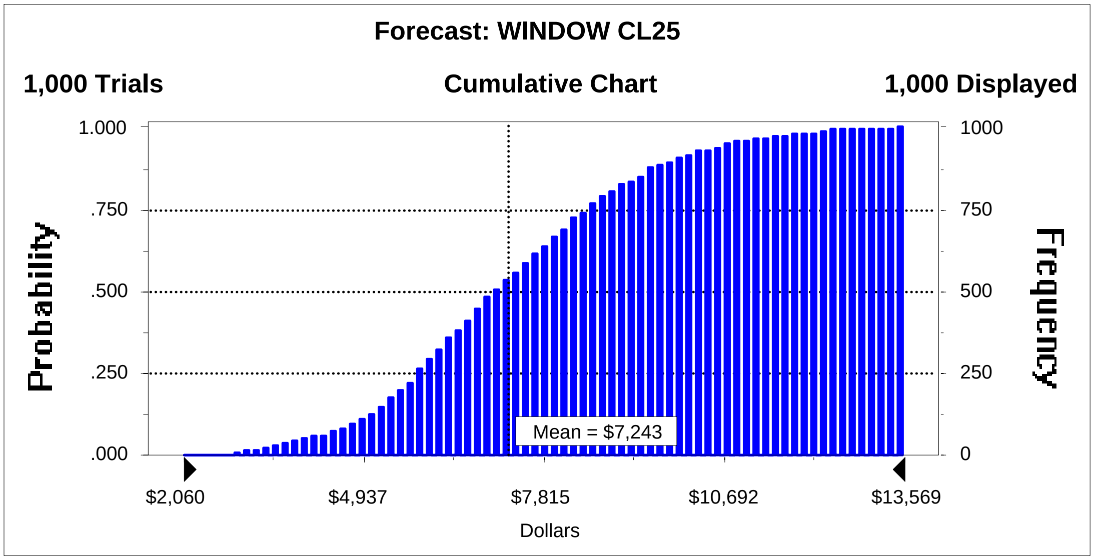


**Figure G-129: Climate Zone 3 Class 25 Window NPV Results for Electric FAF**

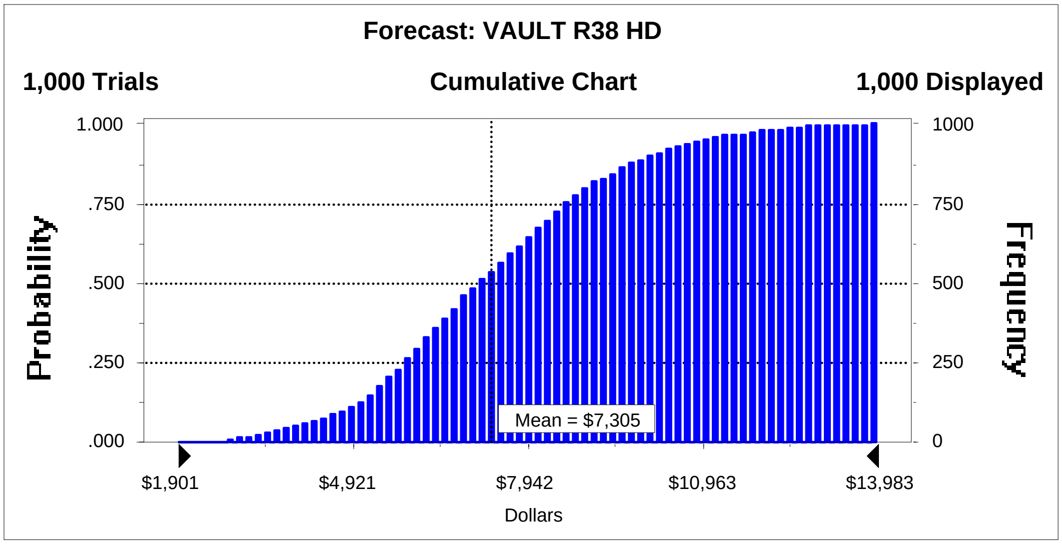


**Figure G-130: Climate Zone 3 R38 Vault NPV Results for Electric FAF**

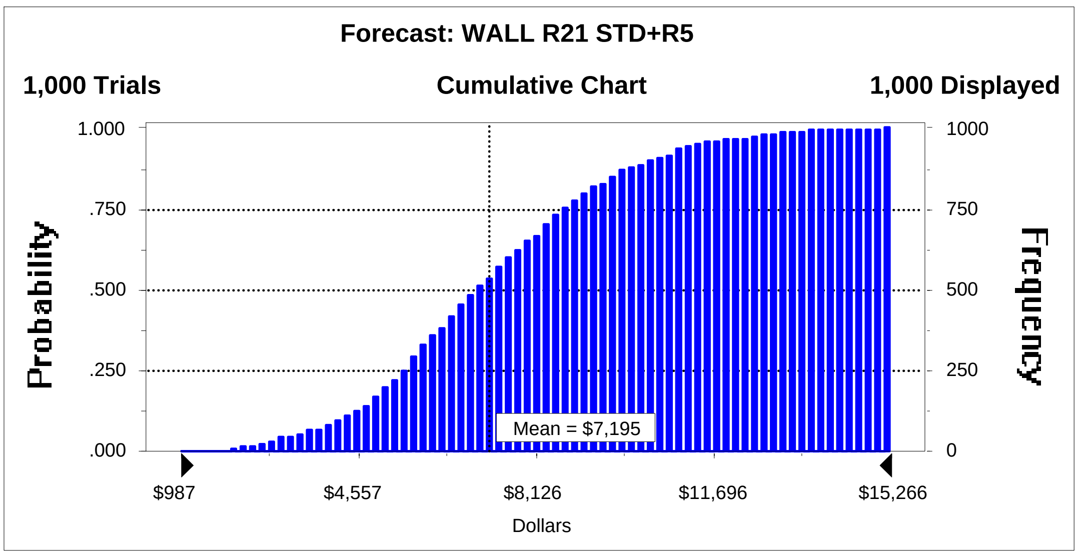


**Figure G-131: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric FAF**

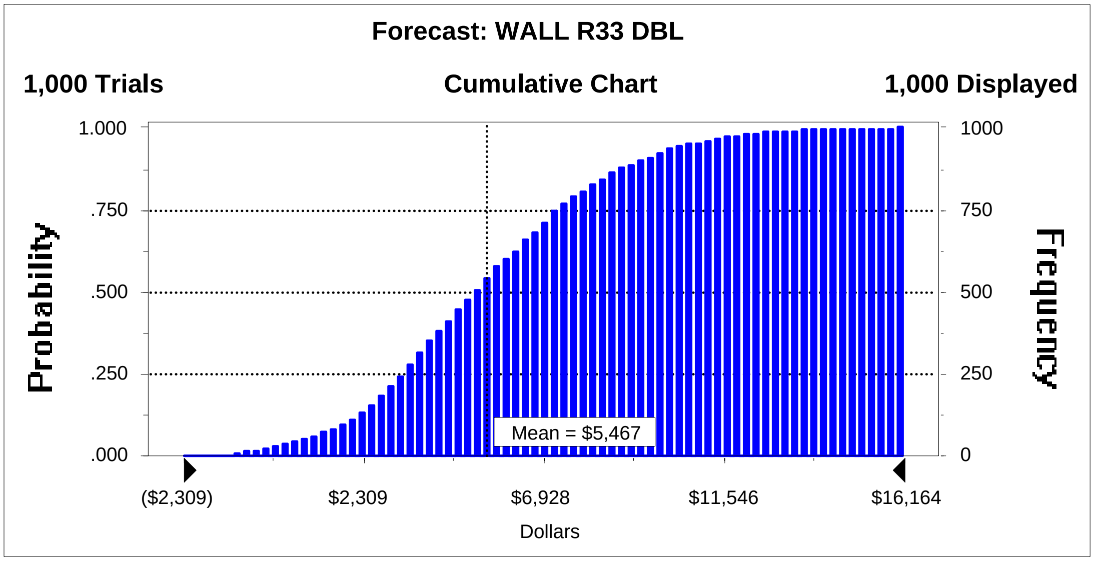


**Figure G-132: Climate Zone 3 R33 Wall NPV Results for Electric FAF**

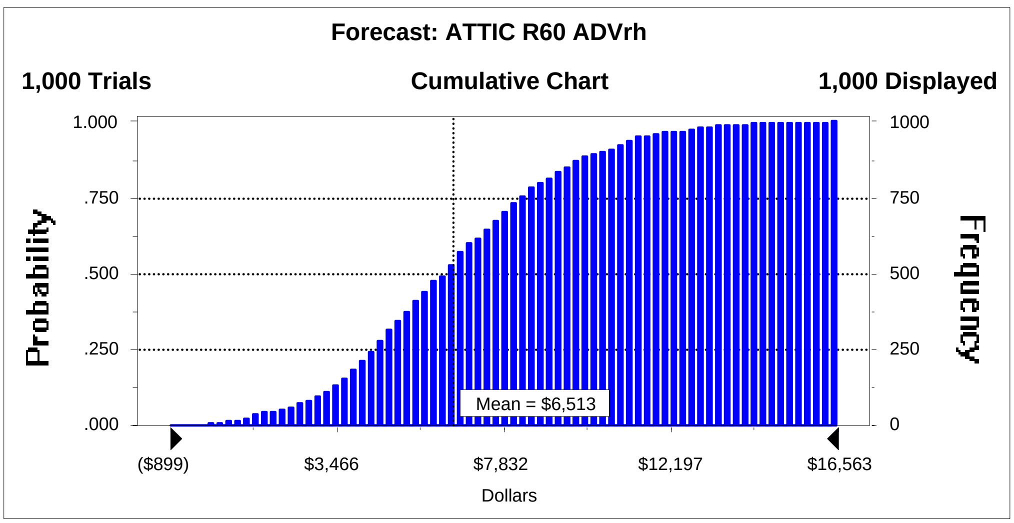


**Figure G-133: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric FAF**

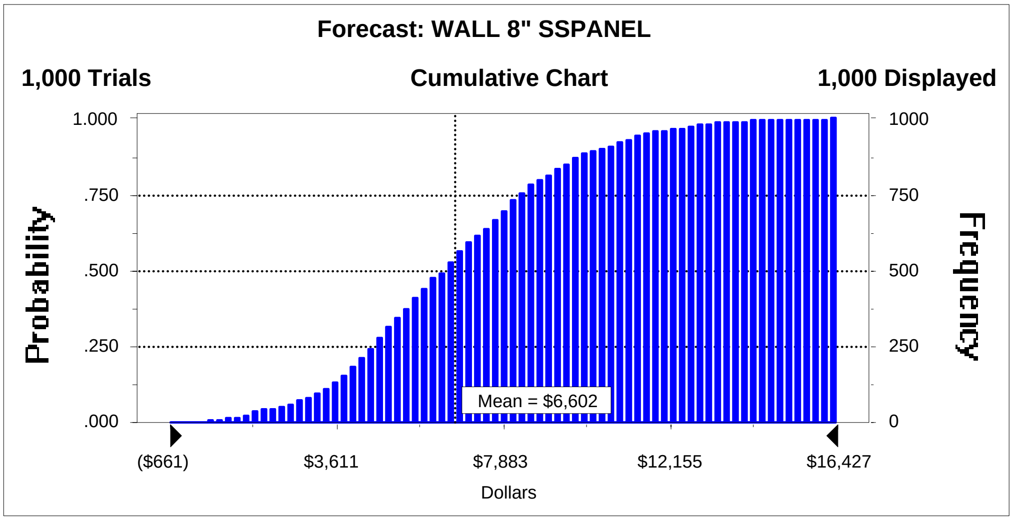


**Figure G-134: Climate Zone 3 R38 Wall NPV Results for Electric FAF**

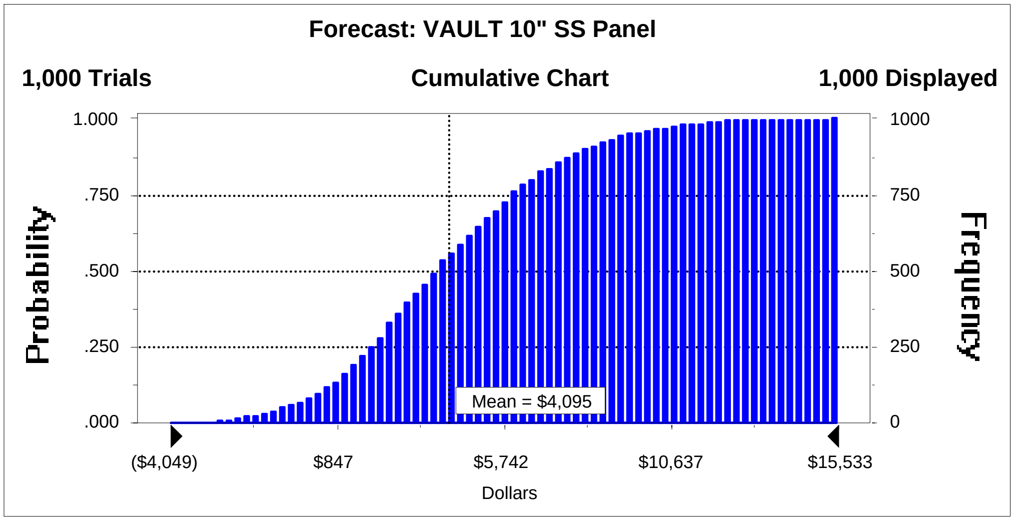


**Figure G-135: Climate Zone 3 R49 Vault NPV Results for Electric FAF**

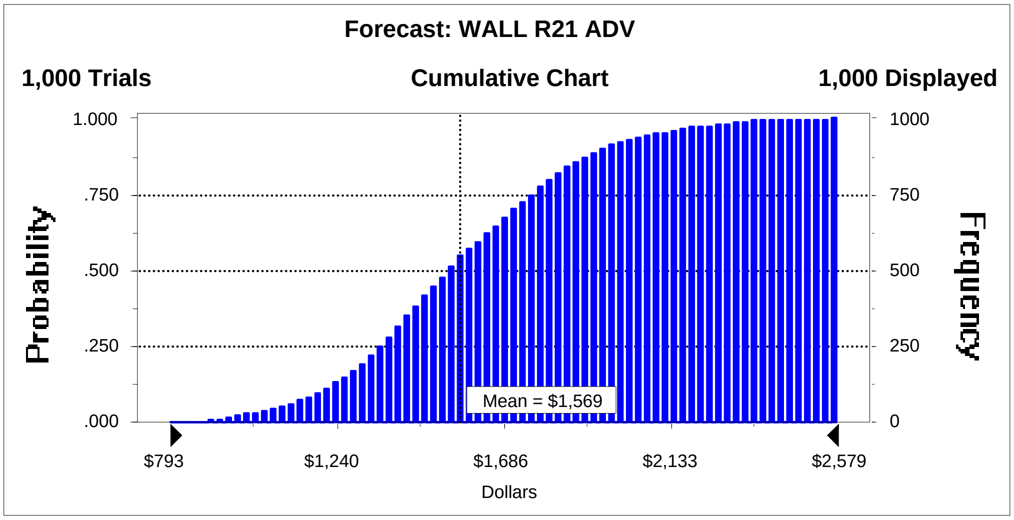


**Figure G-136: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric Zonal**

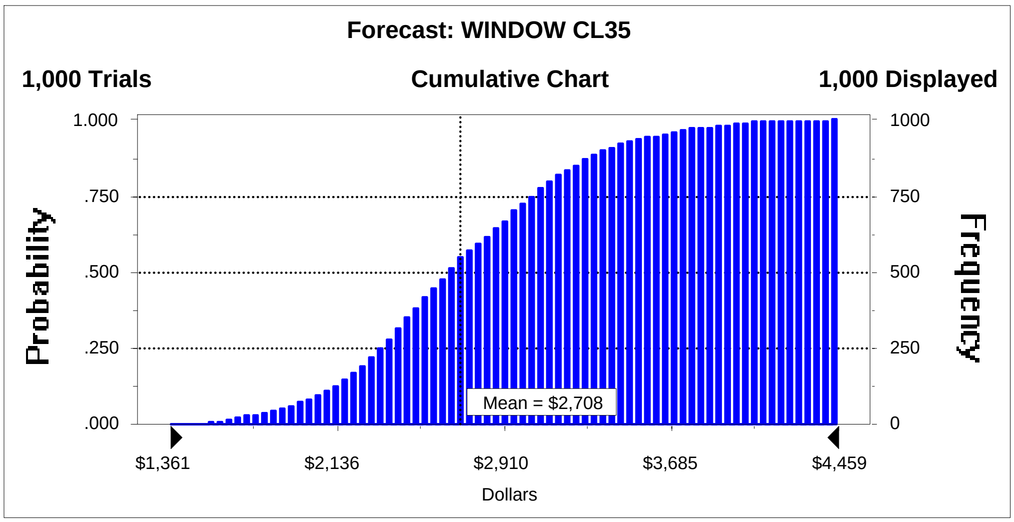


**Figure G-137: Climate Zone 3 Class 35 Window NPV Results for Electric Zonal**

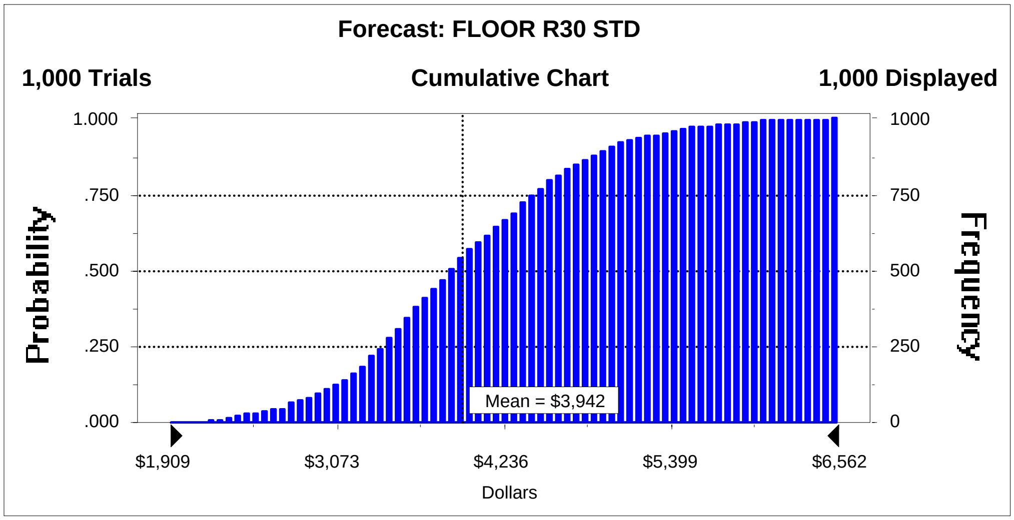


**Figure G-138: Climate Zone 3 R30 Under floor NPV Results for Electric Zonal**

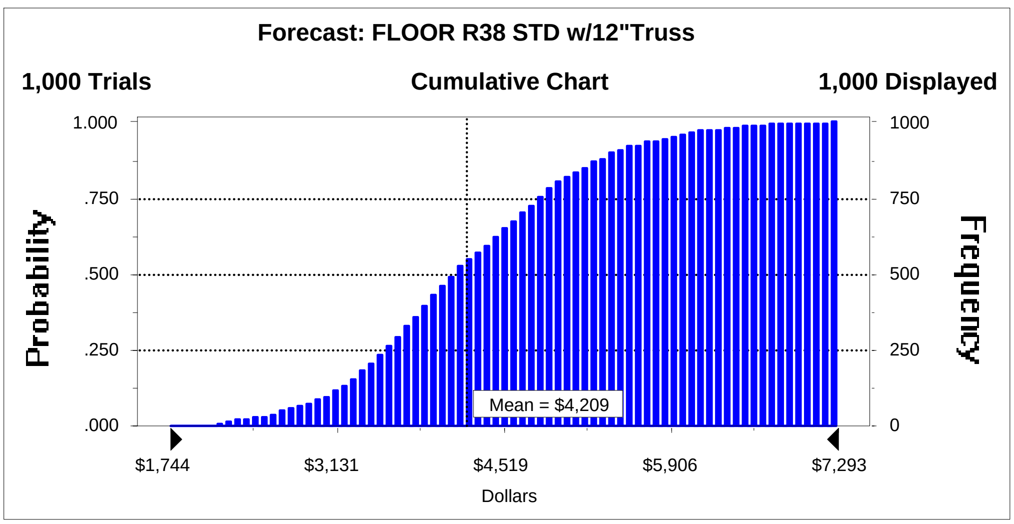


**Figure G-139: Climate Zone 3 R38 Under floor NPV Results for Electric Zonal**

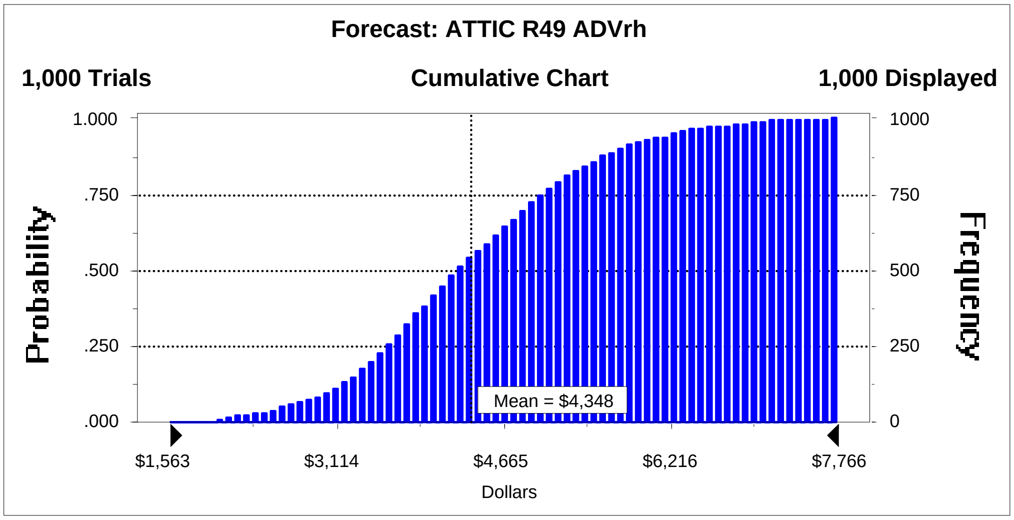


**Figure G-140: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric Zonal**

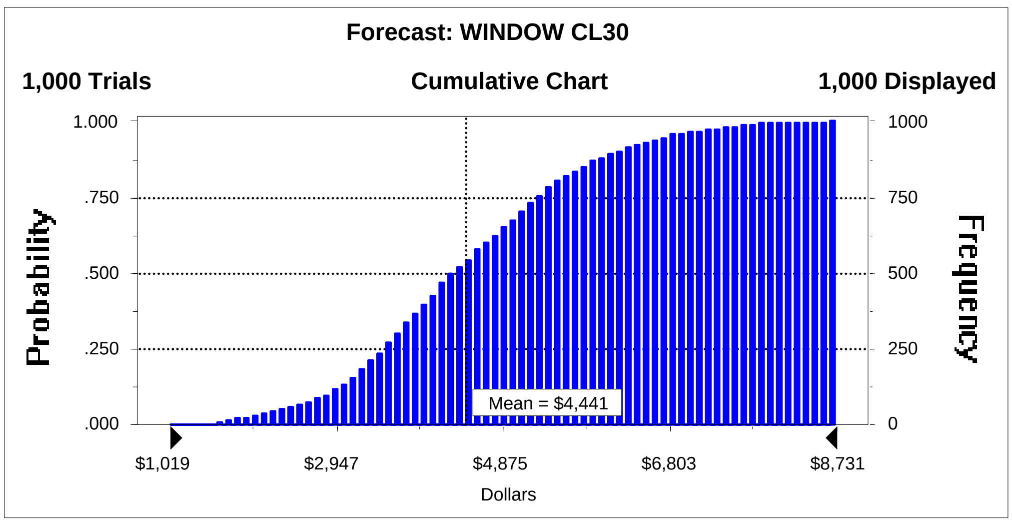


**Figure G-141: Climate Zone 3 Class 30 Window NPV Results for Electric Zonal**

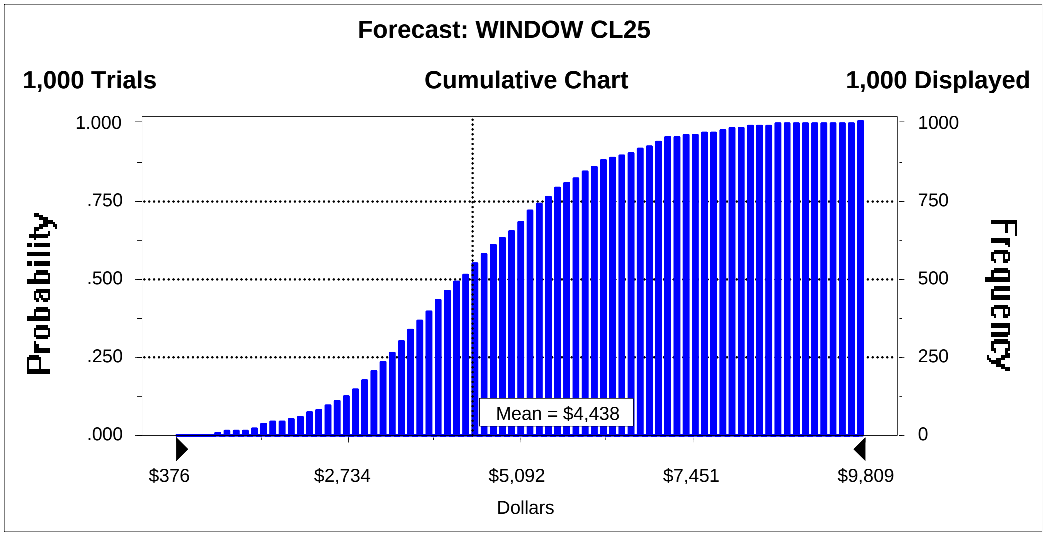


**Figure G-142: Climate Zone 3 Class 25 Window NPV Results for Electric Zonal**

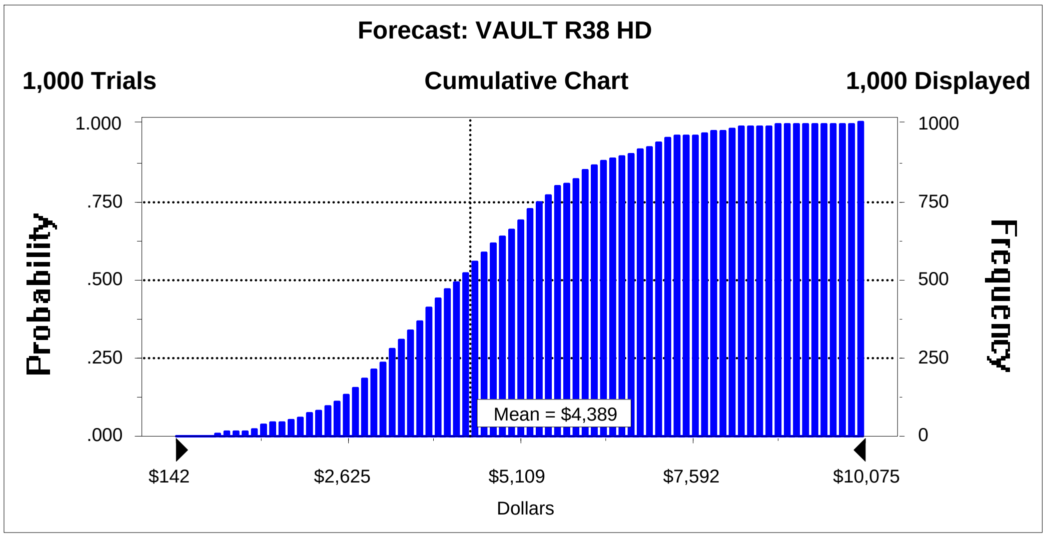


**Figure G-143: Climate Zone 3 R38 Vault NPV Results for Electric Zonal**

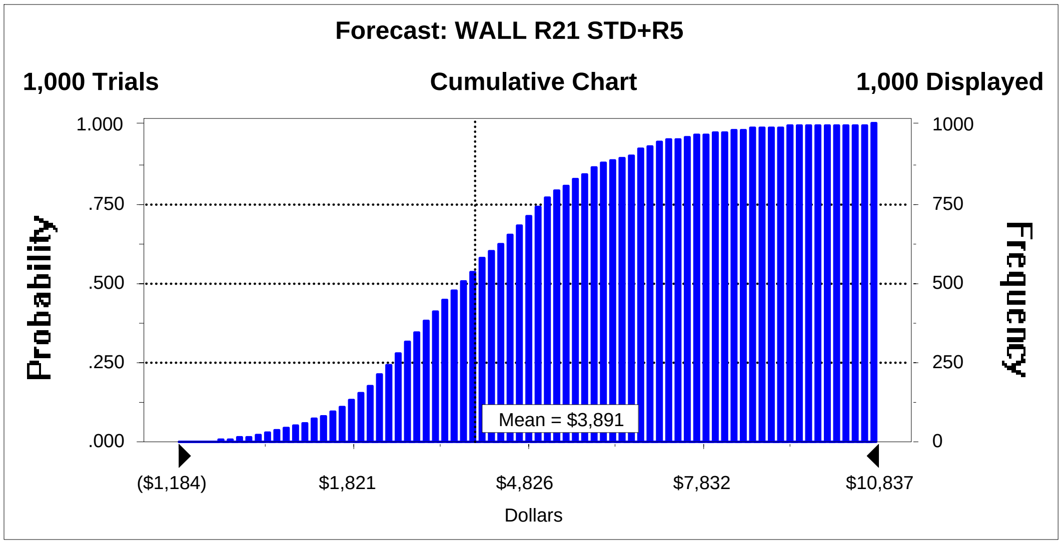


**Figure G-144: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric Zonal**

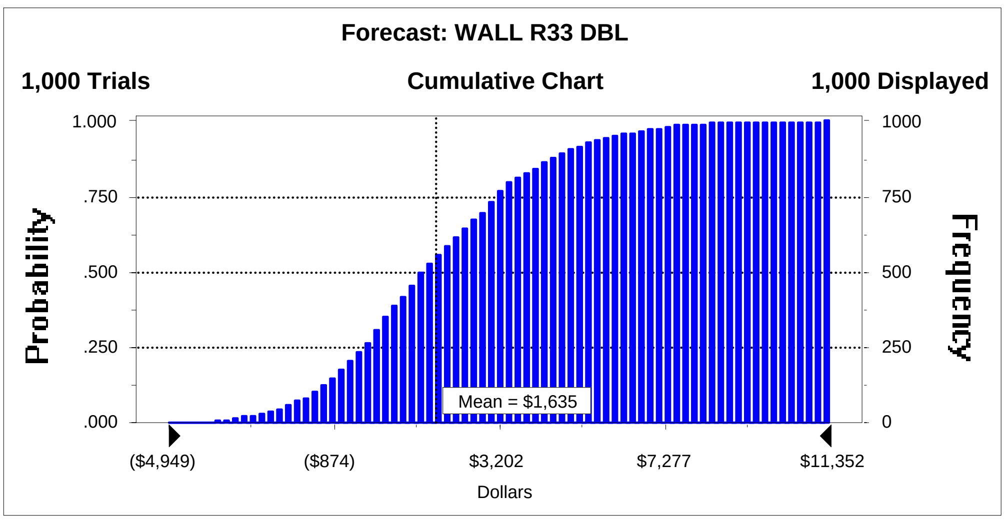


**Figure G-145: Climate Zone 3 R33 Wall NPV Results for Electric Zonal**

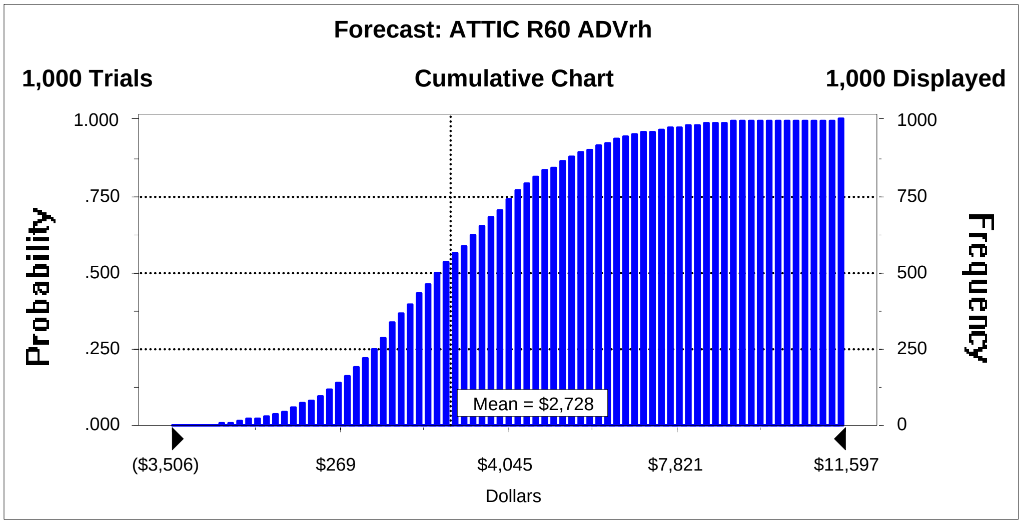


**Figure G-146: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric Zonal**

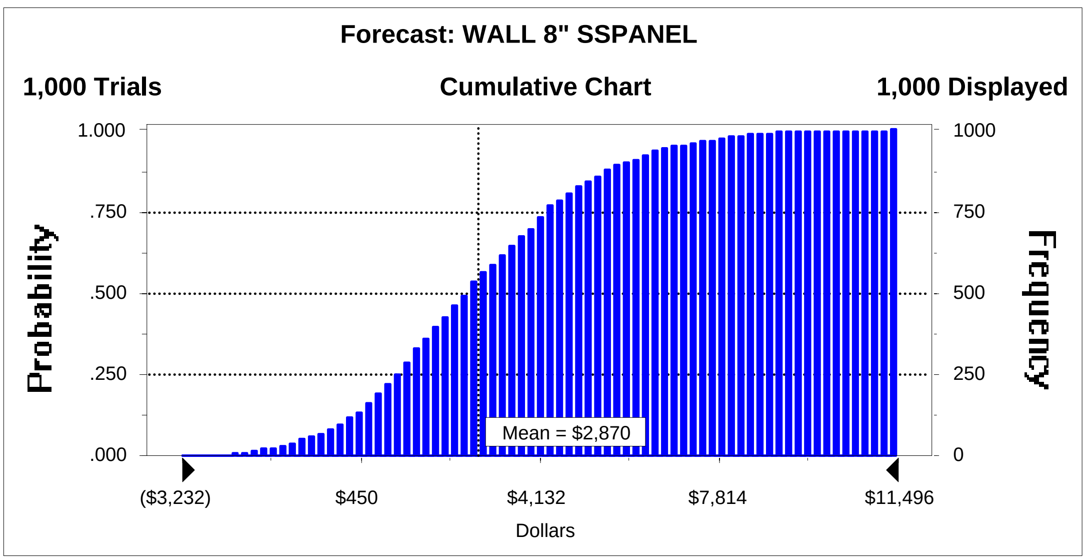


**Figure G-147: Climate Zone 3 R38 Wall NPV Results for Electric Zonal**

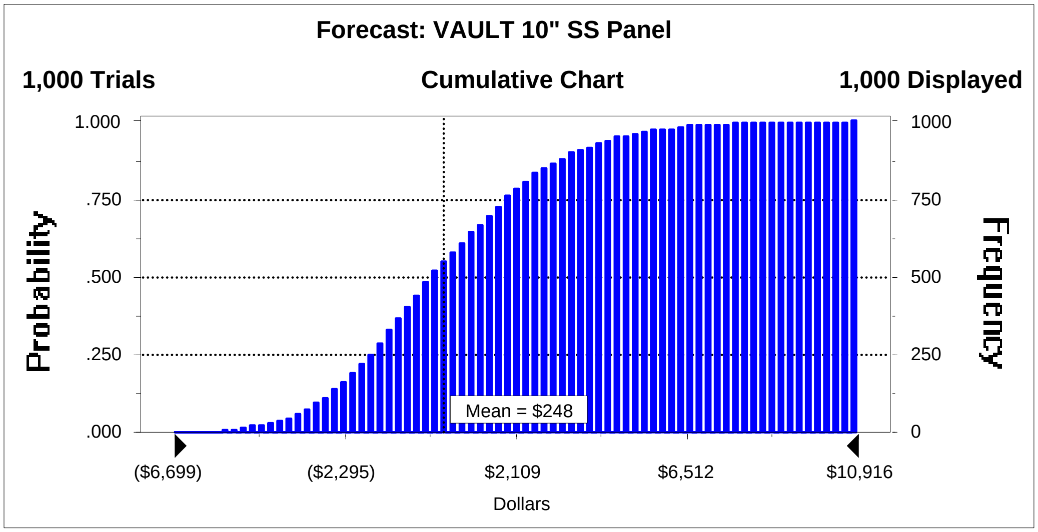


**Figure G-148: Climate Zone 3 R49 Vault NPV Results for Electric Zonal**

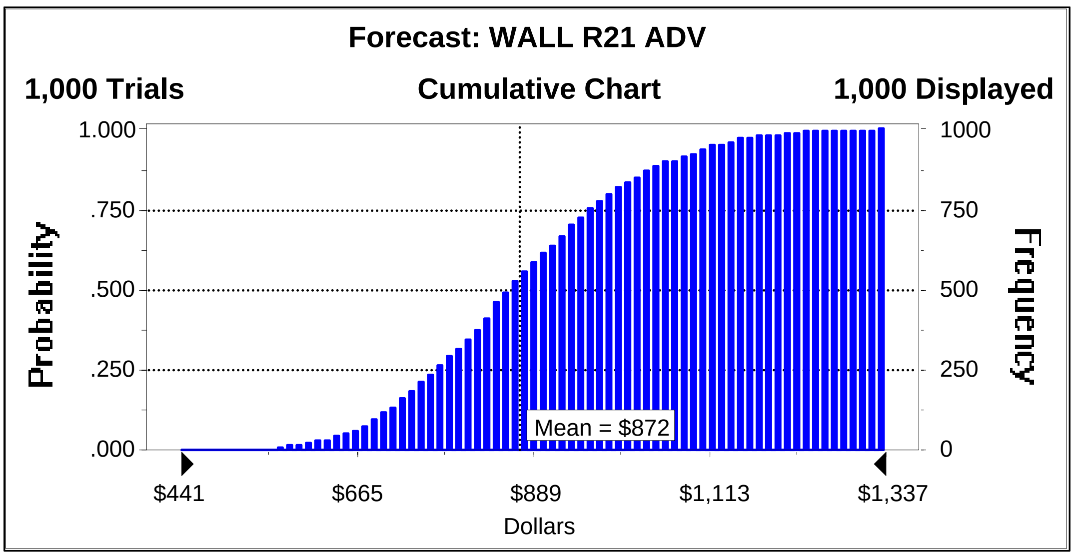


**Figure G-149: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Gas FAF**

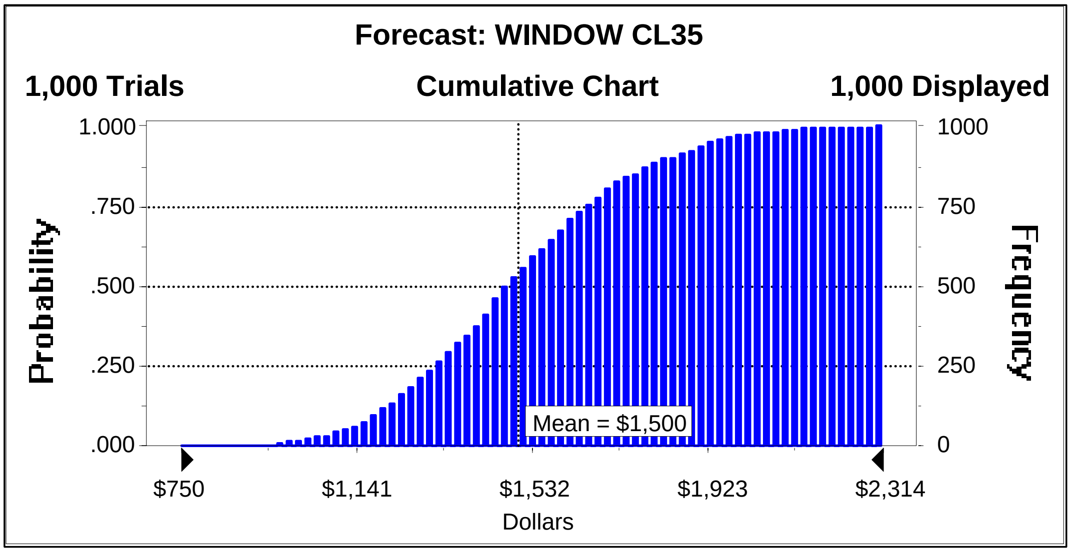


**Figure G-150: Climate Zone 3 Class 35 Window NPV Results for Gas FAF**

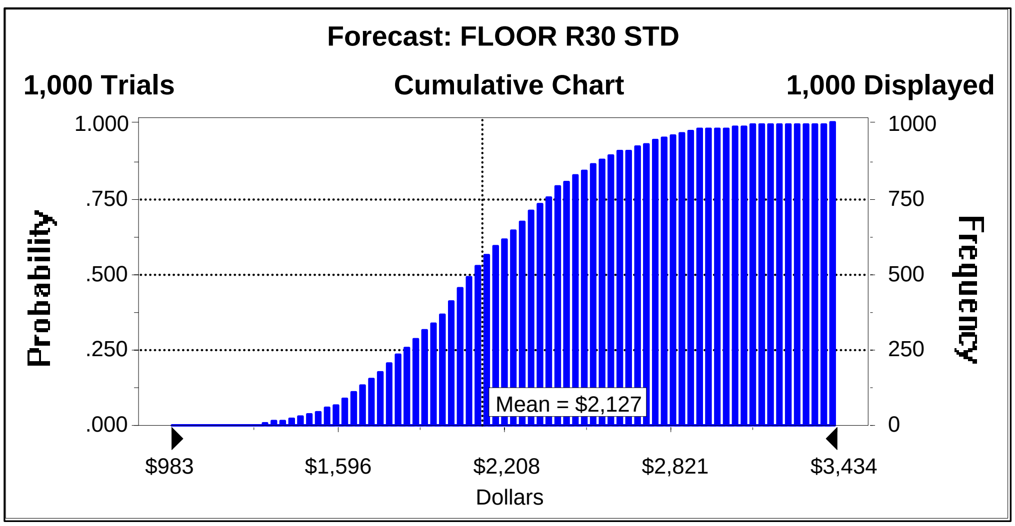


**Figure G-151: Climate Zone 3 R30 Under floor NPV Results for Gas FAF**

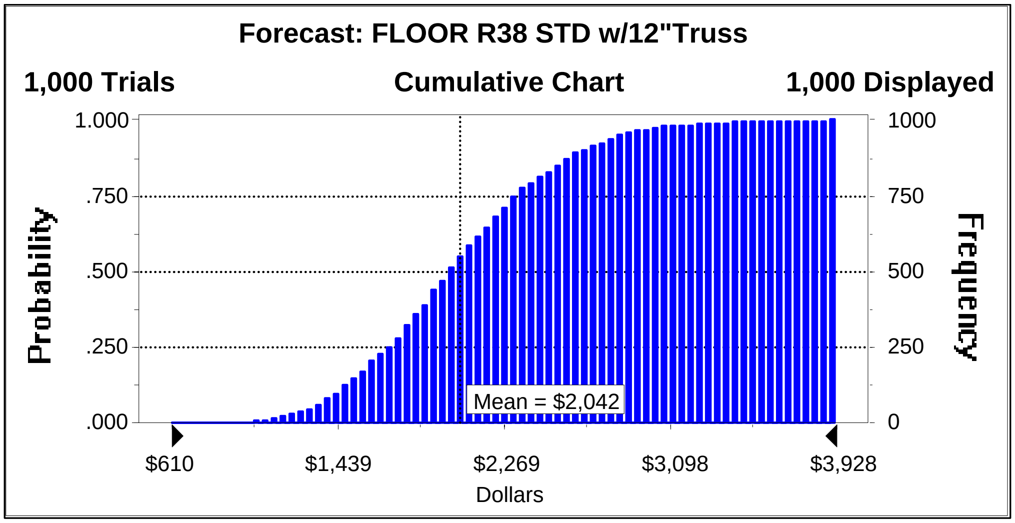


**Figure G-152: Climate Zone 3 R38 Under floor NPV Results for Gas FAF**

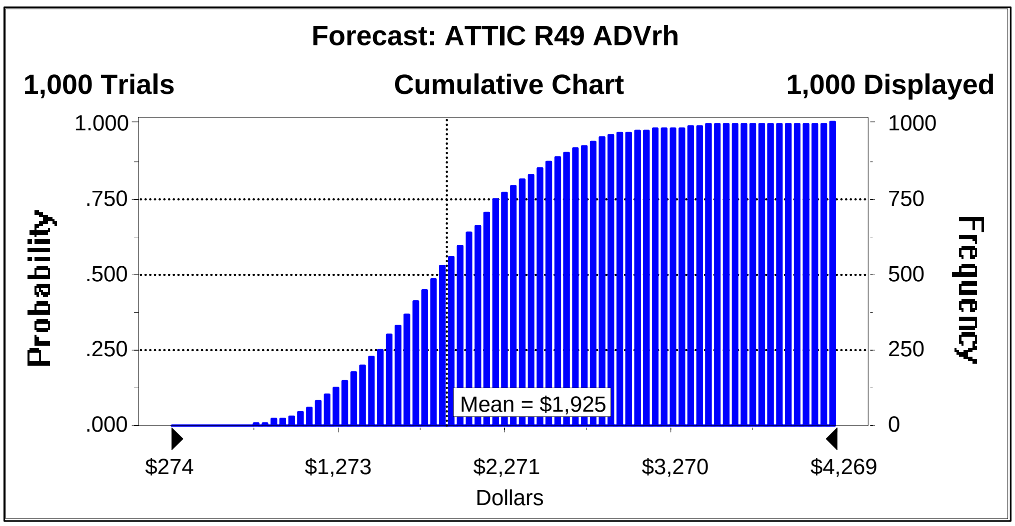


**Figure G-153: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Gas FAF**

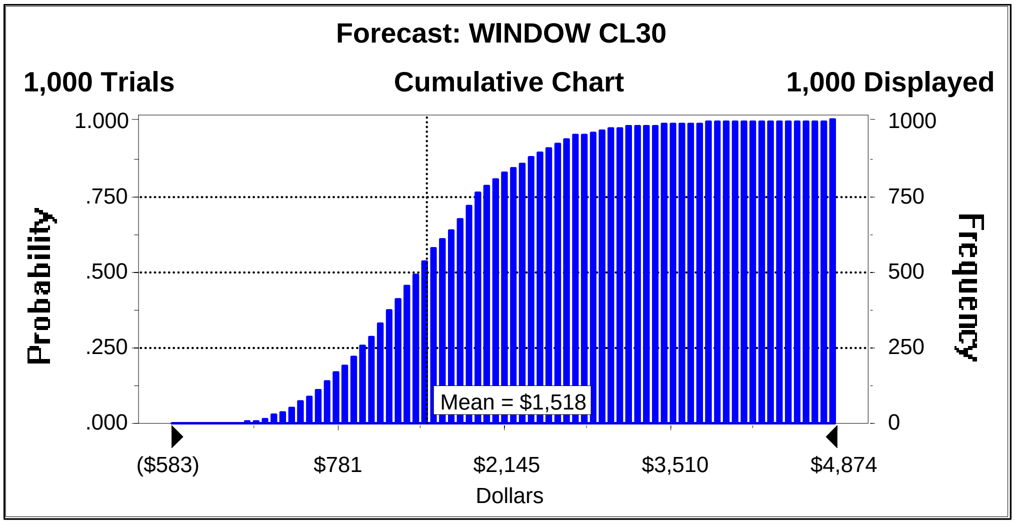


**Figure G-154: Climate Zone 3 Class 30 Window NPV Results for Gas FAF**

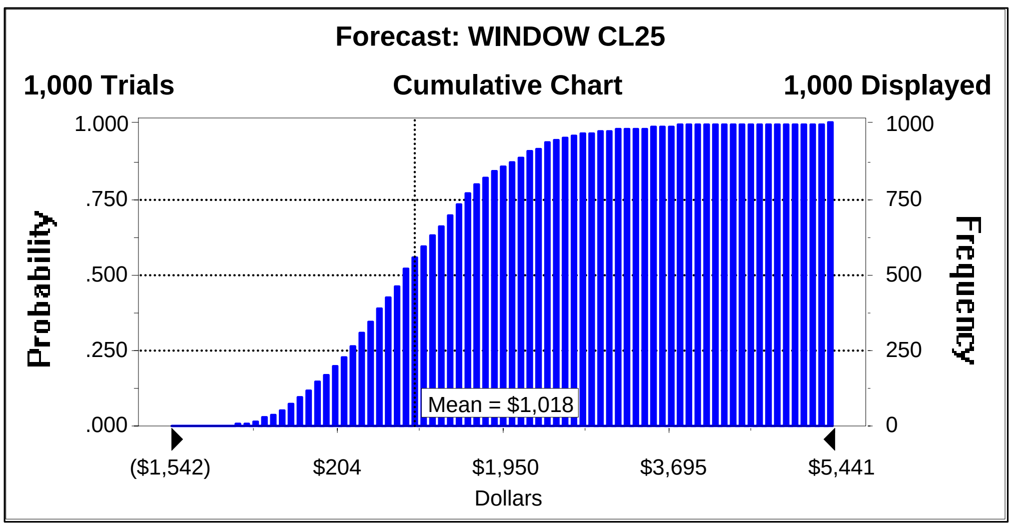


**Figure G-155: Climate Zone 3 Class 25 Window NPV Results for Gas FAF**

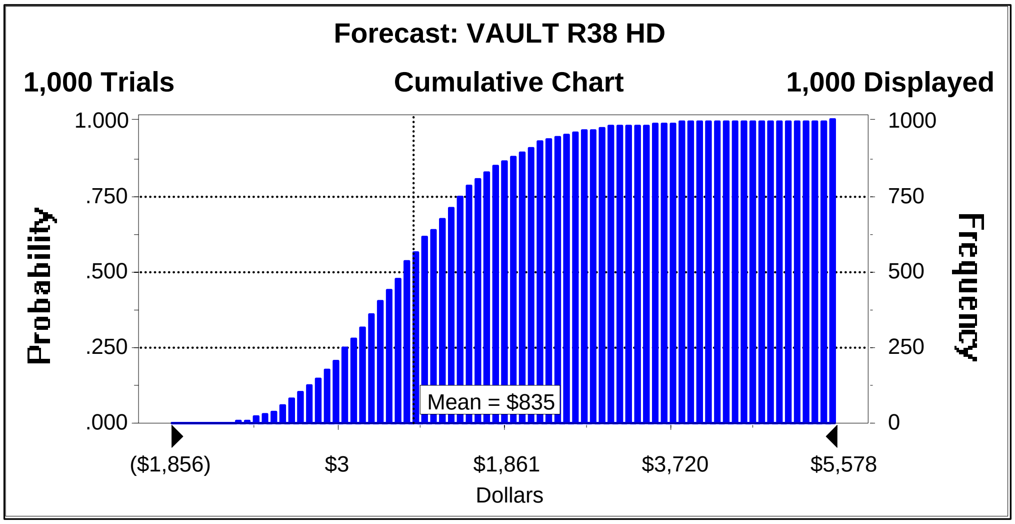


**Figure G-156: Climate Zone 3 R38 Vault NPV Results for Gas FAF**

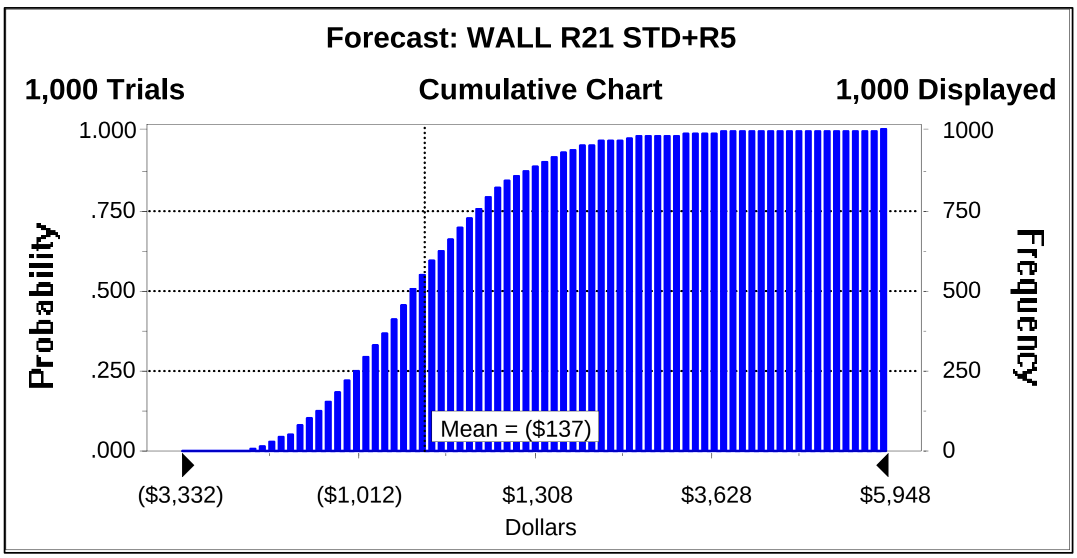


**Figure G-157: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Gas FAF**

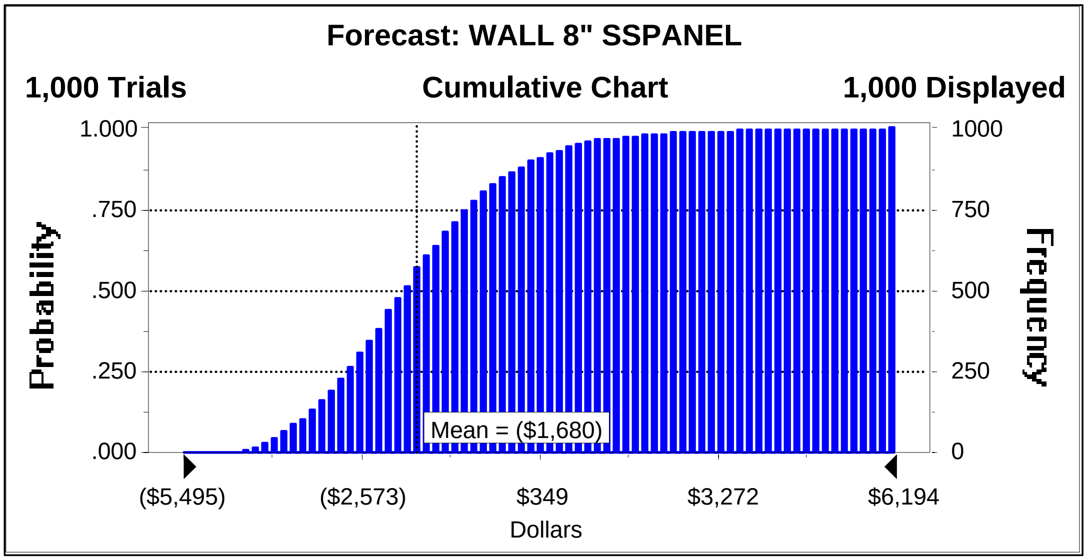


**Figure G-158: Climate Zone 3 R33 Wall NPV Results for Gas FAF**

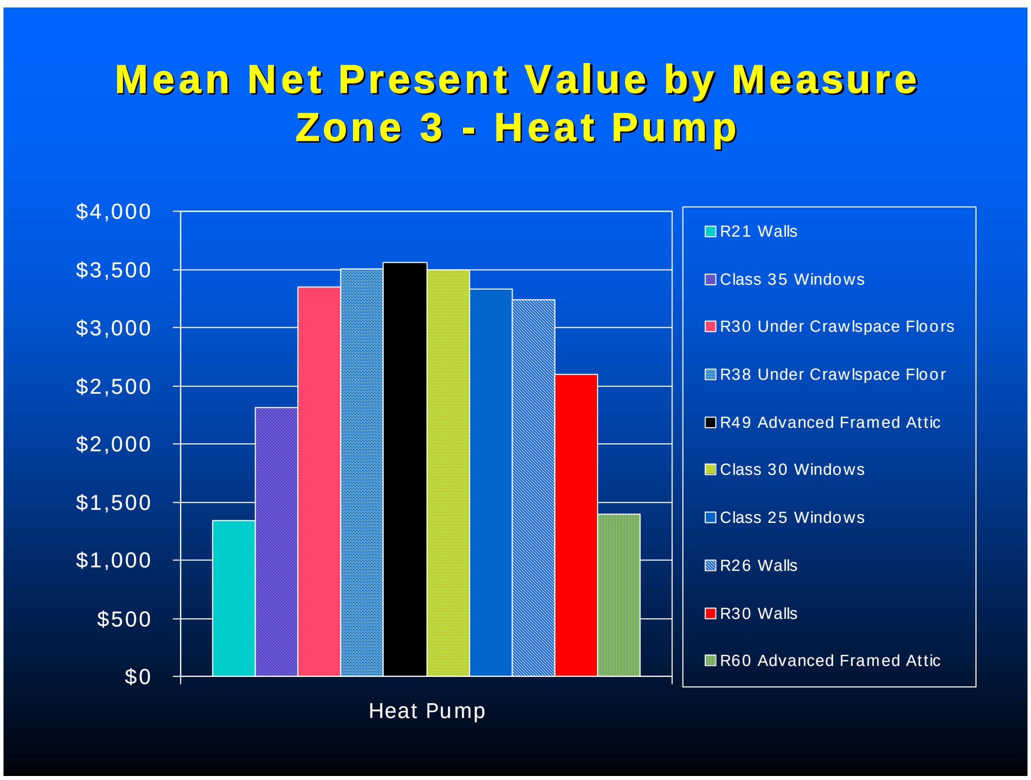


**Figure G-159: Climate Zone 3 Mean Net Present Value by Measure for Heat Pumps**

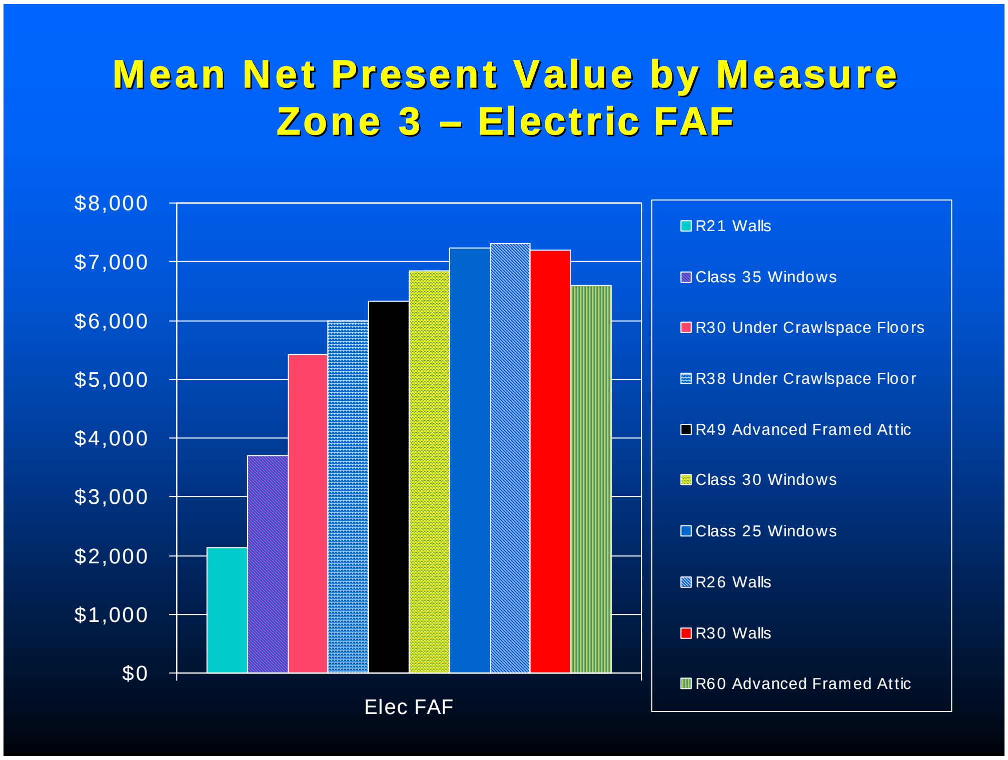


**Figure G-160: Climate Zone 3 Mean Net Present Value by Measure for Electric FAF**

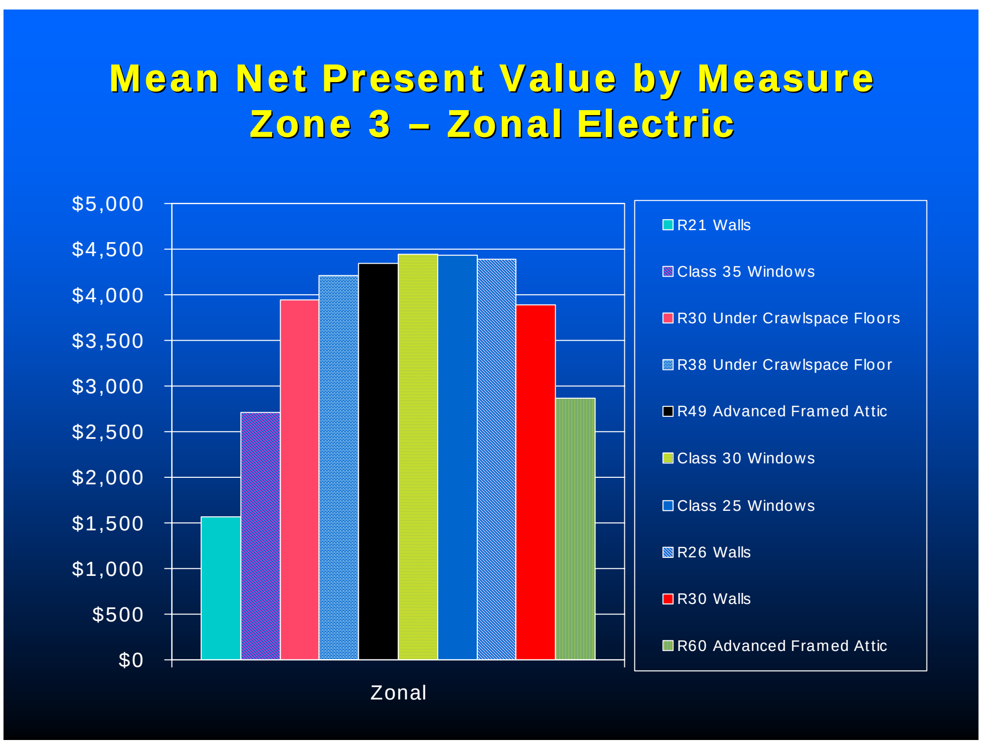


**Figure G-161: Climate Zone 3 Mean Net Present Value by Measure for Electric Zonal**

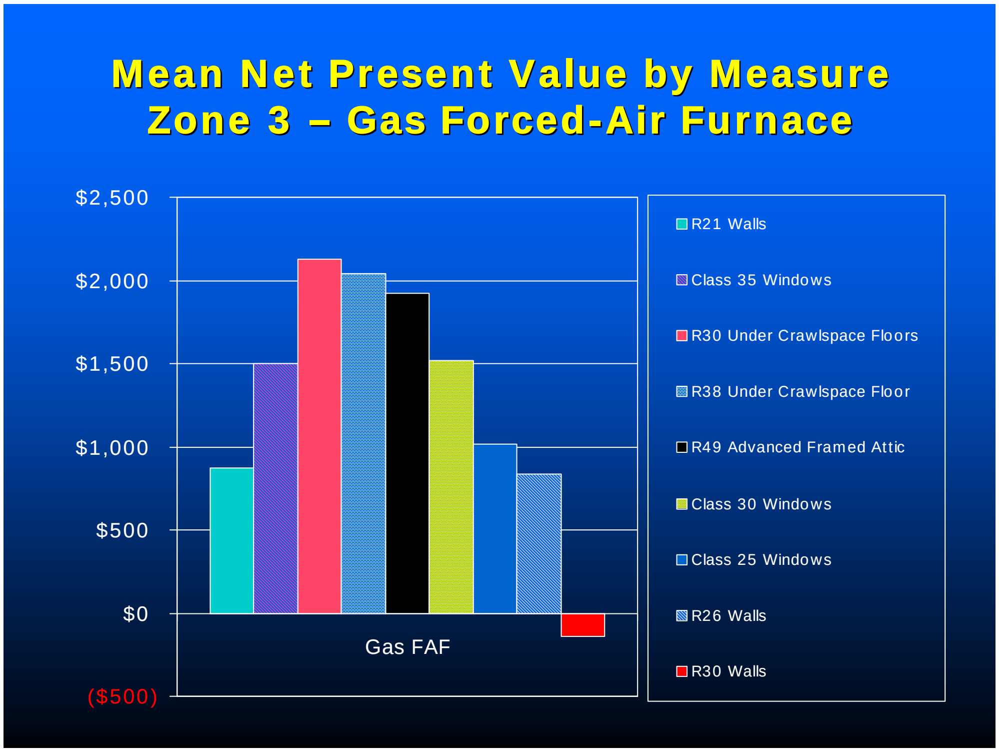


**Figure G-162: Climate Zone 3 Mean Net Present Value by Measure for Gas FAF**

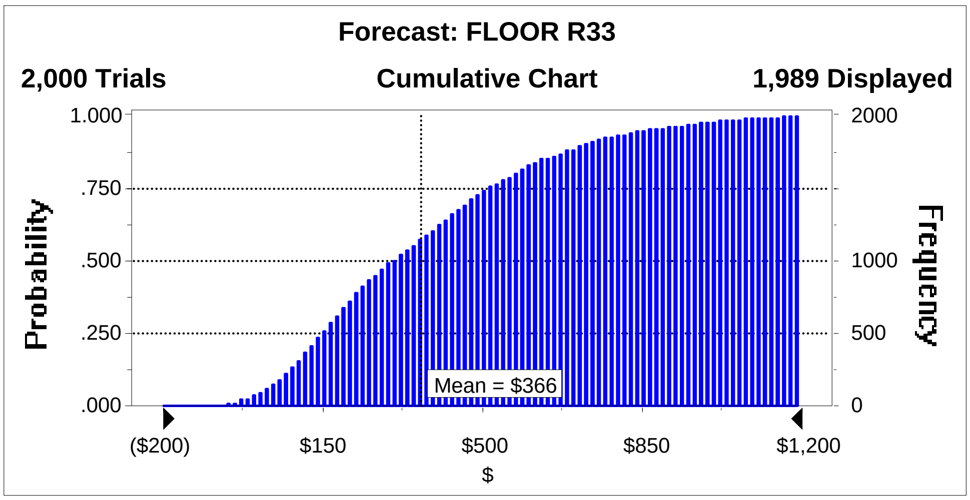


**Figure G-163: Climate Zone 1 Net Present Value Results for Manufactured Homes for R33 Floors**

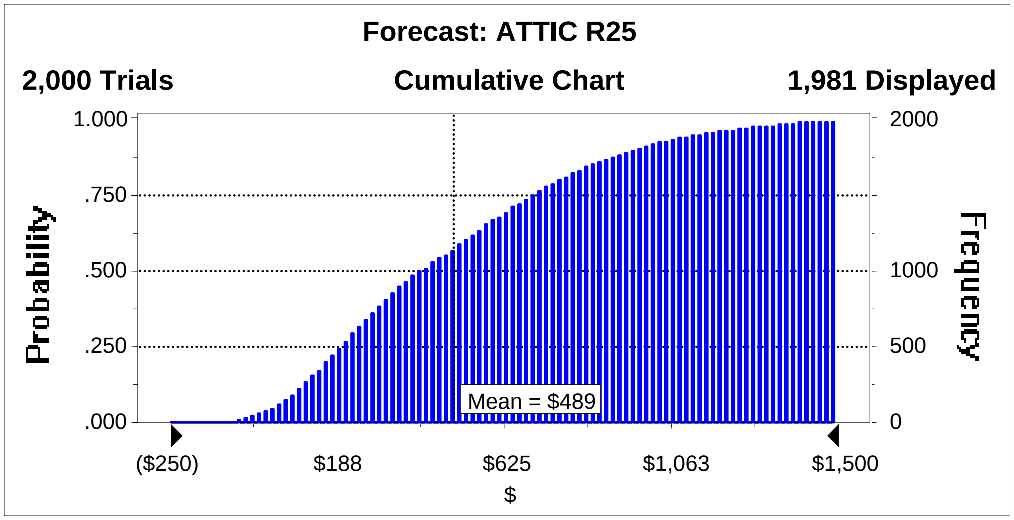


**Figure G-164: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Attic**

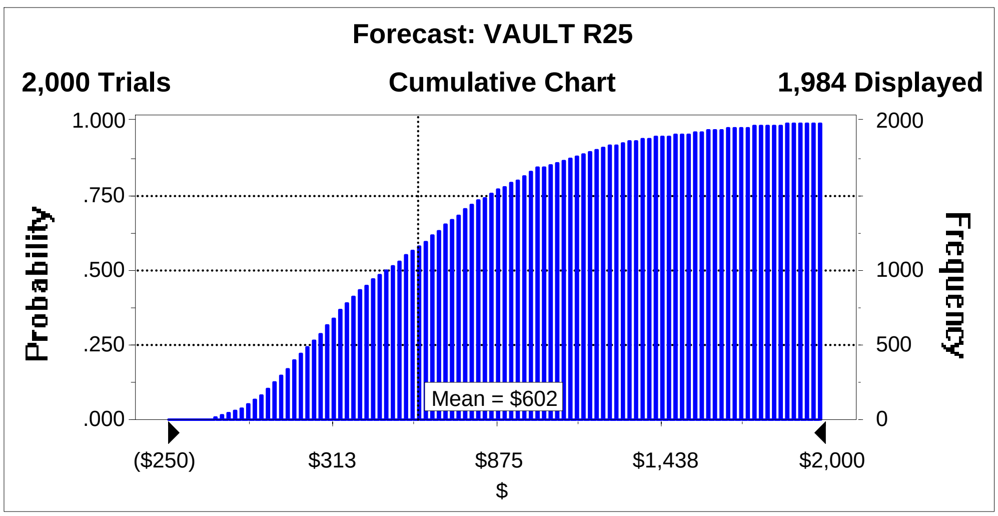


**Figure G-165: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Vault**

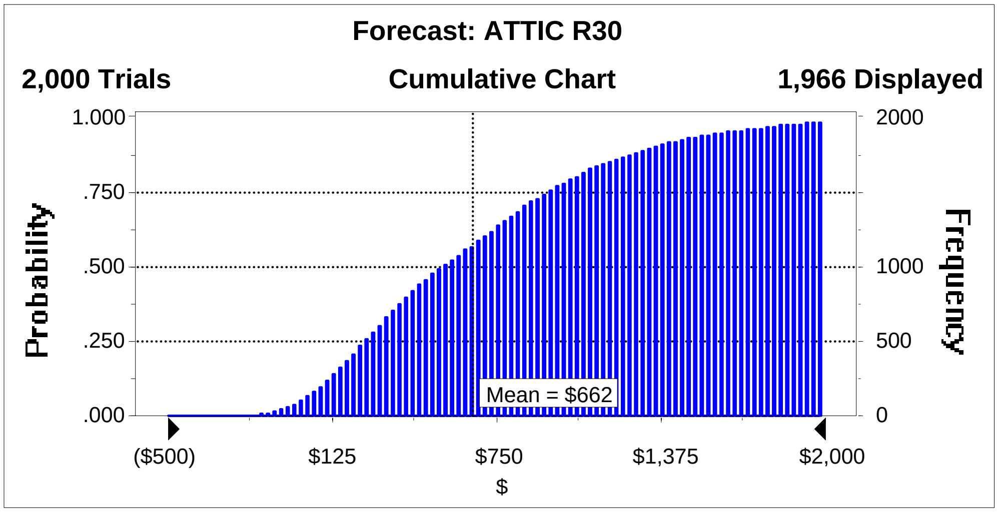


**Figure G-166: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Attic**

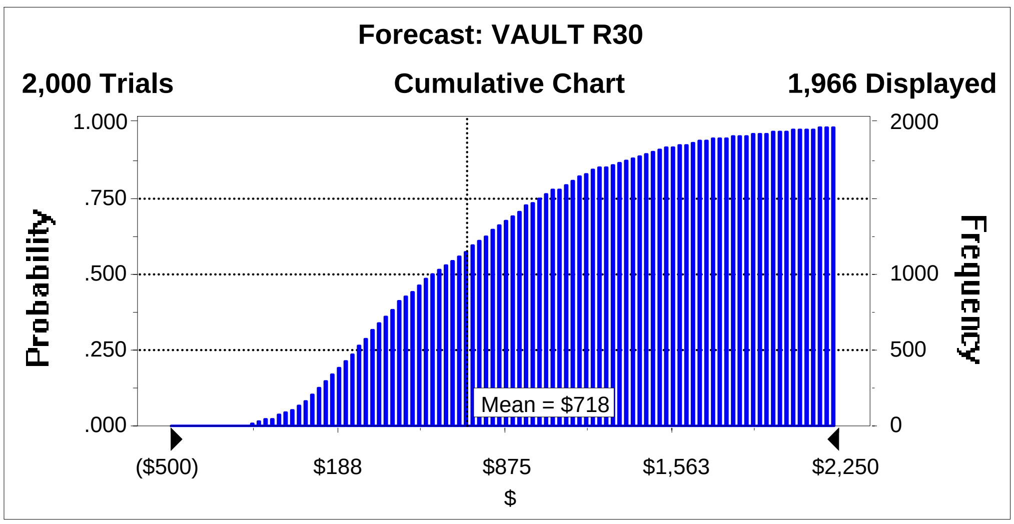


**Figure G-167: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Vaults**

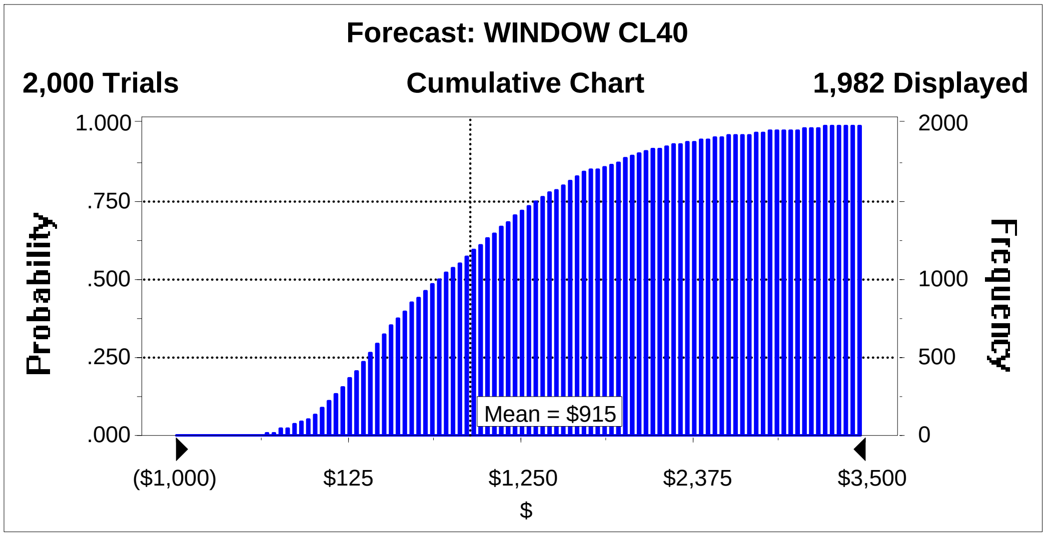


**Figure G-168: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 40 Windows**

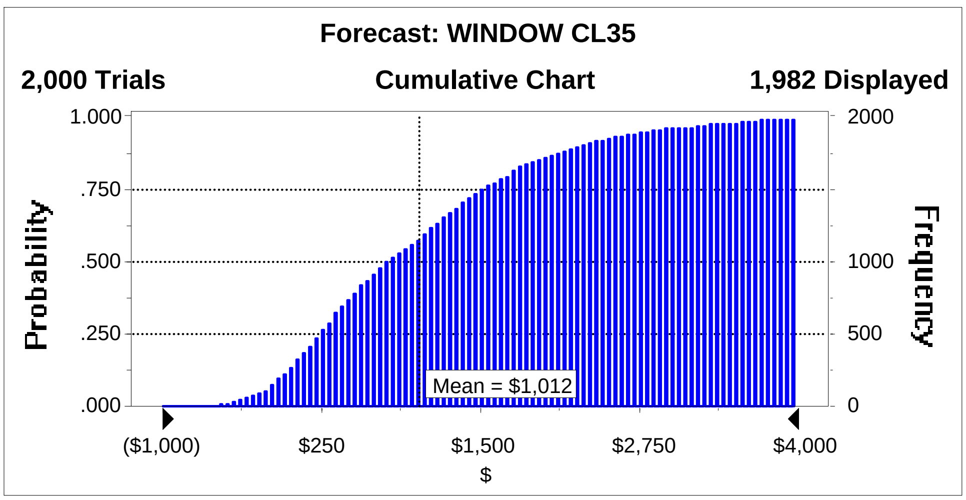


**Figure G-169: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 35 Windows**

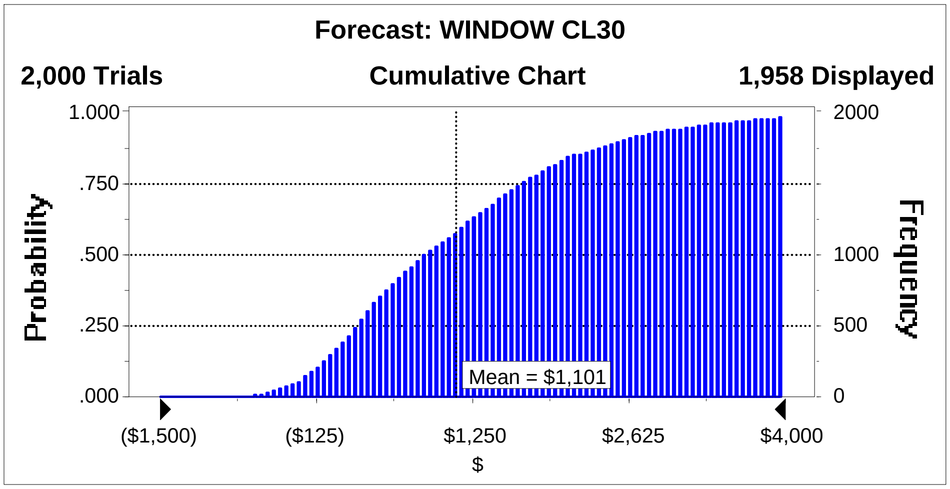


**Figure G-170: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 30 Windows**

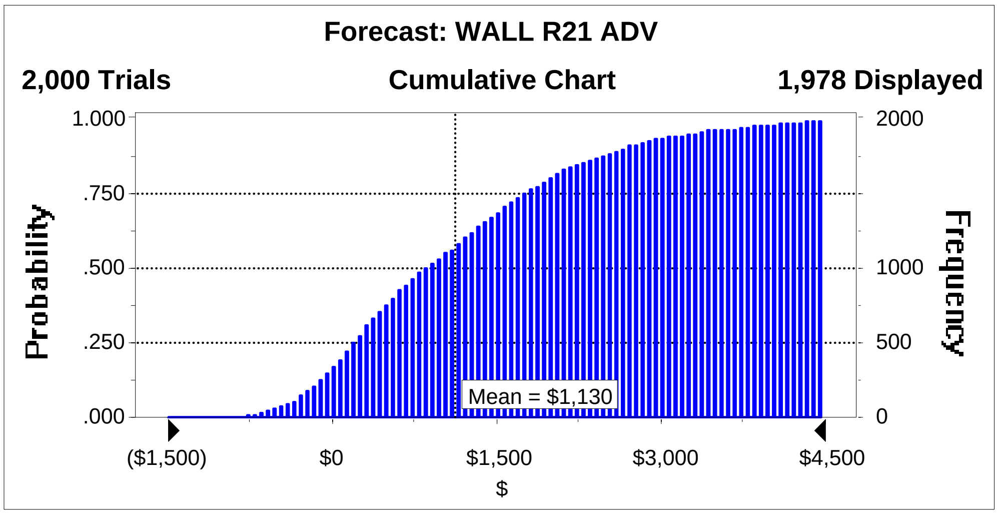


**Figure G-171: Climate Zone 1 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls**

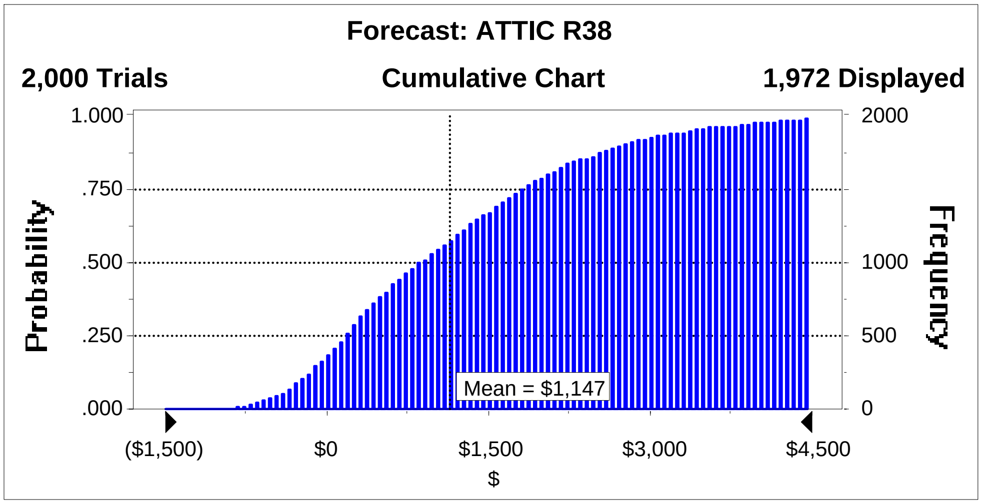


**Figure G-172: Climate Zone 1 Net Preset Value Results for Manufactured Homes for R38 Attics**

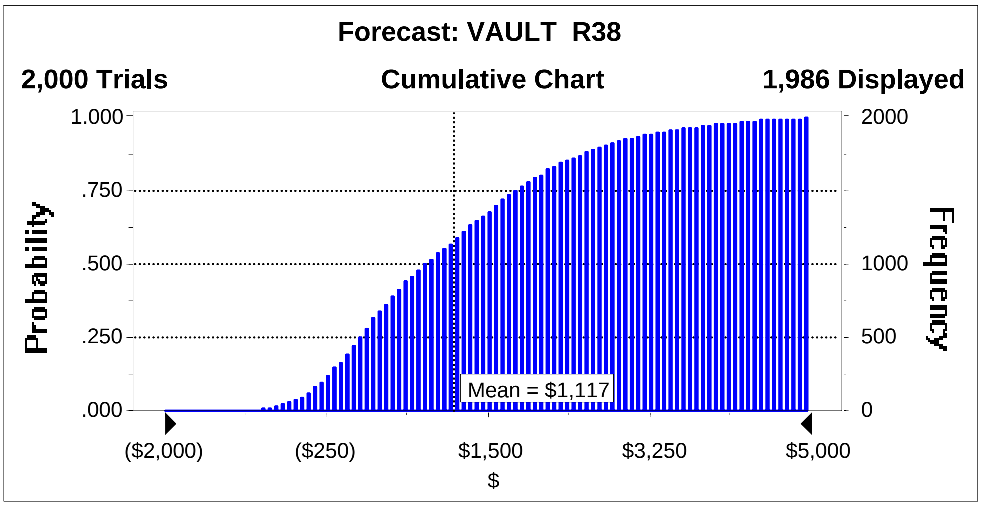


**Figure G-173: Climate Zone 1 Net Present Value Results for Manufactured Homes for R38 Vaults**

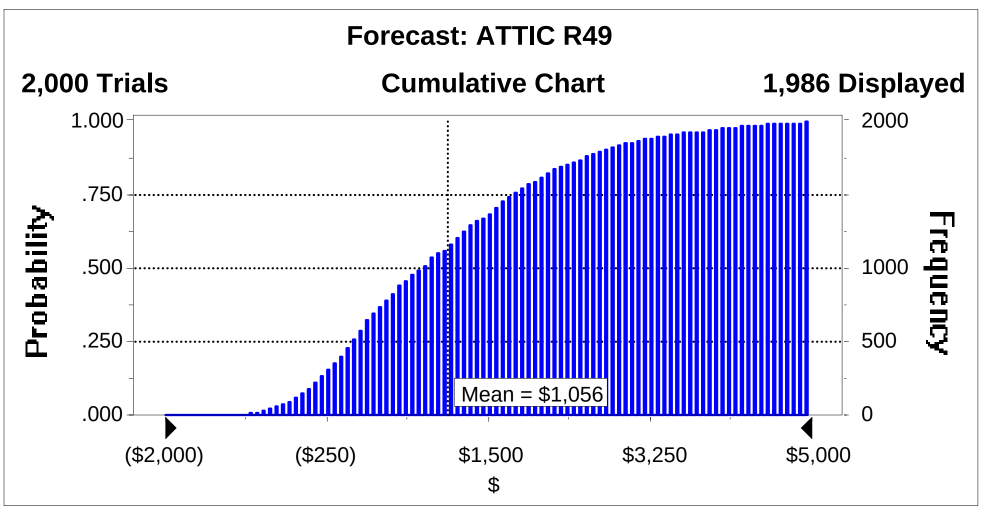


**Figure G-174: Climate Zone 1 Net Present Value Results for Manufactured Homes for R49 Attics**

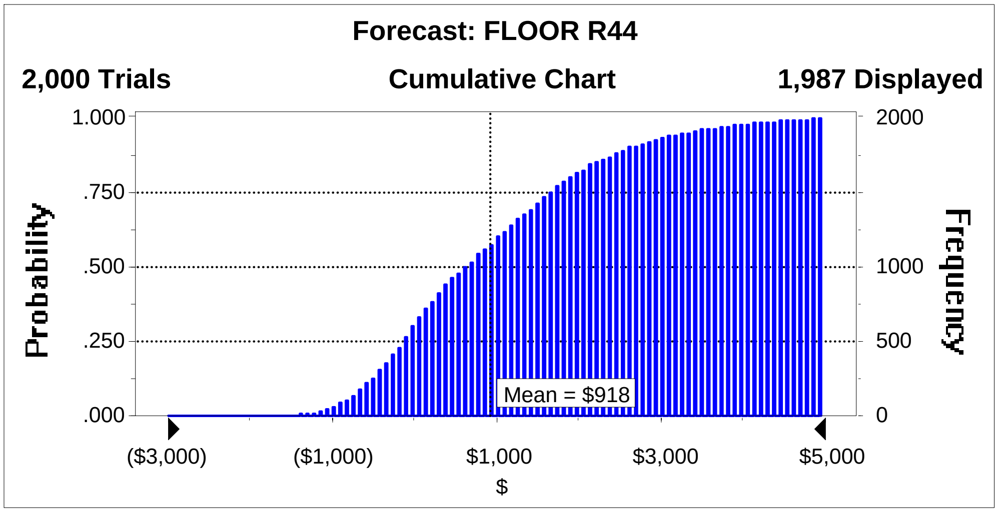


**Figure G-175: Climate Zone 1 Net Present Value Results for Manufactured Homes for R44 Floors**

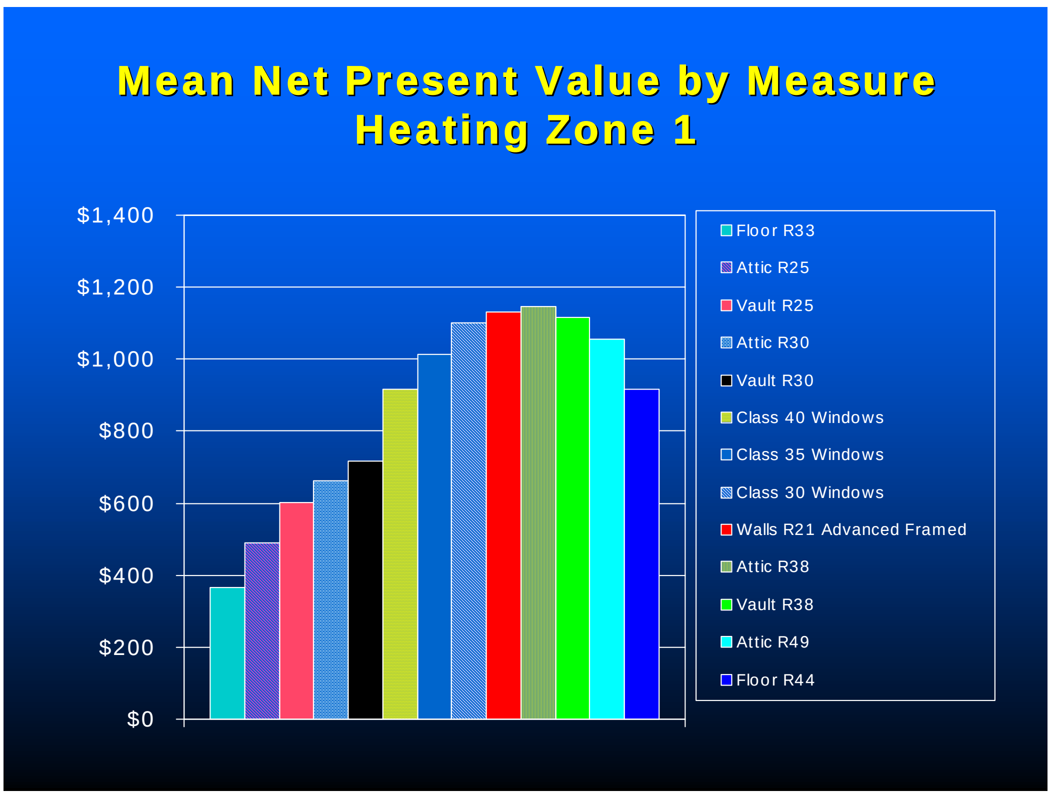


**Figure G-176: Climate Zone 1 Expected Value Mean Net Present Value Results for Manufactured Homes**

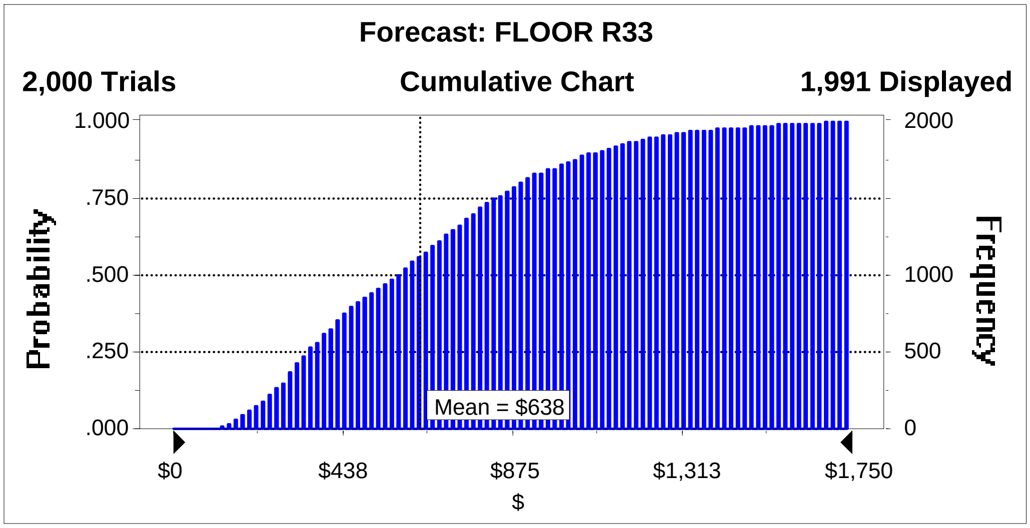


**Figure G-177: Climate Zone 2 Net Present Value Results for Manufactured Homes for R33 Floors**

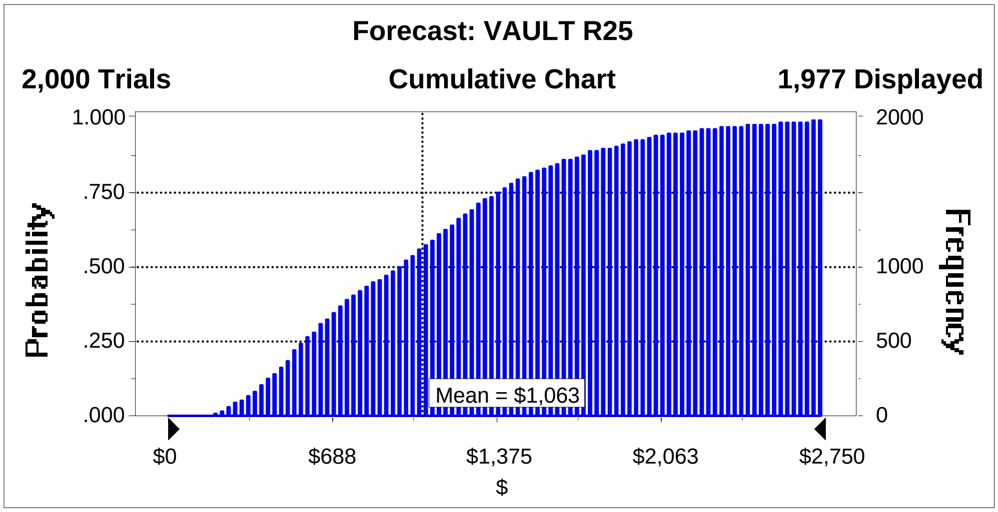


**Figure G-178: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Attics**

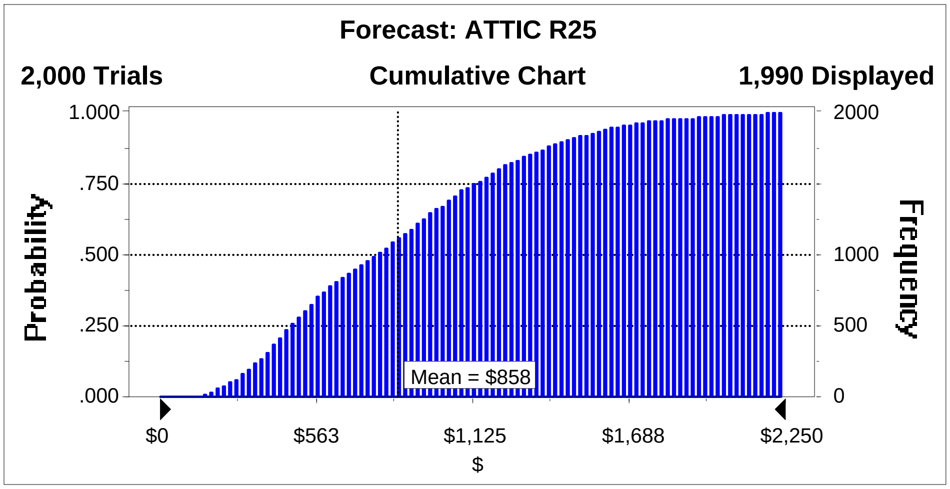


**Figure G-179: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Vaults**

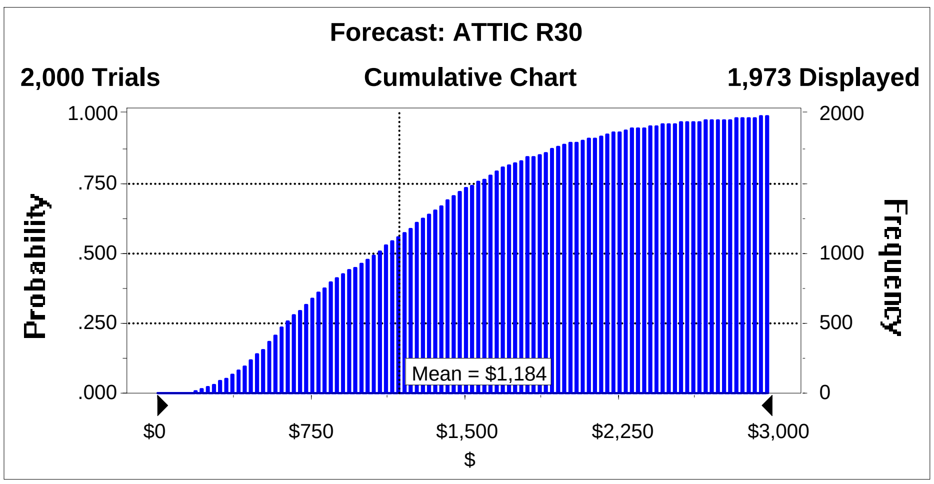


**Figure G-180: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Attics**

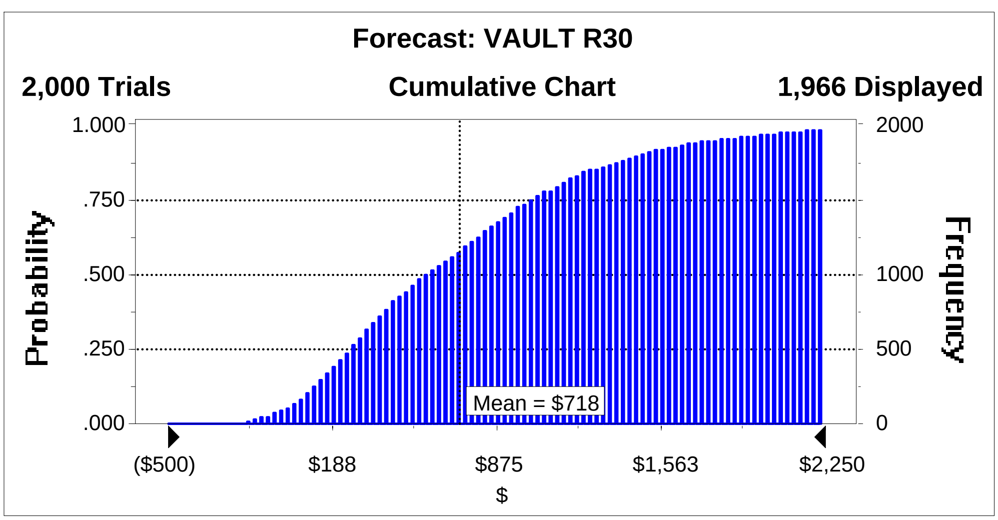


**Figure G-181: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Vaults**

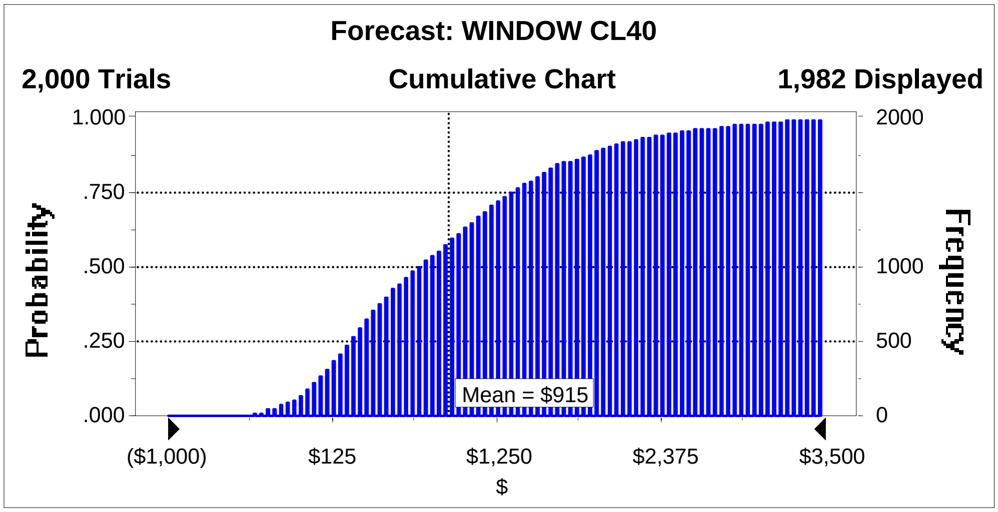


**Figure G-182: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 40 Windows**

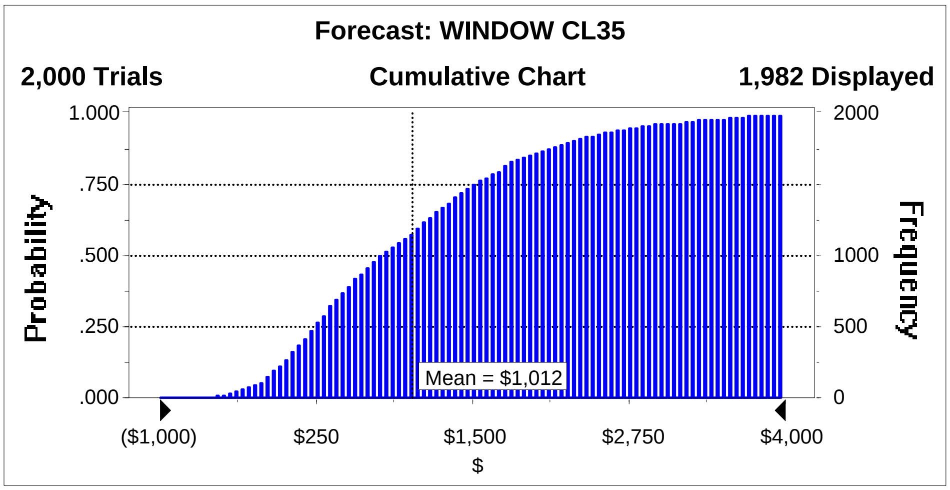


**Figure G-183: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 35 Windows**

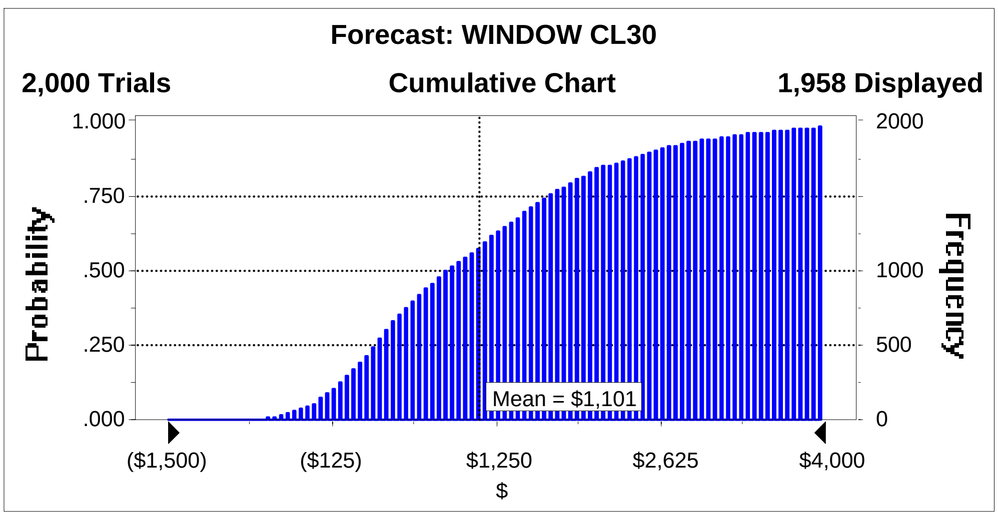


**Figure G-184: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 30 Windows**

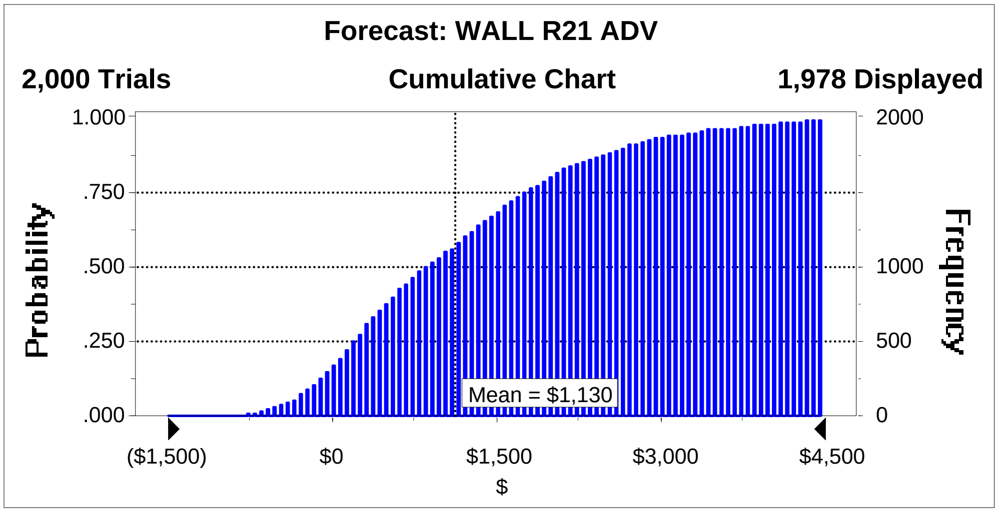


**Figure G-185: Climate Zone 2 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls**

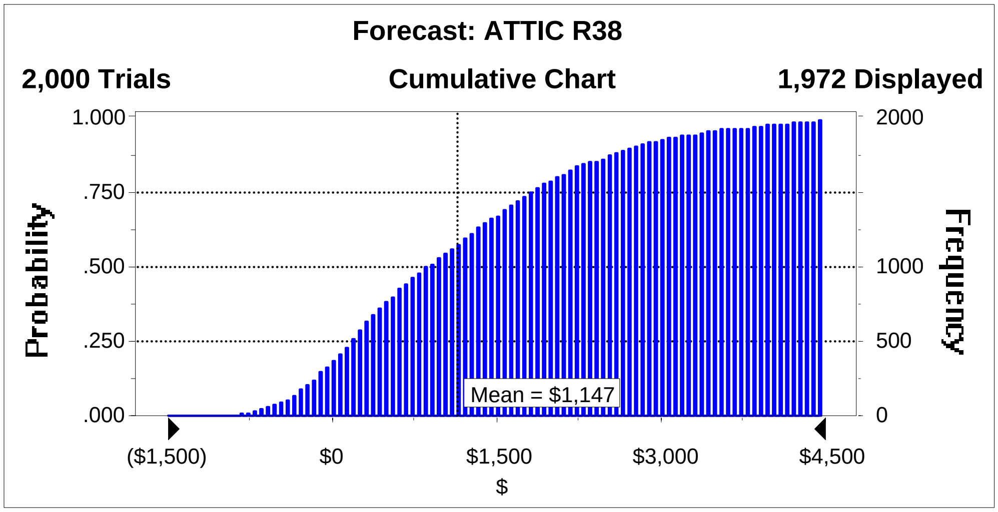


**Figure G-186: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Attics**

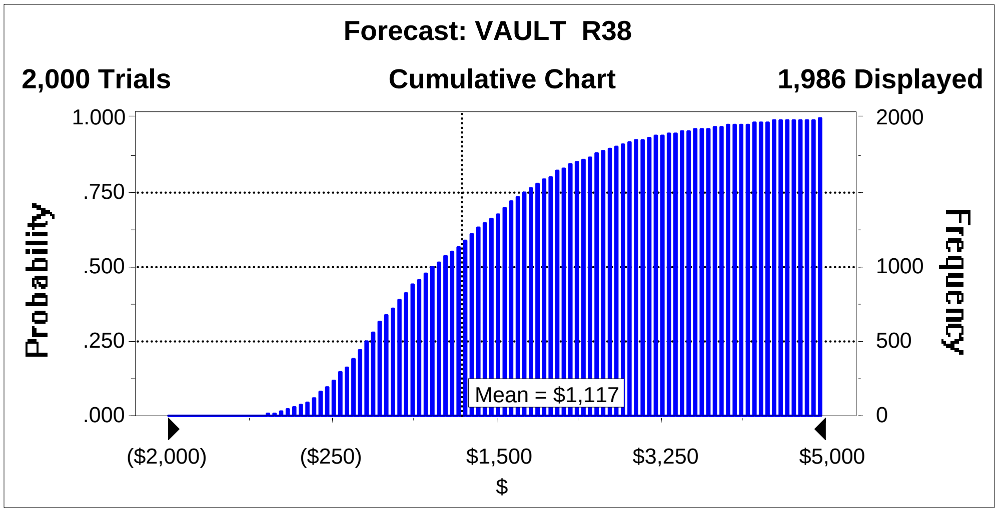


**Figure G-187: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Vaults**

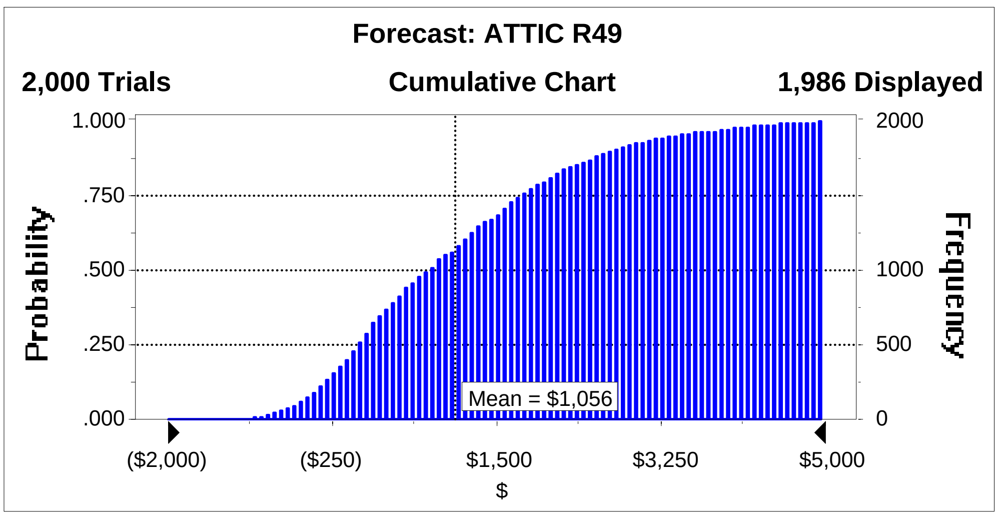


**Figure G-188: Climate Zone 2 Net Present Value Results for Manufactured Homes for R49 Attics**

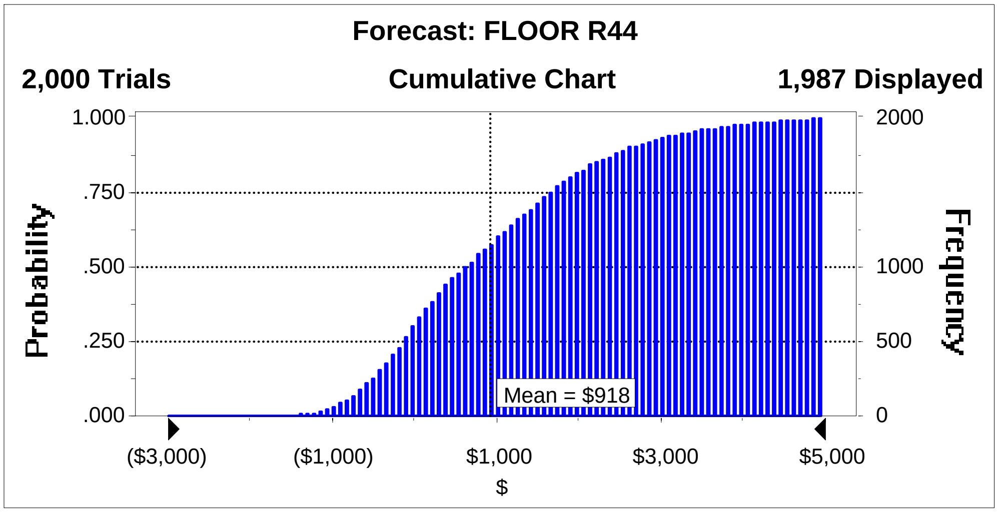


Figure G-189: Climate Zone 2 Net Present Value Results for Manufactured Homes for R44 Floors

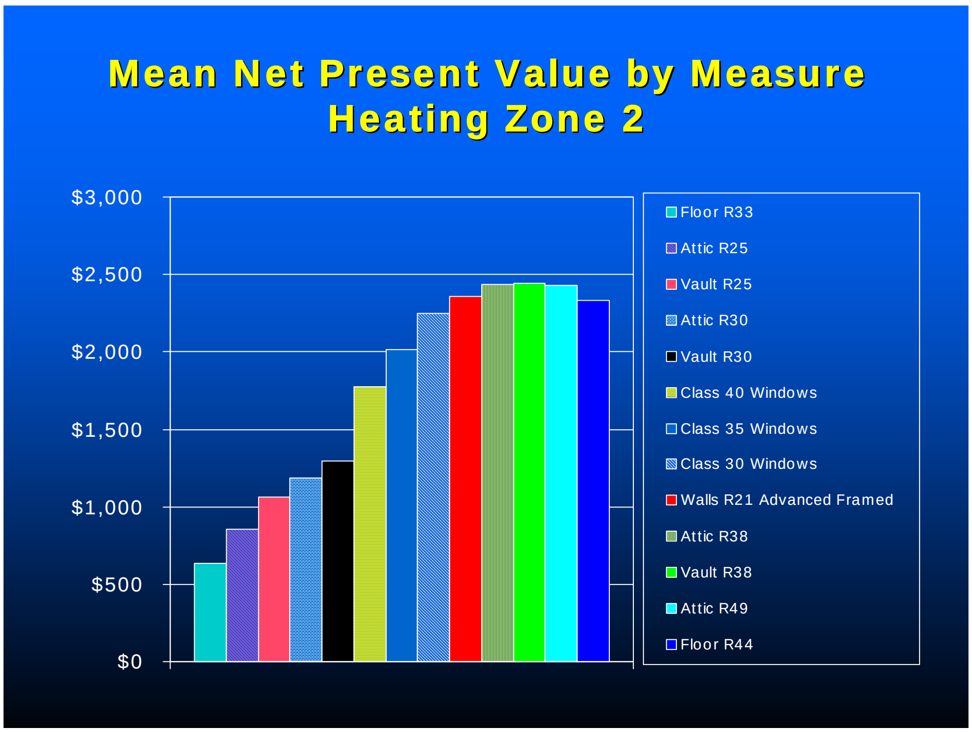


Figure G-190: Climate Zone 2 Expected Value Mean Net Present Value Results for Manufactured Homes

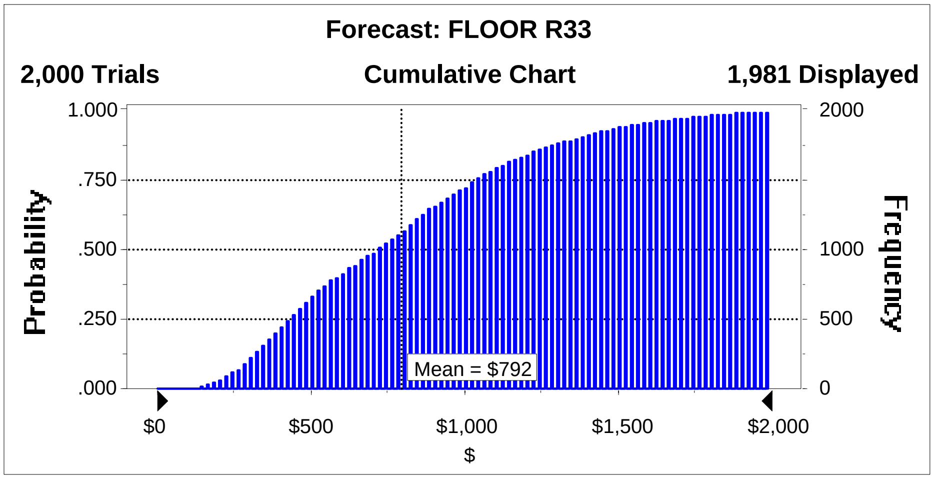


Figure G-191: Climate Zone 3 Net Present Value Results for Manufactured Homes for R33 Floors

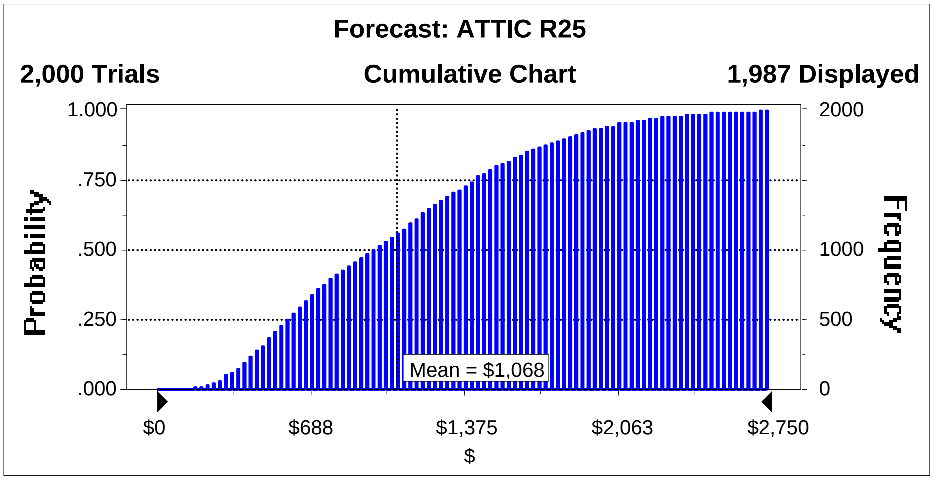


Figure G-192: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Attics

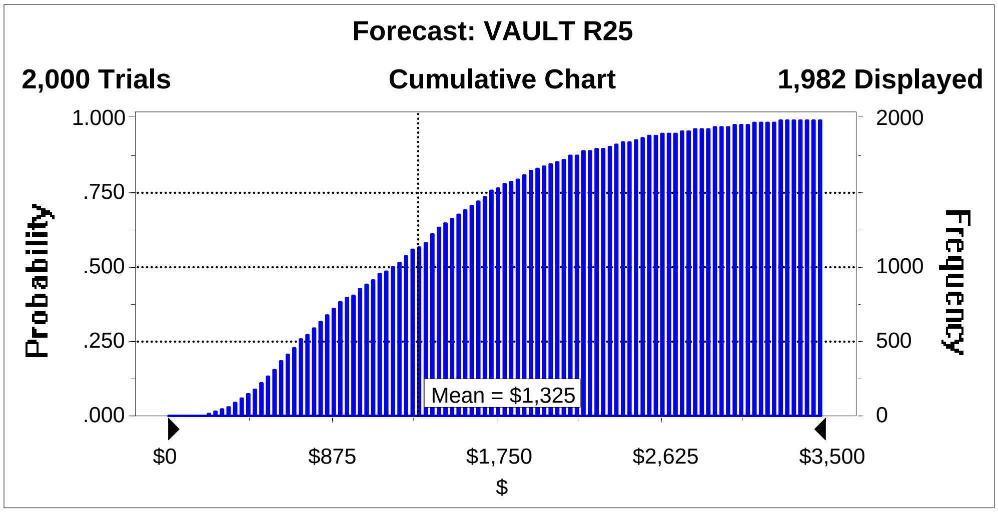


Figure G-193: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Vaults

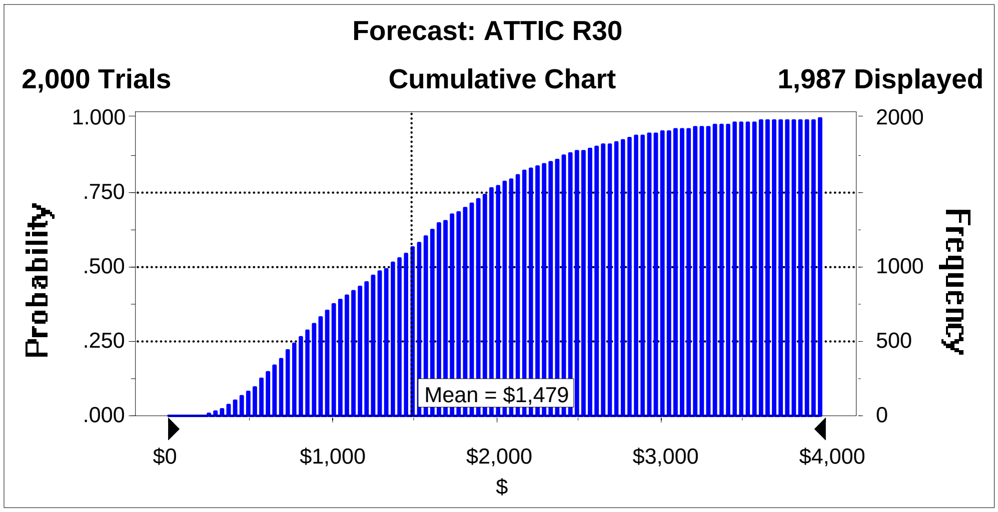


**Figure G-194: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Attics**

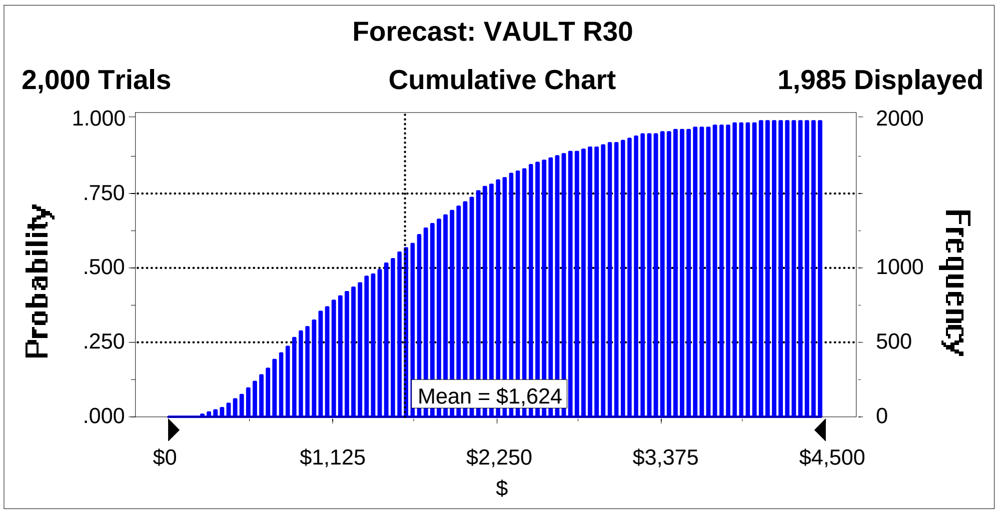


**Figure G-195: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Vaults**

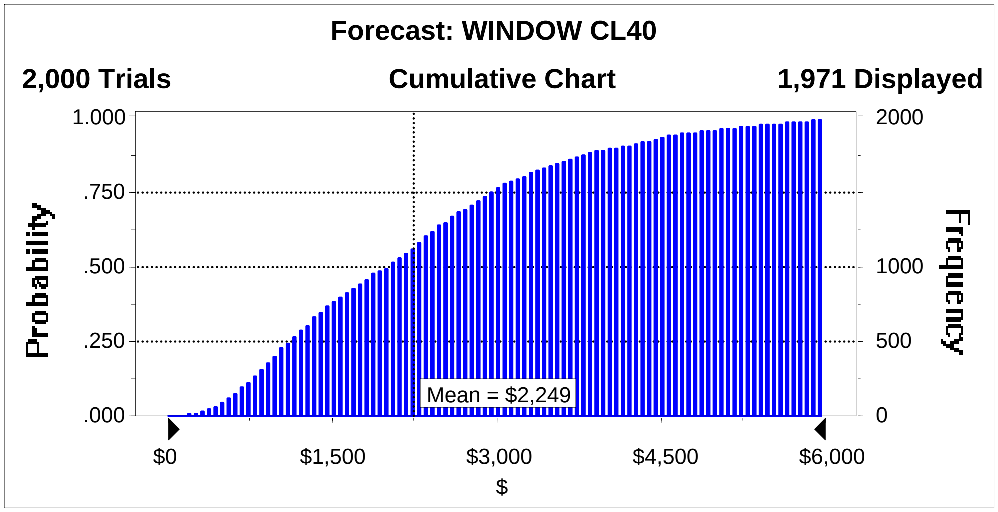


**Figure G-196: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 40 Windows**

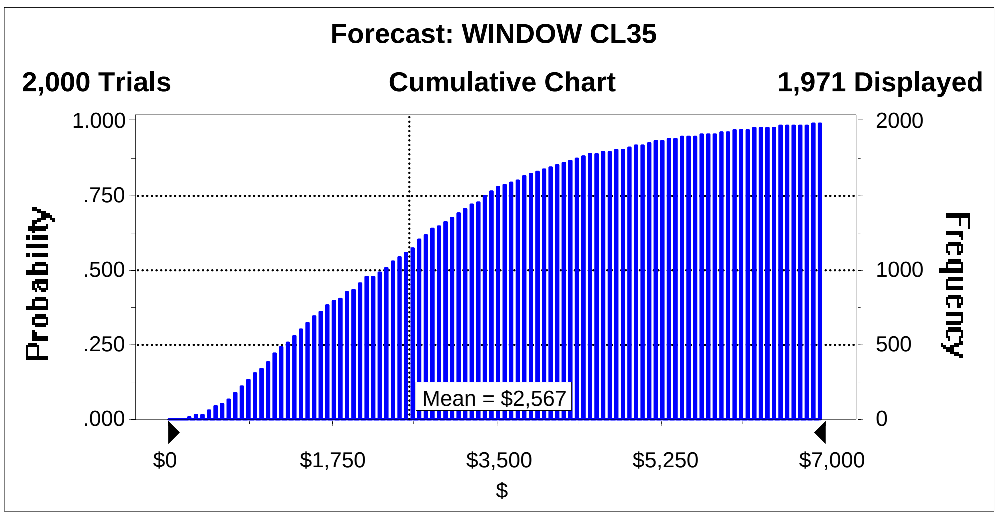


**Figure G-197: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 35 Windows**

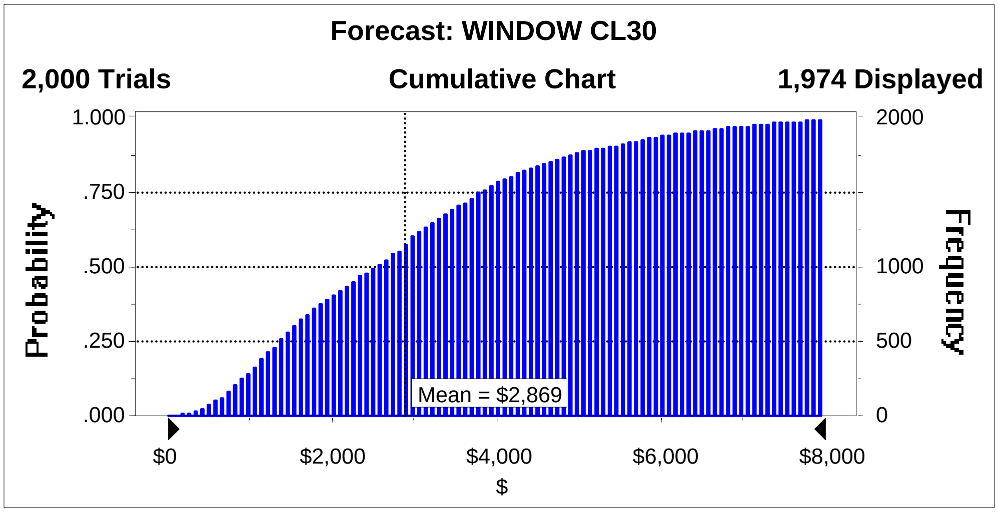


**Figure G-198: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 30 Windows**

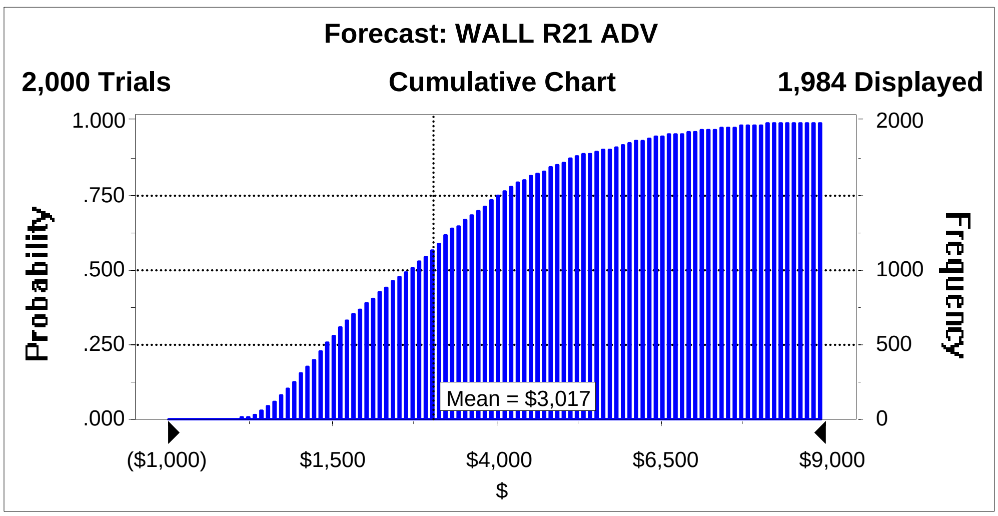


**Figure G-199: Climate Zone 3 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls**

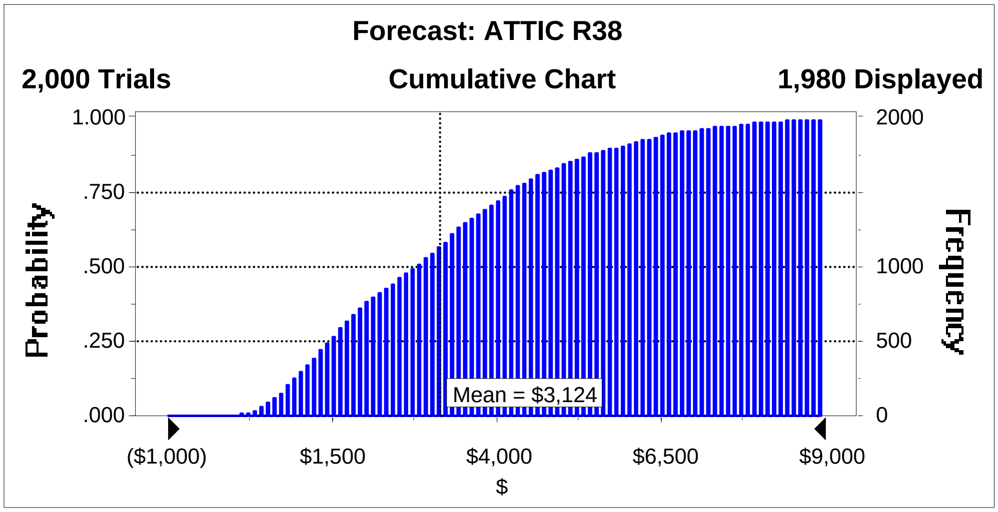


**Figure G-200: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Attics**

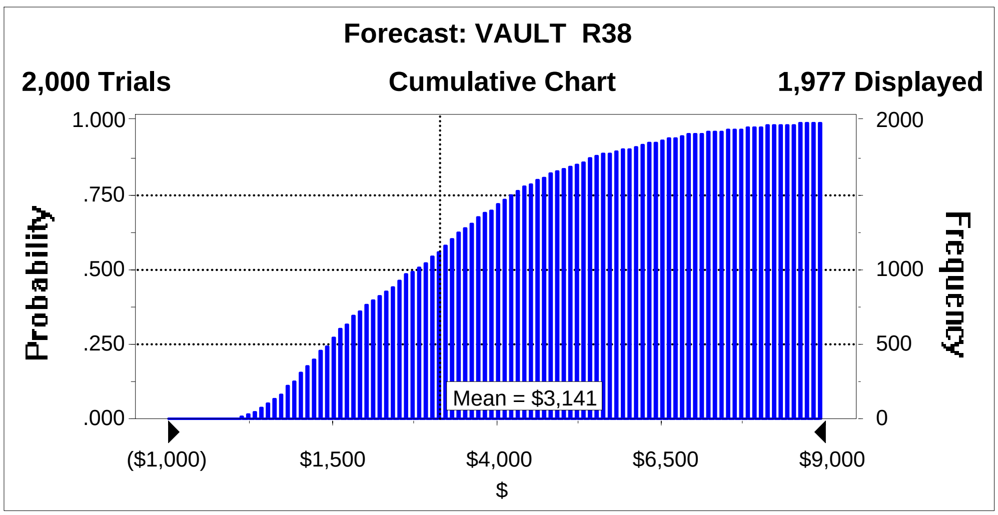


**Figure G-201: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Vaults**

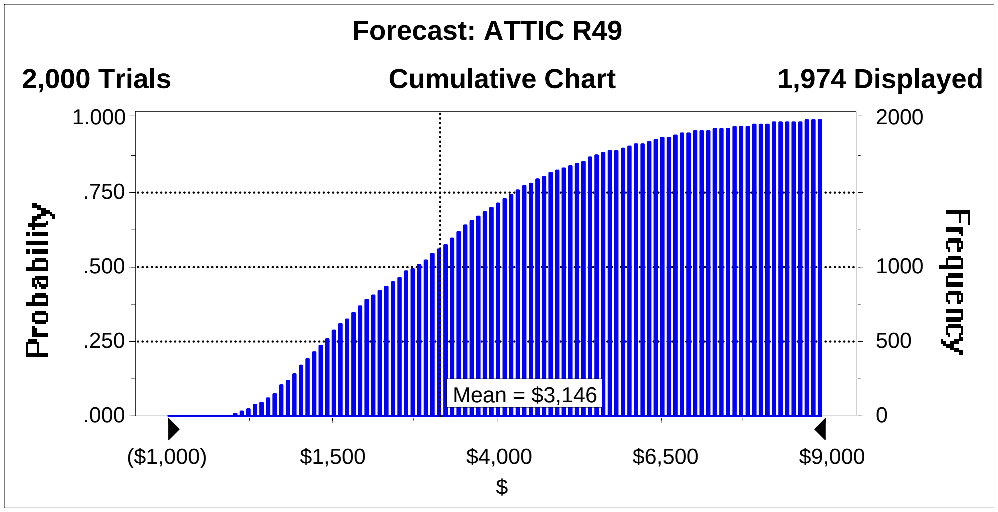


**Figure G-202: Climate Zone 3 Net Present Value Results for Manufactured Homes for R49 Attics**

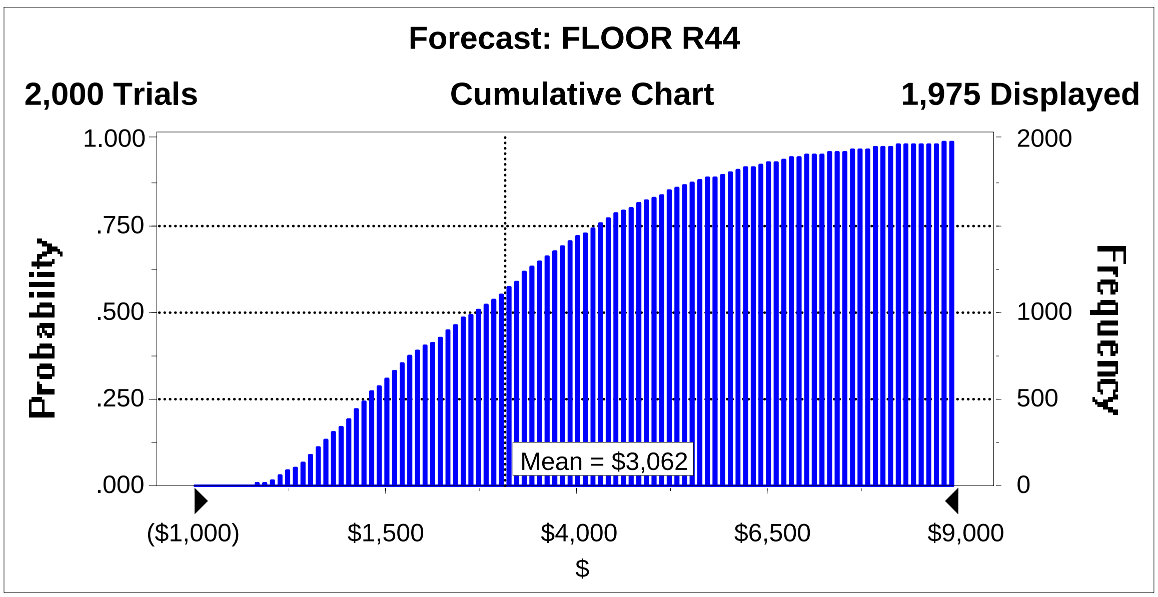


**Figure G-203: Climate Zone 3 Net Present Value Results for Manufactured Homes for R44 Floors**

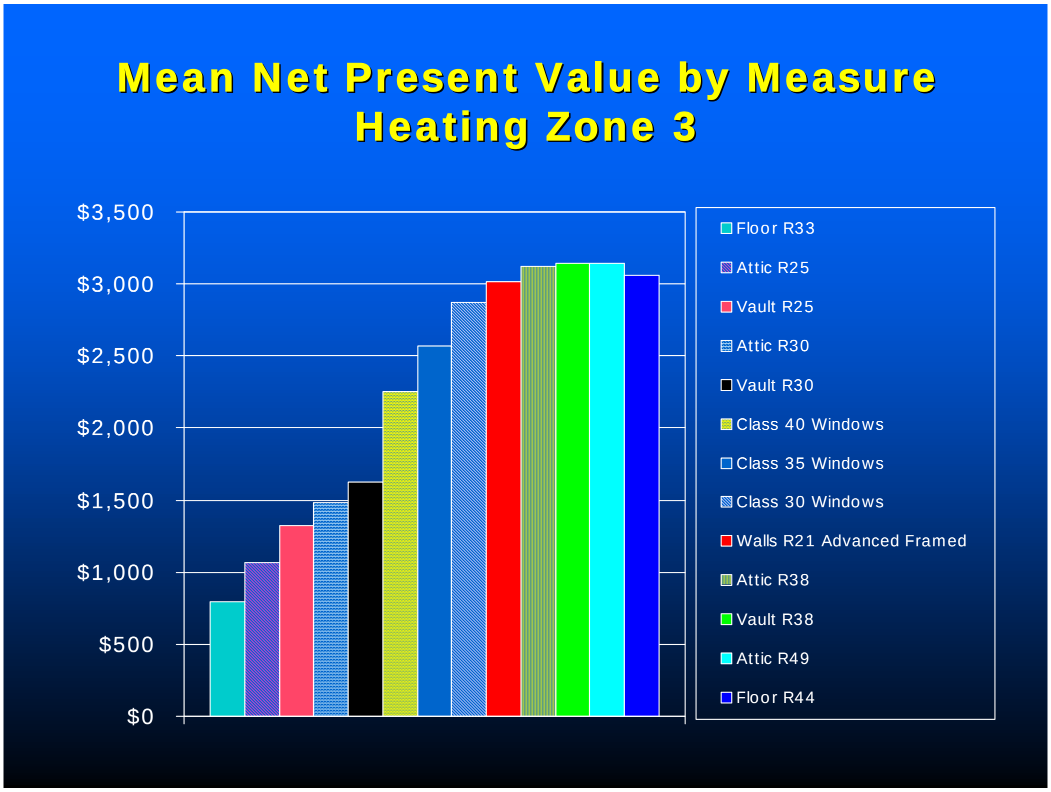


**Figure G-204: Climate Zone 3 Expected Value Mean Net Present Value Results for Manufactured Homes**

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# Demand Response Assessment

## INTRODUCTION

This appendix provides more detail on some of the topics raised in Chapter 4, "Demand Response" of the body of the Plan. These topics include

1. The features, advantages and disadvantages of the main options for stimulating demand response (price mechanisms and payments for reductions)
2. Experience with demand response, in our region and elsewhere
3. Estimates of the potential benefits of demand response to the power system

## PRICE MECHANISMS

### Real-time prices

The goal of price mechanisms is the reflection of actual marginal costs of electricity production and delivery in retail customers' *marginal* consumption decisions. One variation of such mechanisms is "real-time prices" -- prices based on the marginal cost of providing electricity for each hour. This does not mean that every kilowatt-hour customers consume needs to be priced at marginal cost. But it does mean that consumers need to face the same costs as the power system for their *marginal* use.

Real-time prices, if we can devise variations that are acceptable to regulators and customers, have the potential to reach many customers. Real-time prices can give these customers incentives that follow wholesale market costs very precisely every hour. Once established, real-time prices avoid the transaction costs of alternative mechanisms. For all of these reasons, the potential size of the demand response from real-time prices is probably larger than other mechanisms.

However, real-time prices have not been widely adopted for a number of reasons:

1. Most customers would need new metering and communication equipment in order to participate in real-time pricing. Currently, most customers' meters are only capable of measuring total use over the whole billing period (typically a month). Real-time prices would require meters that can measure usage in each hour. Also, some means of communicating prices that change each hour would be required. It's worth noting that more capable meters are also necessary for alternatives such time-of-use metering, and for such programs as short term buybacks and demand side reserves.
2. Currently, there is no source of credible and transparent real-time wholesale prices for our region. Any application of real-time retail prices will need all parties' trust that the prices are fair representations of the wholesale market. The hourly prices from the California PX were used as the basis for some deals in our region until the PX was closed in early 2001, but prices from a market outside our region were regarded as less-than-ideal even while they were still available. Now the Cal PX is closed, and a credible

regional source is needed. This is a problem that affects many of the other mechanisms for demand response[1] as well.

3. Some customers and regulators are concerned that real-time prices would result in big increases in electricity bills. While the argument can be made that such increases would be useful signals to consumers[2], the result could also be big decreases in bills. In either case, however, many customers and regulators are concerned with questions of unfair profits or unfair allocation of costs if real-time prices are adopted. The Council shares this concern.
4. Even if price increases and decreases balance over time, the greater volatility of real-time prices is a concern. Customers are concerned that more volatile prices will make it hard for them to plan their personal or business budgets. Regulators are concerned that more volatile prices will make it a nightmare to regulate utilities' profits at just and reasonable levels. The volatility is moderated if the real-time pricing applies only to marginal consumption, but it is still greater than consumers are used to.
5. Some states' utility regulation legislation constrains the definition of rates (e.g. rates must be numerically fixed in advance, not variable based on an index or formula).

With time, some of these issues can probably be solved, making real-time prices more practical and more acceptable to customers and regulators. For example:

Metering and communication technology has improved greatly. New meters not only offer hourly metering and two-way communication but also other features, such as automatic meter reading and the potential for the delivery of new services, that may make their adoption cost-effective.

Customers and regulators' concerns with fairness and volatility may be relieved by such variations of real-time prices as the Georgia Power program. That program applies real-time prices to <u>increases</u> or <u>decreases</u> from the customer's base level of use, but applies a much lower regulated rate to the base level of use itself. Compared to application of real-time prices to the total use of the customer, this variation reduces the volatility of the total bill very significantly.

Concerns with fairness may also moderate, as it is better understood that "conventional" rates have their own problems with fair allocation of costs among customers.

## Time-of-use prices

We could think of "time-of-use prices" -- prices that vary with time of day, day of the week or seasonally -- as an approximation of real-time prices. Time-of-use prices are generally based on the expected average costs of the pricing interval (e.g. 8 a.m. to 6 p.m. January weekdays).

While time-of-use prices, like real-time prices, require meters that measure usage over subintervals of the billing period, they have some advantages over real-time prices. A significant advantage of time-of-use rates is that customers know the prices in advance (usually for a year or

[1] For example, participation in short term buyback programs is enhanced when customers have confidence that their payments are based on a price impartially determined by the wholesale market rather than simply a payment the utility has decided to offer.

[2] For example, bills might rise for those customers whose use is concentrated in hours when power costs are high. While those customers would be unhappy about the change, their increased bills could be seen as an appropriate correction of a traditional misallocation of the costs of supplying them -- traditional rates shifted some of the cost of their service to other customers. Real-time prices would also increase the bills of all customers in years like 2000-2001, when wholesale costs for all hours went up dramatically. While customers are never happy to see bills rise, the advantage of such a <u>prompt</u> rise in prices would be a similarly prompt demand response, reducing overall purchases at high wholesale prices. This is a better result than the alternative of raising rates <u>later</u> to recover the utilities' wholesale purchase costs, after the costs have already been incurred.

more). This avoids the necessity of communication equipment to notify customers of price changes. It also makes bills more predictable, which is desirable to many customers and regulators.

A significant disadvantage, compared to real-time prices, is that prices set months or years in advance cannot do a very good job of reflecting the real-time events (e.g. heat waves, droughts and generator outages) that determine that actual cost of providing electricity. As a result, time-of-use pricing as it has usually been applied cannot provide efficient price signals at the times of greatest stress to the power system, when customers' response to efficient prices would be most useful.

"Critical peak pricing" is a variant of time-of-use pricing that could be characterized as a hybrid of time-of-use and real-time pricing. This variant leaves prices at preset levels, but allows utilities to match the timing of highest-price periods to the timing of shortages as they develop; these variations provide improved incentives for demand response.

Time-of-use prices will affect customers differently, depending on the customers' initial patterns of use and how much they respond to the prices by changing their patterns of use. While customers whose rates go up will be inclined to regard the change as unfair, regulators can mitigate such perceptions with careful rate design and making a clear connection between cost of service and rates.

## PAYMENTS FOR REDUCTIONS

Given the obstacles to widespread adoption of pricing mechanisms, utilities have set up alternative ways to encourage load reductions when supplies are tight. These alternatives offer customers payments for reducing their demand for electricity. In contrast with price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers". Utilities have offered to pay customers for reducing their loads for specified periods of time, varying from hours to months or years.

### Short-term buybacks

Short-term programs can be thought of as mostly load shifting (e.g. from a hot August afternoon to later the same day). Such shifting can make investment in a "peaking" generator[3] unnecessary. The total amount of electricity used may not decrease, and may even increase in some cases, but the overall cost of service is reduced mostly because of reduced investment in generators and the moderating effect on market prices. Short-term programs can be expected to be exercised and have value in most years, even when overall supplies of energy are plentiful.

Generally, utilities establish some standard conditions (e.g. minimum size of reduction, required metering and communication equipment, and demonstrated ability to reduce load on schedule) and sign up participants before exercising the program. Then, one or two days before the event:

1. The utility communicates (e.g. internet, fax, phone) to participating customers the amount of reduction it wants and the level of payment it is offering.
2. The participants respond with the amount of reduction they are willing to contribute for this event.

[3] A generator that only runs at peak demands and is idle at other times.

3. The utility decides which bids to accept and notifies the respondents of their reduction obligation.
4. The utility and respondents monitor their performance during the event, and compensation is based on that performance.

Generally participants are not penalized for not responding to an offer. However, once a participant has committed to make a reduction there is usually a penalty if the obligation is not met.

Both BPA and PGE regarded their Demand Exchange programs as successful. Between the two programs, participating customers represented nearly 1,000 megawatts of potential reductions. Actual reductions sometimes exceeded 200 megawatts.

As the seriousness of the supply shortage of the 2000-2001 period became clearer, the participation in both utilities' Demand Exchange programs declined, but largely because customers who had been participating negotiated longer-term buybacks instead.

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

## Longer-term buybacks

Longer-term programs, in contrast to short-term buybacks, generally result in an overall reduction of electricity use. They are appropriate when there is an overall shortage of electricity, rather than a shortage in peak generating capacity.

Most utility systems, comprised mostly of thermal generating plants, hardly ever face this situation. If they have enough generating capacity to meet their peak loads, they can usually get the fuel to run the capacity as much as necessary. The Pacific Northwest, however, relies on hydroelectric generating plants for about two-thirds of its electricity. In a bad water year we can find ourselves with generating capacity adequate for our peak loads, but without enough water (fuel) to provide the total electricity needed.

This was the situation in 2000-2001, and the longer-term buybacks that utilities negotiated with their customers were reasonable responses to the situation. We faced an unusually bad supply situation in those years, however. We shouldn't expect to see these longer term buybacks used often even here in the Pacific Northwest, and hardly ever in other regions with primarily thermal generating systems.

Generally, buybacks avoid some of the problems of price mechanisms, and they have been successful in achieving significant demand response. Utilities have been able to identify and reach contract agreements with many candidates who have the necessary metering and communication capability. . The notification, bidding and confirmation processes have worked. Utilities in our region have achieved short-term load reductions of over 200 megawatts. Longer-term reductions of up to 1,500 megawatts were achieved in 2001 when the focus changed because of the energy shortages of the 2000-2001 water year.

In principle, the marginal incentives for customers to reduce load should be equivalent, but buybacks have some limitations relative to price mechanisms. Buybacks generally impose transaction costs by requiring agreement on base levels of use, contracts, notification, and explicit compensation. The transaction costs mean that they tend to be offered to larger customers or easily organized groups; significant numbers of customers are left out. Transaction costs also mean that some marginally economic opportunities will be passed--there may be times when market prices are high enough to justify some reduction in load, but not high enough to justify incurring the transaction cost necessary to obtain the reduction through a buyback.

## Demand side reserves

Another mechanism for achieving demand response is "demand side reserves," which can be characterized as options for buybacks.

The power system needs reserve resources to respond to unexpected problems (e.g. a generator outage or surge in demand) on short notice. Historically these resources were generating resources owned by the utility and their costs were simply included in the total costs to be recovered by the utility's regulated prices. Increasingly however, other parties provide reserves through contracts or an "ancillary services" market. In such cases, the reserves are compensated for standing ready to run and usually receive additional compensation for the energy produced if they are actually called to run.

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

The California Independent System Operator administers an ancillary services market that has used demand side reserves in some cases. Their early experience has been that most load cannot be treated the same as generating reserve in every detail, but that demand side reserve can be useful. Analysis of their experience is continuing.

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

## Payments for reductions -- interruptible contracts

Utilities have negotiated interruptible contracts with some customers for many years. An important example of these contracts was Bonneville Power Administration's arrangement with the Direct Service Industries (DSI), which allowed BPA to interrupt portions of the DSI load under various conditions. In the past, these contracts have usually been used to improve reliability by allowing the utility to cut some loads rather than suffer the collapse of the whole system. Those contracts were used very seldom. Now these contracts can be seen as an available response to price conditions as well as to reliability threats. We can expect that participants and utilities will pay close attention to the frequency and conditions of interruption in future contracts, and we can imagine a utility having a range of contract terms to meet the needs of different customers.

### Payments for reductions -- direct control

A particularly useful form of interruptible contract gives direct control of load to the utility. Part of BPA's historical interruption rights for DSI loads was under BPA direct control. Not all customers can afford to grant such control to the utility. Of those who can, some may only be willing to grant control over part of their loads. Direct control is more valuable to the utility, however, since it can have more confidence that loads will be reduced when needed, and on shorter notice. Advances in technology could mean expansion of direct control approaches. The ability to embed digital controls in residential and commercial appliances and equipment make it possible to, for example, set back thermostats somewhat during high cost periods. While the individual reductions are small, the aggregate effect can be large. Consumers typically have the ability to override the setbacks. Puget Sound Energy carried out a limited test of controlling thermostat setback. Most consumers were unaware that any setback had occurred. The adoption of advanced metering technologies for other reasons will facilitate the use of direct control.

## SUMMARY OF ALTERNATIVE MECHANISMS

Table H-1 summarizes the alternative mechanisms and some of their attributes. Staff has offered subjective evaluations of each mechanism to stimulate comment and discussion.

**Table H-1: Types of Demand Response Programs and Attributes**

| Type of Program | Primary Objective: Capacity or Energy? | Time span | Size of Potential Resource | Flexible for Customer? | Flexible for Utility? | Predictable, Reliable Resource for Utility? |
|---|---|---|---|---|---|---|
| Real-time Prices | Both | One hour to several hours | +++ (depending on extent applied) | ++ | ++ | - |
| Time-of-use Prices | Capacity | Several hours | ++ | ++ | -- | - |
| Short Term Buybacks | Capacity | Several hours (possibly more) | ++ | ++ | + | + (once customer committed) |
| Long Term Buybacks | Energy | Several months | + | -- | -- | +++ |
| Standing Offer (e.g. 20/20) | Energy | Several months | + | ++ | -- | - |
| Demand side reserves | Capacity | Hours or longer | + | ++ | ++ | + |
| Interruptible Contracts | Capacity | Hours or longer | + | -- | ++ | ++ |
| Direct Control | Capacity | Minutes, Hours or longer | + | --- | +++ | +++ |

For example, staff's evaluation suggests that time-of-use prices:

- have significant potential for load reduction, but somewhat less than real-time prices;
- have the primary objective of reducing capacity requirements;
- are flexible for the customer -- the customer can decide how to respond depending on his real time situation;
- are relatively inflexible for the utility -- it is committed to the price structure in advance for an extended period;
- is not a very predictable resource for the utility – customers' response may vary from one day to the next (although more experience may help the utility predict that response more accurately).

Or, long term buybacks:

- have significant potential for load reduction, but less than time-of-use prices;
- have the primary objective of reducing energy requirements;
- are relatively inflexible for both customer and utility (because they are both committed to the terms of the buyback over a long term)
- are a predictable resource for the utility (once the contract is signed).

## EXPERIENCE

Experience with demand response is growing constantly, so that any attempt to describe it comprehensively is likely to be incomplete and is certain to go out of date quickly. Rather than attempt a comprehensive account, this section presents a number of significant illustrations of experience around the U.S.

## RTP Experience

### Georgia Power

Georgia Power has 1,700 customers on real-time prices. These customers, who make up about 80 percent of Georgia Power's commercial and industrial load (ordinarily, about 5,000 megawatts), have cut their load by more than 750 megawatts in some instances. The program uses a two-part tariff, which applies real-time prices to increases or decreases from the customer's base level of use, but applies a much lower regulated rate to the base level of use itself. As a result, the total power bills don't vary in proportion to the variation of the real-time prices, but customers do have a "full strength" signal of the cost of an extra kilowatt-hour of use (and symmetrically, the value of a kilowatt-hour reduction in use).

### Duke Power

Duke Power has a similar two-part tariff that charges real-time prices to about 100 customers with about 1,000 megawatts of load. Duke has observed reductions of 200 megawatts in these customers' load in response to hourly prices above 25 cents per kilowatt-hour.

### Niagara Mohawk

Niagara Mohawk has a one-part real-time price tariff that charges real-time prices for all use of its largest industrial customers. More than half of the utility's original customers in this class have moved to non-utility suppliers, and many of those remaining have arranged hedges to reduce their vulnerability to volatility of real-time prices.

## Critical Peak Pricing Experience

### Gulf Power

Gulf Power offers a voluntary program for residential customers that includes prices that vary by time of day along with a programmable control for major electricity uses (space heating and cooling, water heating and pool pump, if present). While this program mostly falls in the "time-of-use pricing" category to be described next, it has an interesting component that is similar to real-time pricing--"Critical" price periods:

The Critical price (29 cents per kilowatt-hour) is set ahead of time, like the Low (3.5 cents), Medium (4.6 cents) and High (9.3 cents) prices, but unlike the other prices, the hours in which the Critical price applies are not predetermined. The customer knows that Critical price periods will total no more than 1 percent of the hours in the year, but not when those periods will be, until 24 hours ahead of time. Gulf Power helps customers program their responses to Critical periods ahead of time, although they can always change their response in the event.

Customers appear very satisfied by this Gulf Power program. Customers in the program reduced their load 44 percent during Critical periods, compared to a control group of nonparticipants.

## TOU Experience

### The Pacific Northwest

Puget Sound Energy offered a time-of-use pricing option for residential and commercial customers. There are about 300,000 participants in the program. PSE's analysis indicates that this program reduced customers' loads during high costs periods by 5-6 percent. However, analysis showed that most customers paid slightly more under time-of-use pricing than they would have under conventional rates. PSE has ended the program, though a restructured program might be proposed later if careful analysis suggests it would be effective.

In Oregon, time-of-use pricing options have been offered to residential customers of Portland General Electric and PacifiCorp since March 1, 2002. So far about 2,800 customers have signed up, and early measures of satisfaction are encouraging, but data are not yet available on any changes in their energy use patterns.

### California

Time of use rates are now required for customers larger than 200 kilowatts, and critical peak pricing is available for those customers. The effect of the critical peak prices on customers who have selected that option is estimated to provide a load reduction potential of about 16 megawatts in 2004.

A pilot program testing the effectiveness of critical peak pricing for residential customer is completing its second year. Analysis of the first year's experience estimated own price elasticities of peak demand in the –0.1 to –0.4 range, similar to the results of the Electric Power Research Institute study described below.

There have been many other time-of-use pricing programs elsewhere in the U.S. Rather than describe a number of examples, it should suffice to say that a study funded by the Electric Power Research Institute concluded that 25 years of studies indicated that "peak-period own-price elasticities range from -0.05 to -0.25 for residential customers, and -0.02 to -0.10 for commercial and industrial customers." Stripped of the jargon, this means that a time-of-use rate schedule that increases peak period rates by an assumed 10 percent would lead to a 0.5 to 2.5 percent reduction in residential peak use, and a 0.2 to 1.0 percent reduction in commercial and industrial peak use. While the assumed 10 percent rate increase is only illustrative, it is not exaggerated; PSE's peak time rates are about 10 percent higher than its average rates, and PGE's peak time rates are 67 percent higher than its average rates.

## Short-term Buyback Experience

The historical experience with demand response is limited, and most of it is from short-term situations of tight supply and/or high prices (i.e. episodes of a few hours in length). Therefore we'll examine the potential for short-term demand response first, and turn to longer-term demand response later.

### Pacific Northwest

B.C. Hydro offered a form of short-term buyback as a pilot program quite early -- in the winter of 1998-1999. The utility offered payment to a small group of their largest customers for reductions in load. The offer was for a period of hours when export opportunities existed and B.C. Hydro had no other energy to export. Compensation was based on a "share the benefits" principle, sharing the difference between the customers' rates and the export price equally between B.C. Hydro and the customer.

The program was exercised once during the pilot phase, realizing about 200 megawatts of reduction. The overall evaluation of the program was positive and it has been adopted as a continuing program by B.C. Hydro.

Bonneville Power Administration, Portland General Electric and some other regional utilities offered another form of short-term buyback beginning in the summer of 2000. This program was called the Demand Exchange. The Demand Exchange was mostly limited to large industrial customers who had the necessary metering and communication equipment and who had demonstrated their ability to reduce load on call. Participating customers represented over 1,000 megawatts of potential reductions, and over 200 megawatts of reductions were realized in some events.

An exception to the focus on large customers was the participation of Milton-Freewater Light and Power, a small municipal utility with about 4,000 customers. Milton-Freewater participated by controlling the use cycles of a number of their customers' residential water heaters.

### California

Investor-owned utilities in California have over 1,600 megawatts of demand response available in June 2004. Over 1,000 megawatts of that total are in interruptible contracts, with about 300 megawatts in air conditioning cycling and smart thermostat programs, about 150 megawatts in demand bidding programs and the remainder in critical peak pricing and backup generation programs.

The California Independent System Operator (CAISO) has reduced its demand response programs in recognition of the programs offered by California utilities and the California Power Authority. The CAISO continues its "Participating Load Program (Supplemental and Ancillary Services)," which includes demand reductions as a source of supplemental energy and ancillary services (non-spinning reserves and replacement reserves). In this program demand reductions are bid into the ancillary services market similarly to generators' capacity and output.

The California Power Authority offers a variant of interruptible contract, with capacity payments every month based on the customer's commitment to reduce load, and energy payments based on actual reductions when the customer is called upon to do so. In June of 2004 this program was estimated to have a demand reduction capability of over 200 megawatts.

### New York Independent System Operator

The New York Independent System Operator (NYISO) has three demand response programs, the Emergency Demand Response Program (EDRP), the Day-Ahead Demand Response Program (DADRP) and Installed Capacity Special Case Resources (ICAP SCR).[4]

The EDRP is, as the name suggests, an emergency program that is exercised "when electric service in New York State could be jeopardized." Participants are normally alerted the day before they may be called upon to reduce load; they are usually notified that reductions are actually needed at least 2 hours in advance. Participants are expected, but not required, to reduce their loads for a minimum of four hours, and are compensated at the local hourly wholesale price, or $500 per megawatt hour, whichever is higher. Reductions are calculated as the difference between metered usage in those hours and the participants' calculated base loads (CBLs), which are based on historical usage patterns.

The DADRP allows electricity users to offer reductions to the NYISO in the day-ahead market, in competition with generators. If the reduction bid is accepted, the users are compensated for reductions based on the area's marginal price. The users are obligated to deliver the reductions and are charged the higher of day-ahead or spot market prices for any shortfall in performance.

The ICAP SCR program pays qualified electricity users for their <u>commitment</u> to reduce loads if called upon during a specified period, "during times when the electric grid could be jeopardized." Users receive additional payments when they are actually called and deliver reductions, at rates up to $500 per megawatt hour. Qualified electricity users cannot participate in both the EDRP and the ICAP SCR at the same time, and ICAP SCR resources are called first.

During the summer of 2003, these NYISO programs resulted in the payment of more than $7.2 million to over 1,400 customers, who reduced their peak electricity loads by 700 megawatts.

### PJM Interconnection

PJM Interconnection is the regional transmission operator of a system that covers 8 Mid Atlantic and Midwestern states and the District of Columbia. It serves a population of about 35 million, with a peak load of about 85,000 megawatts. PJM has operated demand response programs for several years.

PJM's demand response programs are categorized as "Emergency" and "Economic" options. PJM takes bids from end-use customers specifying reduction amounts and compensation

[4] For more details, see http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response_prog.html

requirements for the next day. These bids are considered alongside bids from generators, and demand reduction bids can set the market clearing "locational marginal price" (LMP, the marginal cost of service for each zone in the system) in the same way as a generator's bid. Load reductions in their "Emergency" category are paid at each hour's LMP, or $500 per megawatt-hour, whichever is greater. Load reductions in their "Economic" category are paid the LMP less the retail rate if the LMP is less than $75 per megawatt-hour, or the whole LMP if it is higher than $75 per megawatt-hour.

PJM also has an "Active Load Management" (ALM) program that compensates customers for: allowing PJM to have direct control of some loads; committing to reduce loads to a specified level; or committing to reduce loads by a specified amount.

In total PJM demand response programs had over 2,000 megawatts of potential load reductions participating in 2003, and over 3,500 megawatts of potential load reductions in 2004.

### ISO New England

The Independent System Operator (ISO) of the New England Power Pool operates the electrical transmission system covering the 6 New England states, with a population of 14 million people and a peak load of over 25,000 megawatts. Its demand response programs had 400 megawatts of capacity in 2004, about double the capacity in 2002.

ISO New England demand response programs share some features with those of the NYISO and PJM, in that they fall into "economic" and "reliability" categories. The "economic" category is voluntary -- qualified customers[5] are notified when the next day's wholesale price is expected to be above $.10 per kilowatt-hour for some period. They can voluntarily reduce their load during that period and be compensated at the greater of the real time wholesale price, or $.10 per kilowatt-hour. Their reduction is computed based on their recent load history, adjusted for weather conditions. There is no penalty for choosing not to reduce load for these customers.

In the "reliability" category customers can commit to reducing load at the call of the ISO, and be compensated based on the capacity they have committed and the energy reduction they actually deliver when called upon. The compensation for capacity (ICAP) is based on a monthly auction. The compensation for energy is the greater of the real time price or a minimum of $.35 or $.50 per kilowatt-hour, depending on whether the customer is committed to responding in 2 hours or 30 minutes, respectively. If a customer does not deliver the committed reduction it is compensated for energy reduction based on the actual performance, but the ICAP payment is reduced to the level of delivered reduction. The ICAP payment remains at that reduced level until another load reduction event; the customer's performance in that event resets the ICAP level higher or lower.

ISO New England recently issued a request for proposals to remedy a localized shortage of generation and transmission in Southwest Connecticut. It selected a combination of resources that included demand response amounting to 126 megawatts in 2004 and rising to 354 megawatts in 2007. These resources were called on in August of 2004 and delivered over 120 megawatts within 30 minutes. In that event, roughly another 30 megawatts of load reduction were realized elsewhere in ISO New England's territory.

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[5] Customers with the ability to reduce loads by 100 kilowatts, with appropriate metering and communication equipment.

## Longer-term Buyback Experience

As high wholesale prices and the drought in the Pacific Northwest continued, utilities began to negotiate longer-term reductions in load with their customers. BPA found the largest reductions, mostly in aluminum smelters but also in irrigated agriculture. Idaho Power, PGE, the Springfield Utility Board (SUB) and the Chelan Public Utility District negotiated longer-term reductions with large industrial customers. Idaho Power, Grant County Public Utility District and Avista Utilities negotiated longer-term reductions with irrigators. The total of these buybacks varied month to month but reached a peak of around 1,500 megawatts in the summer of 2001.

There were also "standing offer" buybacks offered by several utilities in 2001. Most of these offers were to pay varying amounts for reductions compared to the equivalent billing period in 2000. The general structure of these offers was a further savings on the bill if the reduction in use was more than some threshold. For example, a "20/20" offer gave an additional 20 percent off the bill if the customers' use was less than 80 percent of the corresponding billing period in 2000. Since the customer's bill was reduced more or less proportionally to his usage already, this amounted to roughly doubling his marginal incentive to save electricity. Utilities usually reported that many customers qualified for the discounts. However, attributing causation to the standing offers vs. quick-response conservation programs many utilities were running at the same time vs. governors' appeals for reductions, etc. is very difficult.

The Eugene Water and Electric Board had a standing offer that based its incentives more directly on current market prices. From April through September of 2001, 29 of EWEB's larger customers were paid for daily savings (compared to the corresponding day in 2000) based on the daily Mid-Columbia trading hub's quotes for on-peak and off-peak energy. Customers reduced their use of electricity by an average of 14 percent, and divided a total savings of $6.5 million with the utility.

# ESTIMATES OF POTENTIAL BENEFITS OF DEMAND RESPONSE

## Potential size of resource

One way to arrive at a rough estimate of short-term demand response is to use price elasticities[6] that have been estimated based on response to real-time prices elsewhere. Though we're unlikely to rely on real-time prices, at least in the near future, the other instruments we've described can provide similar incentives[7], resulting in similar demand reductions.

Price elasticities have been estimated based on data from a number of American and other utilities. The elasticities vary from one customer group and program to another, from near zero to greater than -0.3. For example, we can assume, conservatively:

1. a -0.05 elasticity as the lower bound of overall consumer responsiveness,
2. a $60 per megawatt hour average cost of electricity divided equally between energy cost and the cost of transmission and distribution
3. a $150 per megawatt hour cost of incremental energy at the hour of summer peak demand, and

[6] Price elasticity is a measure of the response of demand to price changes -- the ratio of percentage change in demand to the percentage change in price. A price elasticity of –0.1 means that a 10 percent increase in price will cause a 1 percent decrease in demand.

[7] For example, a customer with conventional electricity rate of $0.06 per kilowatt-hour might get a buyback offer of $0.15 per kilowatt-hour in a given hour. A real-time price of $0.21 per kilowatt hour would offer a similar incentive to reduce use in that hour -- in either case he is better off by $0.21 for each kilowatt hour reduction.

4. a 30,000 megawatts regional load at that hour.

For these conditions, the amount of load reduction resulting from real-time prices would be 1,603 megawatts[8]. Actual elasticities could well be larger and actual prices seem quite likely to be higher on some occasions. In either of these cases, the load reduction would be increased.

This very rough estimate could be refined, although the basic conclusion to be drawn seems clear – even if this estimate is wrong by a factor of 2 or 3, the potential is significant, and demand response should be pursued further.

## The Value of Load Reduction (avoided cost)

The primary focus of analysis was the estimation of costs avoided by demand response. These avoided costs establish the value of demand response, and provide guidance for incentive levels in demand response programs.

We used three different approaches to the estimation of avoided cost. Each of these approaches has shortcomings, but together they suggest very strongly that development of demand response will reduce total system cost and reduce risk.

The first two of these estimates focus on the costs of meeting peak loads of a few hours' duration ("capacity problems"). These are not the only situations in which demand response can be useful, but they are the most common. These estimates address the net power system costs of serving incremental load, in a world of certainty.

If our region faced a fully competitive power market, the cost avoided by demand response would be the hourly price of power in that market. Over the long run, hourly prices at peak hours should tend to approach the fully allocated net cost of peaking generators built to serve those peak hours' loads. Even if prices are capped and the construction of peaking generators is encouraged by incentives such as capacity payment, the system costs avoided by load reductions should tend toward the net cost of a new generator. Approaches 1 and 2 estimate these net costs using contrasting methodologies.

### Approach 1: Single utility, thermal generation

Approach 1 assumes that the power system is a single utility with an hourly distribution of demands similar to the Pacific Northwest. Further it assumes that the generating system is made up of thermal generators, with marginal peaking generators that are new single cycle combustion turbines or "duct firing" additions to new combined cycle combustion turbines. The assumed costs and other characteristics of these generators are taken from The NW Power Planning Council's standard assumptions for new generating resources.[9]

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[8] Using the convention that the percentage changes in demand and price are $\ln(D_2/D_1)$ and $\ln(P_2/P_1)$, respectively, we can calculate the new demand $D_2 = \exp(-0.05*\ln(180/60) + \ln(30{,}000)) = 28{,}397$ megawatts. The reduction from the initial peak demand of 30,000 megawatts is 1,603megawatts.

[9] These assumptions are documented in the *Northwest Power Planning Council New Resource Characterization for the 5th Power Plan.* The duct firing and simple cycle combustion turbine generators cited in this paper are covered in sections on "Natural Gas Combined Cycle Gas Turbine Power Plants" and "Natural Gas Simple Cycle Gas Turbine Power Plants." These documents are available on request from the Council--contact the author.

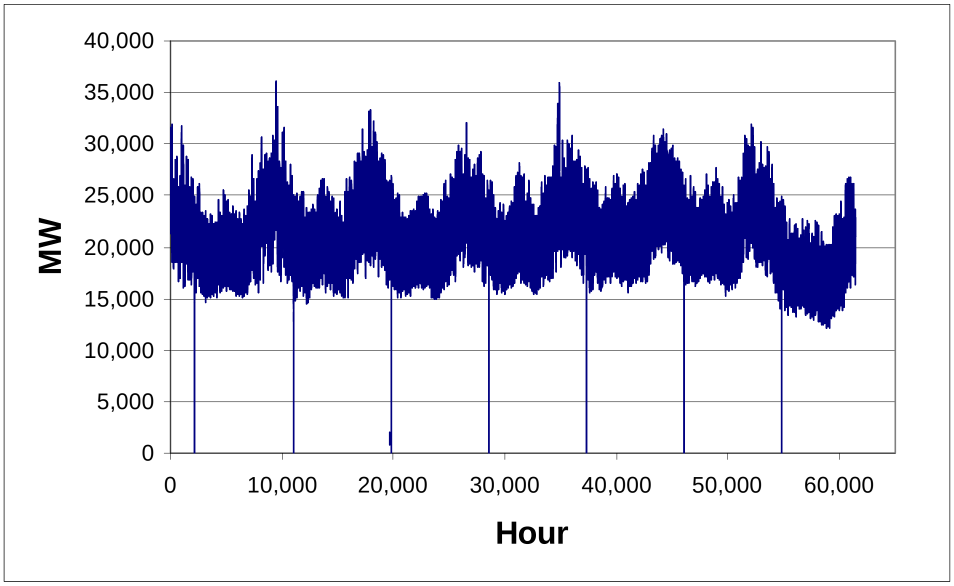


**Figure H-1: Pacific Northwest Hourly Loads 1995-2001**

In our assumed utility the cost of serving each increment of load depends on how many hours per year that load occurs. We must therefore examine the hourly distribution of loads. The Pacific Northwest hourly loads shown in Figure H-1 are loads from January 1, 1995 through December 31, 2001. The loads demonstrate that the Pacific Northwest is a winter-peaking system. The highest hourly load in the 7-year period shown is 36,118 megawatts in hour 8 of February 2, 1996 (hour 9536), and loads reach nearly 36,000 NW in several hours in December of 1998 (between hours 34,808 and 34,834). There is considerable year-to-year variation in peak loads; peak loads were below 32,000 megawatts in 1995, 1999 and 2000.

When we rearrange the same data, by ordering hourly loads from highest to lowest, we form a “load duration curve” shown in Figure H-2. Figure H-3 shows the first 700 hours in Figure 2, that is, the highest 700 hourly loads. These data let us focus on the amount of generating capacity that is used just a few hours each year to serve the highest loads.

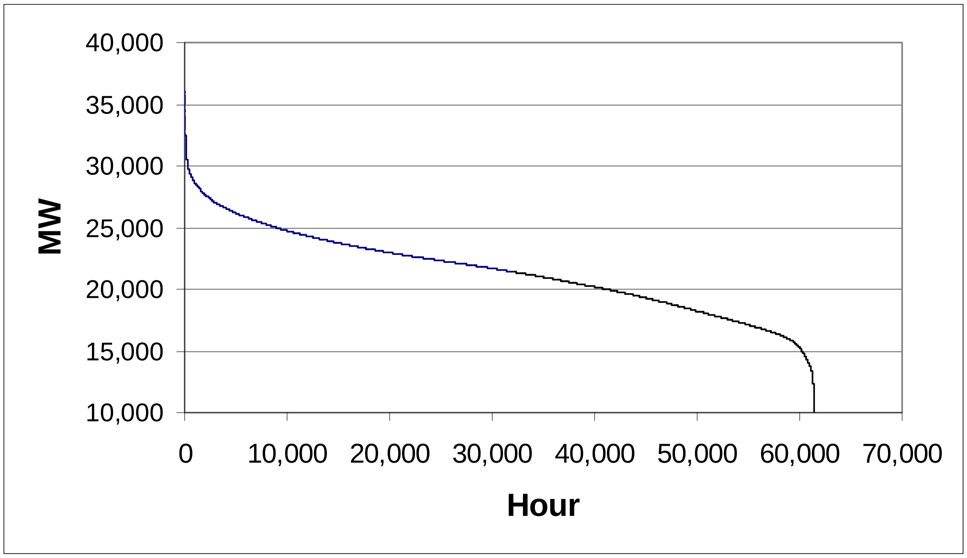


**Figure H-2: Pacific Northwest Load Duration Curve 1995-2001**

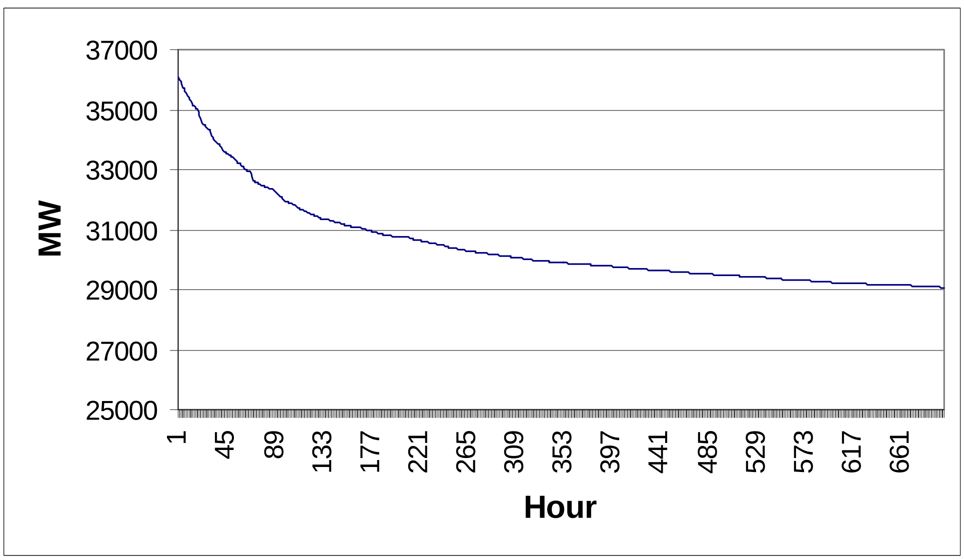


**Figure H-3: Loads of Highest 700 hours 1995-2001**

Referring to the data underlying Figure H-3, the highest load in the 7-year period is 36,118 megawatts. Of that peak load, 500 megawatts of load needs to be served only 7 hours (1 hour per year on average), 1,563 megawatts of load is served only 21 hours (3 hours per year on average), 3,500 megawatts is served 70 hours (10 hours per year on average), and so forth.

What does it cost to serve this load? Since incremental generators necessary to serve the load operate for different numbers of hours per year, each one has its own cost per megawatt-hour, declining as hours of operation per year increase. Let's look at two levels of use, 10 hours per year and 100 hours per year.

Based on the Council's generating cost data base, the cost of new[10] peaking generators used 10 hours per year is $6,489 per megawatt hour ($6.49 per kilowatt hour) for duct burner attachments on combined cycle combustion turbines, and $11,442 per megawatt hour ($11.44 per kilowatt hour) for simple cycle combustion turbines. The generators operating less than 10 hours will of course have even higher costs per megawatt-hour than these estimates.

The 700th highest hour's load in Figure 3 is 29,076 megawatts. This means that there are 3,542 megawatts of load that need to be served more than 10 hours but less than 101 hours per year. The same Council cost data cited above indicate that new peaking generators that are used 100 hours per year cost $677 per megawatt hour ($0.68 per kilowatt hour) for duct firing and $1,179 ($1.18 per kilowatt hour) for simple cycle combustion turbines. That means that serving peak loads between 29,076 megawatts and 32,618 megawatts by building and operating new peaking generators costs between $0.68 per kilowatt hour and $11.44 per kilowatt hour, depending on which type of generator is used and whether its hours of use are closer to 10 hours per year or 100 hours per year. All of these costs are much higher than retail electricity prices, which run in the $0.05-0.10 per kWh range in our region.

To summarize, the assumption of a single utility, Pacific Northwest hourly loads and new thermal resources leads to the conclusions:

1. The highest 70 hourly loads in the 1995-2001 period require about 3,500 megawatts of peaking generation to serve. Load reductions that made it unnecessary to serve these loads would save at least $6.49 per kilowatt-hour.
2. The next highest 630 hourly loads in the 1995-2001 period require about 3,542 megawatts of peaking generation to serve. Load reductions that made it unnecessary to serve these loads would save between $0.68 and $6.49 per kilowatt-hour.

### *Limitations of this analysis*

This analysis used simplifying assumptions that let us focus on the concepts involved, but excluded some features of the real world, possibly influencing the results. What assumptions deserve consideration for a more refined analysis?

#### Hydroelectric resources

The initial analysis assumed that the generating system was made up entirely of thermal resources. In fact, hydroelectric generators provide more than half of the electrical energy of the Pacific Northwest power system. Hydroelectric resources look like baseload generators in some respects--their cost structure is high capital cost/low variable cost, like nuclear plants.

But in other respects, hydro resources lend themselves to use as peaking resources. Their output can vary quickly to follow loads' short-term variation. Our hydro system was built with a lot of generating capacity to take advantage of years when more-than-normal precipitation makes more energy production possible. By using their reservoirs, hydro resources can even store energy generated by baseload thermal units and release it to meet peak loads, within limits.

Finally, the total energy available from the hydro system varies, depending on variation in seasonal and annual precipitation. In our power system a thermal peaking generator may operate

[10] Operating an existing peaking plant, once the fixed costs are incurred, is much cheaper. The greatest savings offered by demand response is as an alternative to building a new generating plant, avoiding the generator's fixed cost.

more like a baseload plant in bad water years, because of a shortage in energy from the hydro system.

These considerations make it desirable to reflect hydro resources' effects in our analysis.

### Trade between systems with diverse seasonal loads

The initial analysis assumed that generation served a single utility with an hourly distribution of loads like the Pacific Northwest. Actually, our transmission system links us to other systems (most notably California) that have different load distributions. In the real world peaking generators may very well run to meet winter peak loads in our region, and also to help meet summer peak loads in California. This would tend to increase the use of each peaking generator, spreading its fixed cost over more hours and reducing the average cost of meeting peak loads.

### Operational savings of new units

The marginal effect of a new peaking generator added to an existing system to meet peak loads is more complex than we assumed in the initial analysis. The new unit, if it is more efficient than older units, will be operated ahead of them. The result could be that the new unit is operated not just to cover growth in peak loads, but also to reduce operating costs by replacing older units' production. In this case the net cost of meeting incremental peak load is not the fixed and operating costs of the new unit, as we assumed in the initial analysis, but rather the fixed cost of the new unit minus the net operational savings that it makes possible for the system as a whole.

## Approach 2: AURORA® simulation of Western power system

The Council uses a proprietary computer model, AURORA®,[11] to project electricity prices and to simulate other effects of changes in the development and operation of the power system. AURORA® simulates the development and operation of the power system of the Western United States and Canada. It takes account of interaction between hydro and thermal generators, trade among the various regions, and the operational interaction among plants of different generating efficiencies; that is, it allows a more realistic set of assumptions than we adopted in Approach 1. We used AURORA® to refine our initial estimate of the net cost of serving incremental peak load.

Our analytical approach was to begin with the Council's baseline projection, noting the amount of electricity service that is projected by AURORA® and the generating costs of the power system. Then we varied the amount of generating capacity, and simulated the operation of the power system again, noting the changes in electricity service and generating costs. We focused on the year 2010 because we appear to have a surplus of generating capacity at the present, and by 2010 AURORA® has arrived at something like equilibrium between supply and demand.

In order to vary the amount of generating capacity, we varied the operating reserve requirements simulated by AURORA® across three levels--6.5 percent, 15 percent and 25 percent. We performed the experiment twice with the same three generating portfolios: once assuming energy output from the Pacific Northwest hydro system based on average precipitation, and again with Pacific Northwest hydro energy based on "critical" precipitation.[12]

[11] The AURORA® Energy Market Model is licensed from EPIS, Inc.

[12] "Critical" water is used in the Pacific Northwest as the basis of the energy that can be counted as "firm" from the hydro system. Critical water is based a series of bad water years in the 1930s.

The result was three levels of costs and levels of service for average water and three levels of costs and levels of service for critical water, shown in Table H-2.

**Table H-2: West-wide Change in Costs and Service from AURORA® Simulations - 2010**

| Case | Change in System Costs ($thousands) | Change in Electricity Service - megawatt hour | Cost of Change in Service<br>$ per megawatt hour ($ per kilowatt hour) |
|---|---|---|---|
| 6.5% -15% Reserve (Average Water) | 1,190,262 | 1,157,188 | 1029 (1.03) |
| 15% - 25% Reserve (Average Water) | 2,467,836 | 168,793 | 14,621 (14.62) |
| 6.5% - 15% Reserve (Critical Water) | 1,113,170 | 2,144,813 | 519 (0.52) |
| 15% - 25% Reserve (Critical Water) | 2,420,030 | 580,653 | 4,168 (4.17) |

Given that Approach 2 is much different in structure and assumptions than Approach 1, it's not surprising that the estimated costs of incremental service are different. However, both approaches show that at high levels of service the cost of serving incremental load can be well over $1,000 per megawatt hour ($1.00 per kilowatt hour). Put another way, both approaches suggest that the power system could save well over $1.00 per kilowatt-hour if it could avoid serving the highest peak loads. In both approaches the cost of serving incremental load rises as we serve the last few hours of the highest peak loads (the highest 10 hours in Approach 1, the highest operational reserves in Approach 2).

Approach 2 lets us examine the effects of variation in output from the hydroelectric system on the results. Other factors equal, overall system costs are higher when we assume critical water than when we assume average water. However, with critical water, less energy is available from the Pacific Northwest hydroelectric system and generators run more hours, spreading their fixed cost and reducing the cost of incremental service per megawatt-hour. Table H-2 doesn't show this, but the absolute levels of service are lower with critical water. The general pattern noted above, of incremental costs rising at higher operational reserves, persists with critical water.

The Council's AURORA® analysis treats the power system of the western U.S. and Canada as made up of 16 regions, with four of these regions corresponding to the Pacific Northwest. Table H-2 shows the total results of all 16 regions, but we also examined the results for the Pacific Northwest, shown in Table H-3.

**Table H-3: Pacific Northwest Change in Cost and Service from AURORA Simulations - 2010**

| Case | Change in System Costs ($thousands) | Change in Electricity Service MWh | Cost of Change in Service $ per megawatt hour ($ per kilowatt hour) |
|---|---|---|---|
| 6.5% -15% Reserve (Average Water) | -2,112 | 328,705 | -6 (-0.01) |
| 15% - 25% Reserve (Average Water) | 7,346 | 50,386 | 146 (0.15) |
| 6.5% - 15% Reserve (Critical Water) | 29,756 | 596,896 | 50 (0.05) |
| 15% - 25% Reserve (Critical Water) | 131,323 | 112,299 | 1,169 (1.17) |

These results are markedly different than the results for the whole West. The costs of incremental service shown in the last column are much lower than in Table H-2, and even include a negative cost. This seemed unreasonable at first, but after more examination of the detailed results it became clear that the Pacific Northwest added relatively less generating capacity in response to the increased reserve requirements than did the West as a whole.

This is because the heavily hydroelectric power system of the Pacific Northwest already had relatively high reserves. Our hydro system was built with such reserves to cover the variation in river flows as well as concern about serving peak load. The result is that the Pacific Northwest had to invest relatively little fixed cost to meet the 15 percent and 25 percent operational reserve. At the same time, the extra generating reserves throughout the West drove market prices of wholesale electricity down. The Pacific Northwest could reduce operational costs by taking advantage of increased opportunities to buy energy from neighboring regions. These operational cost savings partially offset (and in the "6.5% -15% Reserve (Average Water)" case, <u>more</u> than offset) the increased fixed costs due to new generator investments in the Pacific Northwest.

This example illustrates a more general issue, which is: any region (or utility) will benefit if it can depend on its neighbors' reserves while avoiding some of the fixed costs of those reserves. The temptation for each party to lean on others' reserves will tend to discourage everyone from making such investments, and tend to leave the whole system with less-than-optimal reserves.

What's the implication of this issue for demand response? Avoidance of fixed costs is the main incentive for leaning on neighbors' reserves. To the extent we can identify lower-fixed-cost alternatives to provide reserves, we reduce this incentive. To the extent that demand response comes to be seen as a proven alternative to building peaking generators, the very low fixed cost of demand response would make it less risky for each party to cover its own reserve needs, and more likely that total system reserves are adequate.

### Approach 3: Portfolio Analysis of Risk and Expected Cost

Approaches 1 and 2 estimated the avoided cost of serving known loads with known resources. In fact, loads are uncertain because we don't know future weather and economic growth, and the capability of our generating resources is uncertain because of unplanned outages, variation in rain and snowfall, among other factors. In addition, the region's utilities buy and sell into an electricity market that includes the western U.S. and Canada, making market prices a further source of uncertainty. For these and other reasons, the Council adopted a long-term portfolio analysis in formulating the Fifth Power Plan. Approach 3 used the Council's portfolio analysis model to make a third estimate of the value of demand response to the system.

The Council's portfolio methodology is described in Chapters 6 and 7 of the Plan, and in more detail in Appendix L. To evaluate the effect of demand response on risk and expected cost, the Council's portfolio model was run with and without demand response, and the resulting shift in the efficient frontier of portfolios was analyzed. This analysis was described briefly in Chapter 7.

For the "with" demand response portfolio analysis, Council staff assumed a block of 2,000 megawatts of load reduction is available by 2020, with an initial fixed cost of $5,000 per megawatt, a maintenance cost of $1,000 per megawatt per year and a variable cost of $150 per megawatt-hour when the load reduction is actually called upon.[13] The "without" demand response assumed that no demand response is available.

The portfolio model simulated 750 20-year futures with demand response available 16 years in each future. Demand response was used in 83 percent of years in which it is available, but the amount of demand response used is usually quite small. In 85 percent of the years in which demand response is used, it is used less than 0.1 percent of its capability (i.e. less than 9 hours per year). According to the portfolio model's simulations, demand response is used more than 10 percent of its capability (equivalent to about 870 hours per year) in about 5 percent of all years.

The effect of removing demand response on the efficient frontier is demonstrated in Figure H-4. The efficient frontier is shifted from the "Base Case" up and to the right to "No Demand Response," reflecting increases in both expected cost and risk. The amount of the shift varies along the frontier, but in general the loss of demand response increases expected cost by more than $300 to more than $500 million for constant levels of risk. Expressed another way, the loss of demand response increases risk in the range of $350 to $650 million at given levels of expected cost. These increases in expected cost and risk are largely due to increased purchases from the market at times of high prices and to the cost of building and operating more gas-fired generation.

[13] This assumption is simpler than reality, since the variety of load reduction opportunities mean that there is really a supply curve for demand response, with more response available at higher costs.

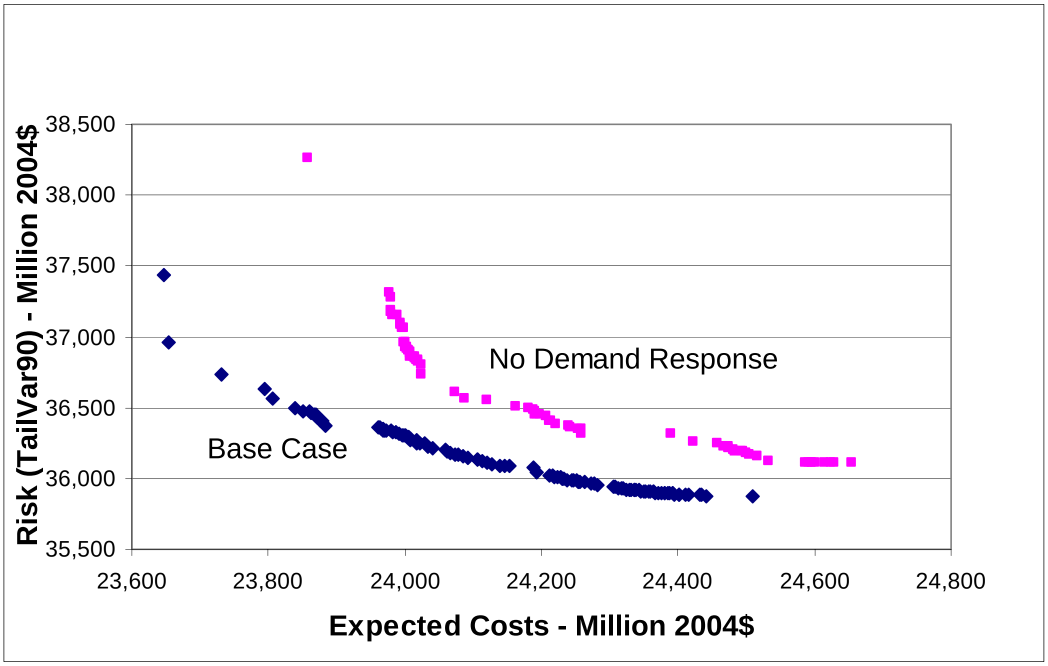


**Figure H -4: Effect of Demand Response on Efficient Frontier**

## Summary of Analysis on Value of Load Reduction

Each of the approaches to estimating the value of load reduction has its own strengths and limitations, but the general conclusions are quite robust: Demand response offers very significant potential value to the region. As laid out in Chapter 4 and in the Action Plan, there are a number of areas that need further experience and analysis in order for the region to realize that potential value, but the analysis presented here is evidence that the effort to acquire that experience and perform that analysis is very worthwhile.

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# Bulk Electricity Generating Technologies

This appendix describes the technical characteristics and cost and performance assumptions used by the Northwest Conservation and Power Council for resources and technologies expected to be available to meet bulk power generation needs during the period of the power plan. These resources and technologies are explicitly modeled in the Council's risk and reliability models and are characterized in the considerable detail required by these models. Other generating resources and technologies are described in Appendix J - Cogeneration and Distributed Generation. The intent of this appendix is to characterize typical facilities, recognizing that actual projects will differ from these assumptions in the particulars. These assumptions are used in for the Council's price forecasting, system reliability and risk assessment models, for the Council's periodic assessments of system reliability and for the assessment of other issues where generic information concerning power plants is needed.

## PROJECT FINANCING

Project financing assumptions are shown in Table I-1 for three types of possible project owners. Because the Council's plan is regional in scope, assumptions must be made regarding the expected mix of ownership for each resource. For the purpose of electricity price forecasting, the Council uses the weighted average of the expected mix of project owners for each resource type. For example, trends suggest that most wind projects will continue to be developed by independent power producers. Thus the "expected mix" for future wind capacity is 15 percent consumer-owned utility, 15 percent investor-owned utility and 70 percent independent power producer. For comparative evaluation of resources, including the portfolio analysis and the benchmark prices appearing in the plan, the Council uses a "standard" ownership mix. This consists of 20 percent consumer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer ownership. The expected mix of project owners is provided in the tables of resource modeling characteristics appearing in this appendix.

**Table I-1:** Project financing assumptions

| Developer: | Consumer-owned Utility | Investor-owned Utility | Independent Developer |
|---|---|---|---|
| **General** | | | |
| General inflation | 2.5% | | |
| Debt financing fee | 2.0% | | |
| **Project financing terms** | | | |
| Debt repayment period | 30 years | 30 years | 15 years |
| Capital amortization period | | 20 years | 20 years |
| Debt/Equity ratio | 100% | 50%/50% | Development: 0%/100%<br>Construction: 60%/40%<br>Long-term: 60%/40% |

| Developer: | Consumer-owned Utility | Investor-owned Utility | Independent Developer |
|---|---|---|---|
| Interest on debt (real/nominal) | 2.3%/4.9% | 4.7%/7.3% | Development: n/a<br>Construction: 3.9%/6.5%<br>Long-term financing: 5.2%/7.8% |
| Return on equity (real/nominal) | | 8.3/11% | 12.2/15% |
| After-tax cost-of-capital (real/nominal) | 2.3 %/4.9% | 5.0%/7.7% | 6.1%/8.9% |
| Discount Rate (real/nominal) | 2.3 %/4.9% | 5.0%/7.7% | 6.1%/8.9% |
| **Taxes & insurance** | | | |
| Federal income tax rate | n/a | 35% | 35% |
| Federal investment tax credit | n/a | 0% | 0% |
| Tax recovery period | n/a | 20 years | 20 years |
| State income tax rate | n/a | 5.9% | 5.9% |
| Property tax | 0% | 1.4% | 1.4% |
| Insurance | 0.25% | 0.25% | 0.25% |

## FUEL PRICES

The price forecasts for coal, fuel oil and natural gas are described in Appendix B.

## COAL-FIRED STEAM-ELECTRIC PLANTS

Coal-fired steam-electric power plants are a mature technology, in use for over a century. Coal is the largest source of electric power in the United States as a whole, and the second largest supply component of the western grid. Over 36,000 megawatts of coal steam-electric power plants are in service in the WECC region[1], comprising about 23 percent of generating capacity. Beginning in the late 1980s, the economic and environmental advantages of combined-cycle gas turbines resulted in that technology eclipsing coal-fired steam-electric technology for new resource development in North America. Less than 500 megawatts of new coal-fired steam electric plant has entered service on the western grid since 1990.

The prospect for coal-generated electricity is changing. The economic and environmental characteristics of coal-fired steam-electric power plants have improved in recent years and show evidence for continuing evolutionary improvement. This, plus stable or declining coal prices and high natural gas prices are reinvigorating the competition between coal and natural gas. Over 960 megawatts of new coal steam capacity are currently under construction in the WECC region.

[1] WECC is the reliability council for the western interconnected grid, extending from British Columbia and Alberta on the north to Baja California, Arizona, New Mexico and the El Paso area in the south.

## Technology

The pulverized coal-fired power plant is the established technology for producing electricity from coal. The basic components of a steam-electric pulverized coal-fired power plant include a coal storage, handling and preparation section, a furnace and steam generator and a steam turbine-generator. Coal is ground to dust-like consistency, blown into the furnace and burned in suspension. The energy from the burning coal generates steam that is used to drive the steam turbine-generator. Ancillary equipment and systems include flue gas treatment equipment and stack, an ash handling system, a condenser cooling system, and a switchyard and transmission interconnection. Environmental control has become increasingly important and newer units are typically equipped with low-NOx burners, sulfur dioxide removal equipment, filters for particulate removal and closed-cycle cooling systems. Selective catalytic reduction of NOx and CO emission is becoming increasingly common and post-combustion mercury control is expected to be required in the future. Often, several units of similar design will be co-located to take advantage of economies of design, infrastructure, construction and operation. In the west, coal-fired plants have generally been sited near the mine-mouth, though some plants are supplied with coal by rail at intermediate locations between mine-mouth and load centers.

Most North American coal steam-electric plants operate at sub-critical steam conditions. Supercritical steam cycles operate at higher temperature and pressure conditions at which the liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency with corresponding reductions in fuel cost, carbon dioxide production, air emissions and water consumption. Supercritical units are widely used in Europe and Japan. Some were installed in North America in the 1960s and 70s but the technology was not widely adopted because of low coal costs and the poor reliability of some early units. Recent European and Japanese experience has been satisfactory[2] and many believe that supercritical technology will penetrate the North American market over the next couple of decades. We assume that future pulverized coal steam electric power plants will move toward the greater use of supercritical steam cycles. For purposes of forecasting the cost and performance of advanced technology, we assume full penetration of supercritical technology within 20 years at a cost penalty of 2 percent and a heat rate improvement of 5 percent[3] (World Bank, 1998).

## Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Coal-fired power plants are a capital-intensive generating technology. A relatively large capital investment is made for the purpose of using relatively low-cost fuel. Though they can be engineered to provide load following, capital-intensive technologies are normally used for baseload operation.

The capital cost of new coal-fired steam-electric plants has declined about 25 percent in constant dollars since the early 1990s. This is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction,

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[2] World Bank. Supercritical Coal-fired Power Plants. *Energy Issues* No 19. April 1999
[3] World Bank. Technologies for Reducing Emissions in Coal-fired Power Plants. Energy Issues No 14. August 1998.

shortened construction schedule, and increased market competition[4]. Meanwhile, coal prices have also declined in response to stagnant demand and productivity improvements in mining and transportation[5]. By way of comparison, in the Council's 1991 power plan, the overnight capital cost of a new coal-fired steam-electric plant was estimated to be $1,775 per kilowatt and the cost of Montana coal $0.68 per million Btu (escalated to year 2000 dollars). The comparable capital and fuel costs of this plan are $1,230 per kilowatt and $0.52 per million Btu, respectively.

## Development Issues

Though the economics have improved, important issues associated with development of coal-fired power plants remain. Transmission, mercury emissions and carbon dioxide production appear to be the most significant.

Transmission issues will affect the siting and development of future coal-fired power plants in the Northwest. Coal supplies, though abundant, tend to lie at considerable distance from Northwest load centers. Environmental concerns will likely preclude siting of new coal plants close to load centers. However, new plants could be sited at intermediate locations having good rail and transmission access. Delivered coal cost will be greater that the mine mouth cost of coal because of the need to haul the coal by rail. Also, fuel cost component of the rail haul costs is sensitive to fuel oil price volatility and uncertainty. Alternatively, new plants could be sited at or near the mine mouth. Coal will be less expensive and free of fuel oil price uncertainties. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana coalfields would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from coal plants sited in the Mid-Columbia area using rail haul coal. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

Coal combustion releases elemental mercury, some of which passes into the atmosphere and accumulates in the food chain where it poses a health hazard. On average, about 36 percent of the mercury contained in the coal is retained in ash or removed by existing controls.[6] Additional control of power plant mercury emissions is not currently required, however the EPA is under court order to issue rules governing control of mercury by March 2005. A promising approach to controlling mercury emissions from coal steam-electric plants is to augment mercury capture in existing particulate filters using activated carbon injection. Short-term tests of activated carbon injection on power plants using sub-bituminous coal increased capture rates to 65 percent of potential emissions. The estimated

[4] U.S. Department of Energy. *Market-based Advanced Coal Power Systems*. March 1999.
[5] The recent runup in coal prices is attributed to short-term supply-demand imbalances.
[6] U.S. Environmental protection Agency. Control of Mercury Emissions from Coal-fired Electric Utility Boilers. January 2004.

costs of the representative pulverized coal-fired power plant described below include an allowance for activated charcoal injection for mercury control.

Among the fossil fuels, coal has the highest proportion of carbon to hydrogen. This places coal-fired generation at greater risk than other resources regarding possible future limits on the production of carbon dioxide. The most promising approach to dealing with the carbon dioxide production of coal combustion is through improved generating plant efficiency and carbon dioxide separation and sequestration. Introduction of supercritical steam cycles will improve the thermal efficiency of pulverized coal-fired power plants and reduce the per-kilowatt production of carbon dioxide. However, generating technologies based on coal gasification appears to be a more effective approach for achieving both higher efficiencies and economical carbon dioxide separation capability.

## Northwest potential

New pulverized coal-fired power plants could be constructed in the Northwest for the principal purpose of providing base load power. Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. While environmental concerns would likely make siting west of the Cascades near the Puget Sound and Portland load centers difficult, existing and potential plant sites elsewhere are sufficient to meet anticipated needs for the period of the plan. New plants could be constructed at or near mine-mouth in eastern Montana, in the inter-montane region of eastern Washington, Oregon and southern Idaho and in areas adjacent to the region including northern Nevada, Alberta and British Columbia.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

## Reference plant

The reference plant is a 400-megawatt sub-critical pulverized coal-fired unit, co-located with similar units. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas de-sulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. The capital costs include a shared local switchyard and transmission interconnection, but do not include dedicated long-distance transmission facilities.

The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and might be more suitable for arid areas of the West. But dry cooling reduces the thermal efficiency of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air emissions and carbon dioxide production. The effect is about three times greater for steam-electric plants than for gas turbine combined-cycle power plants, where recent proposals have trended toward dry condenser cooling. For this reason, we assume that the majority of new coal-fired power plants would be located in areas where water availability is not critical and would use evaporative cooling.

The assumptions of this plan regarding new coal-fired steam-electric plants are described in Table I-3. Specific proposals for new coal-fired power plants might differ substantially from this case. Important variables include the steam cycle (sub-critical vs. supercritical), method of condenser cooling, transmission interconnection, the level of equipment redundancy and reliability, number of units constructed at the same site and how scheduled, level of air emission control, the type of coal used and method of delivery.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[7] levelized electricity production costs for the reference coal-fired power plant, power delivered as shown, are as follows:

| | |
|---|---|
| Eastern Montana, local service | $32/MWh |
| Eastern Montana, via existing transmission to Mid-Columbia area | $38/MWh |
| Eastern Montana, via new transmission to Mid-Columbia area | $62/MWh |
| Mid-Columbia, rail haul coal from eastern Montana | $38/MWh |

[7] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; medium case fuel price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

**Table I-3:** Resource characterization: Coal-fired steam-electric plant (Year 2000 dollars)

| **Description and technical performance** | | |
|---|---|---|
| Facility | 400 MW (nominal) pulverized coal-fired subcritical steam-electric plant, 2400 psig/1000°F/1000°F reheat. "Reduced redundancy" low-cost design. Evaporative cooling. Low-NOx burners; flue gas desulfurization; fabric particulate filter and activated charcoal filters. Co-sited with one or more additional units. | Reference plant from U.S. Department of Energy, *Market-based Advanced Coal Power Systems*, March 1999 (USDOE, 1999), modified to suit western coal and site conditions and anticipated mercury control requirements. |
| Status | Commercially mature | |
| Application | Baseload power generation | |
| Fuel | Western low-sulfur subbituminous coal. Rail-haul or mine-mouth delivery. | |
| Service life | 30 years | |
| Power (net) | 400 MW. | |
| Operating limits | Minimum load: 50 %.<br>Cold startup: 12 hours<br>Ramp rate: 0.5%/min | Values consistent with reduced-redundancy, low-cost design. Improved performance is available at additional cost. |
| Availability | Scheduled outage: 35 days/yr<br>Equivalent forced outage rate: 7%<br>Mean time to repair: 40 hours<br>Equivalent annual availability: 84% | Scheduled outage is average of 1995 - 99 NERC *Generating Availability Data System* (GADS) scheduled outage factor for 200 - 399 MW coal-fired units, rounded to nearest day.<br><br>Forced outage rate is average of GADS equivalent forced outage factor for 200 - 399 MW coal-fired units. Forced outage rate is intended as a lifecycle average. Generally higher for startup year, lower by second year, then slowly increasing over remainder plant life. |
| Heat rate (HHV, net, ISO conditions) | 9550 Btu/kWh (annual average, 2002 base technology). | Midpoint from Kitto, J. B. *Developments in Pulverized Coal-fired Boiler Technology*. Babcock & Wilcox, April 1996, increased 0.8% for SCR. |
| Vintage heat rate improvement | 0.26 %/yr (2002-25) | Assumes full penetration of supercritical steam cycle by 2021 with 5% reduction in heat rate. World Bank. *Technologies for Reducing Emissions in Coal-fired Power Plants* (World Bank 1998). Energy Issues No 14. August 1998. |
| Seasonal power output (ambient air temperature sensitivity) | Not significant | |
| Elevation adjustment for power output | Not significant | |

| Costs | | |
|---|---|---|
| Capital cost (Overnight, development and construction) | $1243/kW | Assumes two units at a site completed within two years of one another. Single unit costs assumed to be 10% greater. Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction. |
| Development & construction cash flow (%/yr) | Cash flow for "straight-through" 78-month development & construction schedule: 0.5%/0.5%/2%/10%/37%/37%/13%. | See Table I-4 for phased development assumptions used in portfolio risk studies. |
| Fixed operating costs | $40/kW/yr | From DOE (1999), excluding property taxes and insurance plus $15/yr capital replacement. |
| Variable operating costs | $1.75/MWh | Includes consumables & SCR catalyst replacement, makeup water, wastewater and ash disposal costs. From DOE (1999) plus $0.25 allowance for SCR catalyst replacement and $0.75/MWh for additional reagent and disposal costs for Hg control. |
| Incentives/Byproduct credits/CO2 penalties | Separately included in the Council's models. | |
| Interconnection and regional transmission costs | $15.00/kW/yr | Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff. |
| Transmission loss to market hub | 1.9% | Bonneville contractual line losses. |
| Technology vintage cost change (constant dollar escalation) | 0.1 %/yr (2002-25) | Assumes full penetration of supercritical steam cycle by 2021 with 2 % increase in capital and fixed operating costs. World Bank (1998). |

| Air emissions | | |
|---|---|---|
| Particulates (PM-10) | 0.072T/GWh | Roundup Power Project, MT, as permitted |
| SO2 | 0.575 T/GWh | Ibid |
| NOx | 0.336 T/GWh | Ibid |
| CO | 0.719 T/GWh | Ibid |
| VOC | 0.014 T/GWh | Ibid |
| $CO_2$ | 1012 T/GWh | Based on average carbon content of U.S. subbituminous coals (212 lb/MMBtu) and lifecycle average heat rate. |

| Development | | |
|---|---|---|
| Assumed mix of developers | For electricity price forecasting:<br>Consumer-owned utility: 25%<br>Investor-owned utility: 25%<br>Independent power producer: 50%<br>For resource comparisons & portfolio analysis:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Price forecasting (expected) mix is a GRAC recommendation.<br>Resource comparison mix is a standard mix for comparison of resources.<br>See Appendix B for project financing assumptions. |
| Development & construction schedule | Development - 36 Months<br>Construction - 42 months | "Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies. |
| Earliest commercial service | Permitted sites (MT only) - 2008<br>New sites - 2011 | |
| Site availability and development limits through 2025. | MT in-state - no limit<br>MT to Mid-Columbia - 400 MW w/o transmission expansion<br>No development in western OR or WA | Primary coal resource sufficient to meet |

**Table I-4:** Preliminary modeling characteristics - new 500kV transmission circuit from Colstrip area to Mid-Columbia (year 2000 dollars)

| | | |
|---|---|---|
| Capacity | 1000 MW | Delivered |
| Losses | 6.6% | |
| Capital cost (Overnight, development and construction) | $1590/kW | Based on delivered capacity |
| Operating costs | $8.00/kW/yr | Based on delivered capacity |
| Development & construction schedule | Development - 48 months<br>Construction - 36 months | |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-5. The cumulative schedule of the three project phases shown in Table I-5 is longer than the "straight-through" development and construction schedule shown in Table I-3.

**Table I-5:** Coal-fired steam-electric plant project phased development assumptions for risk analysis (year 2000 dollars)[8]

| | Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Feasibility study through completion of permitting | Notice to proceed to major equipment foundations complete | Start of boiler steel erection to commercial operation |
| Time to complete (single unit, nearest quarter) | 36 months | 18 months | 27 months |
| Cash expended (% of overnight capital) | 3% | 27% | 70% |
| Cost to suspend at end of phase ($/kW) | Negligible | $234 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $10 | -- |
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | $26 | -- |
| Cost of immediate termination ($/kW) | Negligible | $158 | -- |

## COAL-FIRED GASIFICATION COMBINED-CYCLE PLANTS

The production of synthetic gas fuel from coal and other solid or liquid fuels offers the opportunity for improving the environmental and economic aspects of generating electricity from coal, an abundant and low-cost energy resource. Coal gasification permits the use of efficient gas turbine combined cycle power generation, allows excellent control of air pollutants and facilitates the separation of carbon dioxide for sequestration (See Appendix K for discussion of carbon dioxide sequestration). Gasification plants can be equipped for co-production of liquid fuels, petrochemicals chemicals or hydrogen, creating the opportunity for more flexible and economical plant utilization. Gasification technology can also be used to produce synthetic fuels from petroleum coke, bitumen and biomass, providing a means of using the energy of these otherwise difficult fuels. Coal gasification power plants are in the demonstration stage of development. Issues needing resolution before widespread deployment include capital cost reduction, provision of overall plant performance warranties and demonstration of consistent plant reliability.

Coal gasification is an old technology, having been introduced in the early nineteenth century to produce “town gas” for heating and illumination. Development of the North American natural gas transportation network in the mid-20th century brought cleaner and less-expensive natural gas to urban markets and the old town gas plants, numbering over 1,000 at one time, were retired. Currently, gasification is widely employed in the

[8] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

petrochemical industry for processing of coal and petroleum residues into higher value products. Other than several demonstration projects[9], coal gasification has not penetrated the North American power generation industry. This is attributable to the availability of low-cost natural gas until recently, efficient, reliable and low-cost gas-fired combined-cycle gas turbine power plants and the high initial cost and reliability issues with gasification power plants. Rising natural gas prices, the prospect of more stringent control of particulates and mercury, and increasing acknowledgement that the production of carbon dioxide must be reduced is increasing interest in coal-fired gasification power plants.

## Technology

The leading plant configuration for electric power generation using gasified coal is the integrated gasifier combined-cycle (IGCC) power plant. Integration refers to the extraction of pressurized air from the gas turbine compressor for use as feedstock to the air separation plant, and use of the energy released in the gasification process for power generation to improve net plant efficiency. These plants use the combined-cycle gas turbine power generating technology widely used for natural gas electricity generation. A variety of gasification technologies have been developed for use with different feedstocks and for producing different products. Pressurized oxygen-blown designs are favored for power generation. Pressurization and the use of oxygen for the gasification reaction reduce the volume of the resulting raw synthetic gas. This reduces the cost of gas cleanup, eliminates the need for syngas compression and reduces the cost of $CO_2$ separation if that is desired.

The principal components of an integrated gasifier combined-cycle generating plant are as follows:

- *Coal preparation*: The coal preparation section includes the on-site fuel inventory and equipment to prepare the coal for introduction to the gasifier. The coal is crushed or ground to size and (depending upon the gasification process) either suspended in slurry or dried for feeding to the gasifier.

- *Air separation*: The air separation plant produces oxygen for the gasification reaction. Use of oxygen, rather than air as the gasification oxidant increases the energy content and reduces the volume of the synthesis gas. This reduces the cost of gas cleanup and also reduces formation of nitrogen oxides in the gas turbine. Air separation plants currently use energy-intensive cryogenic processes in which incoming air is chilled to a liquid and distilled to separate the nitrogen, oxygen and other constituents. For example, about 20 percent of the power output of the Tampa Electric IGCC demonstration plant is consumed by air separation. Large-scale membrane separation technology under development is expected to require less energy, yield improvement in net plant efficiency.

[9] Currently operating coal gasification power plants in the U.S. are the Tampa Electric Integrated Gasification Combined-cycle Project (Polk Power Station) using theChevron-Texaco gasification process, and the Wabash River Coal Gasification Repowering Project, using the ConocoPhilips E-Gas process. Additional information regarding these projects can be obtained from the U.S. Department of Energy coal and natural gas power systems website (www.fe.doe.gov/programs/powersystems/index.html.)

- *Gasification*: Processed coal and oxygen are fed to the gasifier, a large pressure vessel. The coal is partially combusted, yielding heat and raw synthetic gas consisting largely of hydrogen, carbon monoxide and carbon dioxide. Coarse particulate material is removed and recycled to the gasifier. Non-combustible coal constituents form slag and are drained, solidified, then crushed for disposal or for marketable aggregate. The leading gasification processes suitable for power generation are the Chevron-Texaco, E-Gas and Shell processes. The Texaco process is used in the Tampa Electric Polk gasification power plant and the E-Gas process is used in the Wabash River coal gasification plant. The Shell process is used at the DEMKOLEC plant at Buggenum, The Netherlands. These plants have operated successfully for several years.

- *Gas processing:* The raw synthetic gas is scrubbed, cooled, and filtered to remove particulate material to prevent damage to downstream equipment and to control air emissions. Sulfur compounds are removed using regenerative sorbants then converted to marketable elemental sulfur. If $CO_2$ is to be separated or hydrogen-based co-products to be produced, the synthetic gas is passed through a series of water gas shift reactors. Here, the CO fraction reacts with water to form $CO_2$ and hydrogen. Though about 40 to 50 percent of the mercury in the feedstock coal remains in the slag, additional mercury capture can be achieved at this point by passing the synthetic gas through activated carbon beds.

- *$CO_2$ separation:* The relatively low volume of pressurized synthetic gas fuel provides a more economic means of separating carbon dioxide compared to removing the carbon dioxide from the larger volume of post-combustion flue gasses in a conventional steam-electric plant. Separation of up to 90 percent of the carbon dioxide content of the synthesis gas appears to be feasible using available technologies. Carbon dioxide can be separated from the synthesis gas using the same selective regenerative sorbent process used to remove sulfur compounds. The carbon dioxide could than be compressed to its high-density supercritical phase for transport to sequestration sites. An existing non-generating gasification plant, Dakota Gasification, uses a sorbent process to capture a portion of its carbon dioxide production. The carbon dioxide is piped 205 miles to Weyburn, Saskatchewan where it is injected for enhanced oil recovery. Though commercial, sorbent $CO_2$ removal is energy-intensive. Research is underway, mostly at the theoretical or laboratory stage, development of selective separation membrane technology capable of withstanding the operating conditions of a gasification power plant.

- *Power generation*: The finished synthetic gas is fired in a gas turbine of the same basic design as those used for natural gas combined-cycle power plants. Nitrogen from the air separation plant can be injected to augment the mass flow. The turbine exhaust gas is passed through a heat recovery steam generator to produce steam. This steam, plus steam produced by the synthetic gas coolers is used to drive a steam turbine generator. Reliable operation of F-class gas turbines on coal-based medium-Btu synthesis gas has been demonstrated and a plant constructed today would likely use this technology. More efficient H-class machines, currently being demonstrated on natural gas fuel would likely be used in future gasification power plants.

A pure, or nearly so hydrogen feedstock results from subjecting the synthesis gas to a water gas shift reaction followed $CO_2$ separation. F-class gas turbines have operated successfully on fuel hydrogen concentrations as high as 38 percent. Similar turbines have operated at hydrogen concentrations of 60 percent. Limited short-term testing has confirmed that F-class machines can operate on 100 percent hydrogen fuel. However, long-term reliable operation of gas turbines on pure hydrogen will require resolution of significant technical issues including hydrogen embrittlement, flashback, hot section material degradation and NOx control.

Fuel cells use pure hydrogen as fuel, so are natural candidates for use in a coal gasification facility with $CO_2$ separation. One concept consists of a combined-cycle plant using high temperature fuel cells with heat recovery and a steam turbine bottoming cycle. Cost and lifetime are key obstacles to employing fuel cells in this application. Current fuel cell costs of $2,000 - 4,000 per kilowatt must be significantly reduced for economical application to a gasification plant.

## Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. The capital cost of a coal gasification combined-cycle power plant (without $CO_2$ separation) is estimated to be about 15 to 20 percent higher than the cost of conventional pulverized coal-fired units. However, because coal gasification power plants are a new technology, it is likely that cost will decline as the technology is deployed, whereas it is expected that the costs of conventional technology may increase, particularly as additional emission control requirements are enacted.

Even more so than conventional coal plants, a relatively large capital investment in a gasification plant is made for the purpose of using a low-cost fuel. Because high reliability is essential to amortizing the capital investment, multiple air separation, gasification and synthetic gas processing trains would likely be provided to ensure high plant availability. Though a basic coal gasification power plant would normally be used for baseload power production, synthetic liquid fuel or chemical manufacturing capability could be provided for additional operating flexibility. Depending upon the economics of power production, the synthetic gas output could be shifted between the combined-cycle power plant and synthetic liquid fuel or chemical production.

## Development Issues

Two gasification combined-cycle power plants are currently operating in North America and additional plants could be ordered and built today. However, high and uncertain capital costs, the extended (though ultimately successful) shakedown periods required for the existing demonstration projects and lack of overall plant performance warranties precluding commercial financing have kept coal gasification power plants from full commercialization.

Had natural gas combined-cycle plants not been the bulk power generating technology of choice for the past 15 years, these concerns undoubtedly would have been resolved. However, high natural gas prices, diminishing North American natural gas supplies and increasing acceptance of the need to curtail carbon dioxide production have prompted renewed interest in coal gasification power plants. Recent developments accelerating commercialization of gasification power plants include the May 2004 announcement by Conoco-Philips and Fluor Corporation of an alliance to develop, design, construct and operate projects utilizing Conoco-Philips E-Gas coal gasification technology; the June 2004 announcement by General Electric that it would acquire the Chevron-Texaco gasification technology business, the August 2004 announcement by American Electric Power that it plans to construct 1,000 megawatts of coal gasification power generation capacity by 2010, the October 2004 announcement of a partnership between General Electric and Bechtel to offer a standard coal gasification combined-cycle power plant, the October 2004 announcement by Cinergy that it had signed an agreement with GE/Bechtal to construct a 600 megawatt coal gasification power plant in Indiana, and the October 2004 announcement that Excelsior Energy had been selected for a US DOE grant to assist in the financing of 532 MW coal gasification power plant to be located in Minnesota.

Probable siting difficulties would likely preclude siting of new coal-fired plants near Westside Northwest load centers. New plants could be located in eastern Washington or Oregon, or Southern Idaho, with fuel supplied by rail. Rail haul costs would prompt the operators of plants located in this part of the region to use medium-Btu bituminous coal from Wyoming or Utah. Reinforcement of cross-Cascades transmission capacity might eventually be required for plants located in this area. Alternatively, plants could be located near mine-mouth in Wyoming, Eastern Montana, or Utah. New high voltage transmission circuits would be required for new mine-mouth coal plant development exceeding several hundred megawatts. As discussed in the section on conventional coal-fired power plants, only preliminary estimates of the cost of new transmission are available, however, more refined estimates are in development.

Sequestration of carbon dioxide may mandate the location of gasification power plants in the eastern portion of the region. Though ocean sequestration may eventually be proven feasible, opening opportunities for plants employing carbon dioxide separation in the western portion of the region, only certain geologic formations present in eastern Montana currently appear to be suitable for carbon dioxide sequestration (Appendix K). Thus, gasification power plants would have to be located in eastern Montana and would require new transmission interconnection to take advantage of carbon dioxide separation capability.

## Northwest Applications

Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. Coal-fired power plants constructed in the Northwest within the next several years would likely employ conventional pulverized coal technology. However, the increasing interest in coal-fired power generation and the prospect of more stringent particulate control and control requirements for mercury and $CO_2$ is accelerating the commercialization of coal gasification technology. It appears that a basic gasification power plant without $CO_2$ separation could be operating in the Northwest as early as 2011.

Locational constraints differ somewhat from those of conventional coal-fired plants. The Superior environmental performance of gasification power plants may make siting west of the Cascades near the Puget Sound and Portland load centers less challenging. However, if carbon dioxide is to be separated and sequestered, plant sites may be limited to the vicinity of deep saline aquifers and bedded salt formations of eastern Montana.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system, if not preempted by earlier generating plant development. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

## Reference Plants

The cost and performance characteristics of two IGCC plant designs are described in Table I-6. The 425 megawatt plant would not be equipped with carbon dioxide separation equipment. This type of plant could be located anywhere in the Northwest that coal and transmission are available. The extremely low air emissions could facilitate siting near load centers. The issues that have constrained commercial development of these plants are rapidly being resolved. This could lead to full commercial projects as early as 2011. This schedule is generally consistent with the proposed AEP coal gasification power plants.

The second plant is of the same general design, but includes equipment for the separation of 90 percent of the carbon dioxide produced by plant operation. It appears likely that this type of plant would have to be located in the eastern portion of the region to access geologic formations suitable for carbon dioxide sequestration. Net power output is reduced to 401 megawatt because of the additional energy required for the carbon dioxide separation and compression to pipeline transportation pressure. Though the technologies for carbon dioxide capture, transport and injection are commercially available, extended gas turbine operation on high hydrogen fuel will require further development and testing. Moreover, carbon dioxide sequestration in potentially suitable eastern Montana formations has not been demonstrated. The cost estimates of Table I-6 do not include the costs of carbon dioxide transportation or sequestration. Carbon dioxide transportation and sequestration cost estimates are provided in Appendix K to permit estimation of the total cost of power production from this plant.

Not included in the plants described in Table I-6 are liquid or hydrogen fuel co-production facilities. Inclusion of product co-production capability would increase the operational flexibility of the plant, including the ability to firm the output of wind power plants.

The benchmark[10] levelized electricity production costs for the reference coal-gasification power plant without carbon dioxide separation, power delivered as shown, are as follows:

| | |
|---|---|
| Eastern Montana, local service | \$33/MWh |
| Eastern Montana, via existing transmission to Mid-Columbia area | \$38/MWh |
| Eastern Montana, via new transmission to Mid-Columbia area | \$58/MWh |
| Mid-Columbia, rail haul coal from eastern Montana | \$38/MWh |

**Table I-6:** Resource characterization: Coal-fired gasification combined-cycle plants (Year 2000 dollars)
Source EPRI 2000 unless noted

| **Description and technical performance** | | | |
|---|---|---|---|
| Facility | Case A: 425 MW coal-fired integrated gasification combined-cycle power plant. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, solvent-based absorption sulfur stripping unit, carbon bed adsorption mercury removal and H-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3B) | Case B: 401 MW coal-fired integrated gasification combined-cycle power plant with 90% CO2 capture. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, water gas shift reactors, solvent-based selective absorption sulfur and CO2 separation, carbon bed adsorption mercury removal, CO2 compression to 2200psig and F-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3A w/2200psig CO2 product) | |
| Current Status | w/F-Class GT - Demonstration<br>w/H-class GT - Conceptual | Conceptual | |
| Application | Baseload power generation | Baseload power generation | |
| Fuel | Western low-sulfur subbituminous coal | Same as Case A | |
| Service life | 30 years | Same as Case A | |
| Power | 474 MW (gross)<br>425 MW (net) | 490 MW (gross)<br>401 MW (net) | |
| Operating limits | Minimum load: 75 %<br>Cold restart: 24 hrs<br>Ramp rate: 3 %/min | Same as Case A | Minimum is Negishi experience (JGC 2003). Lower rates may be possible with 2x1 combined-cycle configuration .<br>Cold restart is Tampa Electric experience.<br>Ramp rate is maximum w/o flare Negishi experience. |

[10] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, medium case price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

| Description and technical performance | | | |
|---|---|---|---|
| Availability | Scheduled outage: 28 days/yr<br>Equivalent forced outage rate: 10%<br>Equivalent annual availability: 83%. | Same as Case A | Design objectives for proposed WePower plant (GTW 2004).<br><br>Multiple gasifier designs could increase availability to 90% or greater. |
| Heat rate (HHV, net, ISO conditions) | 7915 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 8500 - 9000 Btu/kWh. | 9290 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 10,000 - 10,600 Btu/kWh. | |
| Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements) | -0.5 %/yr average from 2002 base through 2025 | Same as Case A | Value used for combined-cycle gas turbines. |
| Seasonal power output (ambient air temperature sensitivity) | Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1). | Same as Case A | |
| Elevation adjustment for power output | Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10). | Same as Case A | |

| Costs | | | |
|---|---|---|---|
| Capital cost (Overnight, development and construction) | $1400/kW<br>Range $1300 - $1600/kW | $1805/kW<br>Range $1650 - $1950/kW | Costs from EPRI, 2000 adjusted for additional mercury removal, project development and owner's costs. Escalated to year 2000 dollars. |
| Construction period cash flow (%/yr) | 15%/35%/35%/15% | Same as Case A | |
| Fixed operating costs | $45.00/kW/yr | $53.00/kW/yr | |
| Variable operating costs | $1.50/MWh | $1.60/MWh | Consumables from EPRI, 2000 plus mercury removal O&M from Parsons, 2002. EPRI 2000 provides turbine maintenance costs as fixed O&M though most gas turbine costs are variable. |
| CO2 transportation and sequestration | n/a | See Appendix K | |
| Byproduct credits | None assumed | None assumed | Potential sulfur and CO2 byproduct credit (CO2 for enhanced gas or oil recovery). |

| Costs | | | |
|---|---|---|---|
| Interconnection and regional transmission costs | \$15.00/kW/yr | Same as Case A | Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff. |
| Transmission loss to market hub | 1.9% | Same as Case A | Bonneville contractual line losses. |
| Technology vintage cost change (constant dollar escalation) | -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs) | Same as Case A | Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation. |

| Air Emissions & Water consumption | | | |
|---|---|---|---|
| Particulates (PM-10) | Negligible | Negligible | |
| SO2 | Negligible | Negligible | Low sulfur coal and 99.8% removal of residual sulfur |
| NOx | < 0.11T/GWh | < 0.11T/GWh | |
| CO | 0.015 T/GWh | 0.017 T/GWh | O'Keefe, 2003, scaled to heat rate |
| VOC | 0.005 T/GWh | 0.005 T/GWh | O'Keefe, 2003, scaled to heat rate |
| $CO_2$ | 791 T/GWh | 81 T/GWh (90% removal) | |
| Hg | $6.3 \times 10^{-6}$ T/GWh | $7.4 \times 10^{-6}$ T/GWh | 90% removal |
| Water Consumption | 412 T/GWh | 820 T/GWh | |

| Development | | | |
|---|---|---|---|
| Developer | For electricity price forecasting:<br>Consumer-owned utility: 25%<br>Investor-owned utility: 25%<br>Independent power producer: 50%<br>For resource comparisons & portfolio analysis:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | For electricity price forecasting:<br>Consumer-owned utility: 25%<br>Investor-owned utility: 25%<br>Independent power producer: 50%<br>For resource comparisons & portfolio analysis:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants.<br><br>Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources. |

| Development | | | |
|---|---|---|---|
| Development and construction schedule | Development - 36mo<br>Construction - 48 mo | Same as Case A. | Development schedule is consistent with O'Keefe.<br><br>Construction currently would require 54 months (O'Keefe, 2003). Expected to shorten to 38 months with experience.<br><br>"Straight-through" development. See Table I-6 for phased development assumptions used in portfolio studies. |
| Earliest commercial service | 2011 | 2011 for enhanced oil or gas recovery CO2 sequestration. 2015 - 2020 for novel CO2 repositories. | |
| PNW Site Availability | Site availability sufficient to meet regional load growth requirements through 2025. | Site availability sufficient to meet regional load growth requirements through 2025. Suitable geologic CO2 sequestration sites may be limited to eastern Montana. Montana development would require additional transmission development to serve western load centers. | |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-7. The cumulative schedule of the three project phases shown in Table I-7 is longer than the "straight-through" development and construction schedule shown in Table I-6.

**Table I-7:** Coal-fired gasification combined-cycle project phased development assumptions for the portfolio analysis (year 2000 dollars)[11]

| | Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Feasibility study through completion of permitting | Notice to proceed to major equipment foundations complete | Accept major equipment to commercial operation |
| Time to complete (single unit, nearest quarter) | 36 months | 24 months | 24 months |
| Cash expended (% of overnight capital) | 2% | 28% | 70% |
| Cost to suspend at end of phase ($/kW) | Negligible | $218 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $13 | -- |
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | $41 | -- |
| Cost of immediate termination ($/kW) | Negligible | $180 | -- |

## NATURAL GAS-FIRED SIMPLE-CYCLE GAS TURBINE POWER PLANTS

A simple-cycle gas turbine power plant (also called a combustion turbine or gas turbine generator) is an electric power generator driven by a gas turbine. Attributes of simple-cycle gas turbines include modularity, low capital cost, short development and construction period, compact size, siting flexibility and operational flexibility. The principal disadvantage is low thermal efficiency. Because of their low thermal efficiency compared to combined-cycle plants, simple-cycle gas turbines are typically used for low duty factor applications such as peak load and emergency backup service. Energy can be recovered from the turbine exhaust for steam generation, hot water production or direct use for industrial or commercial process heating. This greatly improves thermal efficiency and such plants are normally operated as base load units.

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2004, about 1,560 megawatts of simple-cycle gas turbine capacity were installed in the Northwest, comprising about 3 percent of system capacity. One thousand three hundred thirty megawatts of this capacity is pure simple-cycle and 230 megawatts is cogeneration. The power price excursions, threats of shortages and poor hydro conditions of 2000 and 2001 sparked interest in simple-cycle turbines as a hedge against high power

[11] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices, utilities exposed to hydropower uncertainty or growing peak loads.

## Technology

A simple-cycle gas turbine generator consists of a one or two-stage air compressor, fuel combustors, one or two power turbines and an electric generator, all mounted on one or two rotating shafts. The entire assembly is typically skid-mounted as a modular unit. Some designs use two gas turbines to power a single generator. Pressurized air from the air compressor is heated by burning liquid or gas fuel in the fuel combustors. The hot pressurized air is expanded through the power turbine. The power turbine drives the compressor and the electric power generator. Lube oil, starting, fuel forwarding, and control systems complete the basic package. A wide range of unit sizes is available, from less than 5 to greater than 170 megawatts.

Gas turbine designs include heavy industrial machines specifically designed for stationary applications and "aeroderivative" machines - aircraft engines adapted to stationary applications. The higher pressure (compression) ratios of aeroderivative machines result in a more efficient and compact unit than frame machines of equivalent output. Because of their lighter construction, aeroderivative machines provide superior operational flexibility including rapid black start capability, short run-up, rapid cool-down and overpower operating capability. Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out major components or the entire engine for a replacement, shortening maintenance outages. These attributes come at a price - industrial machines cost less on a per-kilowatt capacity basis and can be longer-lived. Both aeroderivative and industrial gas turbine technological development is strongly driven by military and aerospace gas turbine applications.

A simple-cycle gas turbine power plant consists of one to several gas turbine generator units. The generator sets are typically equipped with inlet air filters and exhaust silencers and are installed in acoustic enclosures. Water or steam injection, intercooling[12] or inlet air cooling can be used to increase power output. Nitrogen oxides (NOx) from fuel combustion are the principal emission of concern. Basic NOx control is accomplished by use of "low-NOx" combustors. Exhaust gas catalysts can further reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard, fuel gas compressors, a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. Fuel oil storage and supply system may be provided for alternate fuel purposes. Simple-cycle gas turbine generators are often co-located with gas-fired combined-cycle plants to take advantage of shared site infrastructure and operating and maintenance personnel.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice in the Northwest because of historically low and relatively stable prices, widespread

[12] Chilling the compressed air between air compression stages.

availability and low air emissions. Distillate fuel oil, once widely used as backup fuel, has become less common because of environmental concerns regarding air emissions and on-site fuel storage and increased maintenance and testing. It is common to ensure fuel availability by securing firm gas transportation. Propane or liquified petroleum gas (LPG) are occasionally used as backup fuel.

## Economics

The cost of power from a gas turbine plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Capital costs of a gas turbine generator plants vary greatly because of the wide range of ancillary equipment that may be required for the particular application. Features such as fuel gas compressors, selective catalytic controls for nitrogen oxides and carbon monoxide and water or steam injection add to the cost of the basic package. Transmission interconnection, gas pipeline laterals and other site infrastructure requirements can add greatly to the cost of a plant. A further factor affecting plant costs is equipment demand. During the price runups of 2000 and 2001, equipment prices ran 25 to 30 percent higher than current levels. The reported construction cost of aeroderivative units built in WECC since 2000 range from about $420 to $1,390 per kilowatt with an average of $740. The range for plants using industrial machines is $300 to $1,000 per kilowatt with an average of $580. The reference overnight capital cost of simple-cycle gas turbine power plants used for this plan is $600 per kilowatt. This is based on an aeroderivative unit. Reasons for this cost being somewhat lower than average are that it is an overnight cost, excluding interest during construction; it is in year 2000 dollars, whereas most of the WECC examples were constructed later; most of the WECC examples were built in response to the energy crisis of 2000 and 2001 during a sellers market; and finally, most of the examples are California projects with more constrained siting and design requirements that are required in the Northwest.

Fuel prices and the relatively low efficiency of simple-cycle gas turbines low are not a key issue for plants used for peaking and emergency use. Fuel cost is of greater concern for base-loaded cogeneration plants, however, the incremental fuel consumption attributable to electric power generation (“fuel charged to power”) for cogeneration units is low compared to a pure simple-cycle machine. For example, the full-load heat rates of the reference gas turbine plants of this plan are as follows: aeroderivative, no cogeneration - 9,955 Btu per kilowatt-hour; industrial, combined-cycle - 7,340 Btu per kilowatt-hour; aeroderivative, cogeneration - 5,280 Btu per kilowatt-hour. Simple-cycle gas turbines have been constructed in the Northwest for the purpose of backing up the non-firm output of hydropower plants. The cost of fuel for this application can be significant since the turbine may need to operate at a high capacity factor over many months of a poor water year.

## Development Issues

Simple-cycle gas turbines are generally easy to site and develop compared to most other power generating facilities. Sites having a natural gas supply and grid interconnection facilities are common, the projects are unobtrusive, water requirements minimal and air emissions can be controlled to low levels. Simple-cycle gas turbine generators are often sited in conjunction with natural-gas-fired combined-cycle and steam plants to take advantage of the existing infrastructure.

Air emissions can be of concern, particularly in locations near load centers where ambient nitrogen oxide and carbon monoxide levels approach or exceed criteria levels. Post-combustion controls and operational limits are used to meet air emission requirements in these areas. The commercial introduction of high temperature selective catalytic controls for NOx and CO has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants. Sulfur dioxide form fuel oil operation is controlled by use of low-sulfur fuel oil and by operational limits. Noise and vibration has been a concern at sites near residential and commercial areas and extra inlet air and exhaust silencing and noise buffering may be required at sensitive sites. Water is required for units employing water or steam injection but is not usually an issue for simple-cycle machines because of relatively low consumption. Gas-fired simple-cycle plants produce moderate levels of carbon dioxide per unit energy output.

## Northwest Potential

Applications for simple-cycle gas turbines in the Northwest include backup for non-firm hydropower in poor water years ("hydropower firming"), peak load service, emergency system support, cogeneration (discussed in Appendix J), and as an alternative source of power during period of high power prices. Though simple-cycle turbines could be used to shape the output of windpower plants, the hydropower system is expected to be a more economic alternative for the levels of windpower development anticipated in this plan. Suitable sites are abundant and the most likely applications use little fuel. If natural gas use continues to grow, additional regional gas transportation or storage capacity may be needed to supply peak period gas needed to maintain the operating capability of simple-cycle gas turbines held for reserve or peaking purposes. Local gas transportation constraints may currently exist. Electric transmission is unlikely to be constraining because of the ability to site gas turbine generators close to loads.

## Reference plant

The reference plant is based on an aeroderivative gas turbine generator such as the General Electric LM6000. The capacity of this class of machine ranges from 40 to 50 megawatts. The cost and performance characteristics of this plant are provided in Table I-8. Recently constructed simple-cycle projects in the Northwest have used both smaller machines as well as larger industrial gas turbines. Key characteristics of a plant using a typical industrial machine are also provided in Table I-8. The smaller gas turbines used for distributed generation are described in Appendix J.

Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release provisions is assumed in lieu of backup fuel. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Costs are representative of a two-unit installation co-located at an existing gas-fired power plant.

Benchmark[13] levelized electricity production costs for reference simple-cycle turbines are as follows:

| | |
|---|---|
| Aeroderivative, 10 percent capacity factor (peaking or hydro firming service) | \$152/MWh. |
| Industrial, 10 percent capacity factor (peaking or hydro firming service) | \$127/MWh |
| Aeroderivative, 80 percent capacity factor (baseload service) | \$57/MWh. |
| Industrial, 80 percent capacity factor (baseload service) | \$53/MWh |

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) of the reference aeroderivative unit under the benchmark financing assumptions is \$89 per kilowatt per year. The benchmark capacity cost of a typical plant using industrial gas turbine technology is \$50 per kilowatt per year.

**Table I-8:** Resource characterization: Natural gas fuelled simple-cycle gas turbine power plant (Year 2000 dollars)

| **Description and technical performance** | | |
|---|---|---|
| Facility | Natural gas-fired twin-unit aeroderivative simple-cycle gas turbine plant. Reference plant consists of (2) 47 MW gas turbine generators and typical ancillary equipment. Low-NOx combustors, water injection and SCR for NOx control and CO oxidizing catalyst for CO and VOC control. | Selected cost and performance assumptions for a basic plant (low-NOx burners emission control) using typical (80 - 170 MW) industrial-grade gas turbines are noted. Additional emission controls and other ancillary equipment will increase costs. Industrial turbine performance will differ for some characteristics not noted. |
| Status | Commercially mature | |
| Applications | Peaking duty, hydropower or windpower firming, emergency service | |
| Fuel | Pipeline natural gas. Firm transportation contract with capacity release provisions. | |
| Service life | 30 years | |
| Power (net) | New & clean: 47 MW/unit<br>Lifecycle average: 46 MW/unit | New & Clean: GE LM6000PC Sprint ISO rating less 2% inlet & exhaust losses. Lifecycle average is based on capacity degradation of 4% at hot gas path maintenance time, 75% restoration at hot gas path maintenance and 100% restoration at major overhauls. |
| Operating limits | Minimum load: 25% of single turbine baseload rating.<br>Cold startup: 8 minutes<br>Ramp rate: 12.5 %/min | Heat rate begins to increase rapidly at about 70% load. Startup time & ramp rate are for Pratt & Whitney FT8. |

[13] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

| Description and technical performance | | |
|---|---|---|
| Availability | Scheduled outage: 10 days/yr<br>Equivalent forced outage rate: 3.6%<br>Mean time to repair: 80 hours<br>Equivalent annual availability: 94% | The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every sixth year and a 28-day major overhaul every twelfth year (inspection sequence is per General Electric recommendations. Actual intervals are a function of startups and hours of operation.). The assumed rate also includes two additional 28-day scheduled outages during the 30-year plant life.<br><br>Based on the LM6000 fleet engine reliability of 98.8% (Fig 2 General Electric Power Systems. *GE Aeroderivative Gas Turbines - Design and Operating Features*, GER 3695e) and the assumption that engine-related outages represent about a third of all forced outages for a simple-cycle plant.<br><br>Mean time to repair is NERC Generating Availability Data System (GADS) average for full outages. |
| Heat rate (HHV, net, ISO conditions) | New & clean: 9900 Btu/kWh<br>Lifetime average: 9960 Btu/kWh<br>Industrial machine: 10,500 Btu/kWh (lifetime average). | New & Clean is GRAC recommendation based on operator experience and typical vendor warranties.<br>Lifecycle average based on capacity degradation of 1% during the hot gas path maintenance interval; 50% restoration at hot gas path maintenance and 100% restoration at major overhauls. |
| Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements) | -0.5 %/yr average from 2002 base through 2025 | Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation. |
| Seasonal power output (ambient air temperature sensitivity) | Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1). | |
| Elevation adjustment for power output | Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10). | |

| Costs | | |
|---|---|---|
| Capital cost | $600/kW (overnight cost)<br>Industrial machine: $375/kW. | Includes development and construction. Overnight cost excludes financing fees and interest during construction. Based on new and clean rating. Derived from reported plant costs (2002-03), adjusted to approximate equilibrium market conditions. Single unit cost about 10% greater. |
| Construction period cash flow (%/yr) | 100% (one year construction) | See Table I-8 for phased development assumptions used in portfolio risk studies. |
| Fixed operating costs | $8.00/kW/yr.<br>Industrial machine: $6.00/kW/yr. | Includes labor, fixed service costs, management fees and general and administrative costs and allowance for equipment replacement costs (some normally capitalized). Excludes property taxes and insurance (separately calculated in the Council's models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a single unit plant estimated to be 167% of example plant costs. Based on new and clean rating. |
| Variable operating costs | $8/MWh<br>Industrial machine: $4.00/MWh | Routine O&M, consumables, utilities and miscellaneous variable costs plus major maintenance expressed as a variable cost. Excludes greenhouse gas offset fee (separately calculated in the Council's models). |
| Incentives/Byproduct credits/CO2 penalties | Separately included in the Council's models. | |
| Interconnection and regional transmission costs | Simple-cycle units are assumed to be located within a utility's service territory. | |
| Regional transmission losses | Simple-cycle units are assumed to be located within a utility's service territory. | |
| Technology vintage cost change (constant dollar escalation) | -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs) | Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation. |

| Typical air emissions (Plant site, excluding gas production & delivery) | | |
|---|---|---|
| Particulates (PM-10) | 0.09 T/GWh | Typical emissions at normal operation over range of loads (50 to 100%). From West Cascades Energy Facility Prevention of Significant Deterioration Application November 2003. http://www.lrapa.org/permitting/applications_submitted/ |
| SO2 | 0.09 T/GWh | Ibid |
| NOx | 0.009 - 0.01 T/GWh | Ibid |
| CO | 0.09 - 0.11 T/GWh | Ibid |
| Hydrocarbons/VOC | 0.08 T/GWh | Ibid |
| $CO_2$ | 582T/GWh | Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rate. |

| Development | | |
|---|---|---|
| Assumed mix of developers | Expected mix:<br>Consumer-owned utility: 40%<br>Investor-owned utility: 40%<br>Independent power producer: 20%<br>Benchmark mix:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants.<br><br>Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources. |
| Development & construction schedule | Development - 18 months<br>Construction - 12 months | "Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies. |
| Earliest commercial service | New sites - 2006 | |
| Site availability and development limits through 2025 | Adequate to meet forecast Northwest needs. | |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-9. The cumulative schedule of the three project phases shown in Table I-9 is longer than the "straight-through" development and construction schedule shown in Table I-8.

**Table I-9:** Natural gas-fired simple-cycle project phased development assumptions for risk analysis (year 2000 dollars)[14]

| | Project Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Feasibility study through completion of permitting | Notice to proceed to major equipment foundations complete | Accept major equipment to commercial operation |
| Time to complete (single unit, nearest quarter) | 18 months | 12 months | 3 months |
| Cash expended (% of overnight capital) | 2% | 94% | 5% |
| Cost to suspend at end of phase ($/kW) | Negligible | $25 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $17 | -- |
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | -$158 | -- |
| Cost of immediate termination ($/kW) | Negligible | -$125 | -- |

## NATURAL GAS FUELED COMBINED-CYCLE GAS TURBINE POWER PLANTS

For over a decade, high thermal efficiency, low initial cost, high reliability, low air emissions, and until recently, low natural gas prices have led to the choice of combined-cycle gas turbines for new bulk power generation. Other attractive features include operational flexibility, inexpensive optional power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants have become an important element of the Northwest power system, comprising 68 percent of generating capacity additions from 2000 through 2004. Natural gas-fired combined-cycle capacity has increased to 14 percent of regional generating capacity.

## Technology

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat of the turbine exhaust gas yields high thermal efficiency compared to other combustion technologies. Combined-

[14] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[15]). Cogeneration provides additional efficiency. In these, steam is bled from the steam generator, steam turbine or turbine exhaust to serve thermal loads[16].

A single-train combined-cycle plant consists of one gas turbine, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" or "single train" configuration), often all mounted on a single shaft. F-class gas turbines - the most common technology in use for large plants - in this configuration can produce about 270 megawatts. Uncommon in the Northwest, but common in high load growth are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in construction and operational economies and slightly improved efficiency. A 2 x 1 configuration using F-class technology will produce about 540 megawatts of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator to produce additional steam). 20 to 50 megawatts can be gained from a single-train F-class plant with duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental capital cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, extensive delivery network and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide and increased testing and maintenance. It is common to ensure fuel availability by subscribing to firm gas transportation.

Combined-cycle plant development benefits from improved gas turbine technology, in turn driven by military and aerospace applications. The tradeoff to improving gas turbine efficiency is to increase power turbine inlet temperatures while maintaining reliability and maintaining or reducing NOx formation. Most recently completed combined-cycle plants use "F-class" gas turbine technology. F-class machines are distinguished by firing temperatures of 1,300$^{o}$C (2370$^{o}$ F) and basic [17]HHV heat rates of 6,640 - 6,680 Btu per kilowatt-hour in combined-cycle configuration. More advanced "G-class" machines, now in early commercial service, operate at firing temperatures of about 1,400$^{o}$ C (2550$^{o}$ F) and basic HHV heat rates of 6,490 - 6,510 Btu per kilowatt-hour in combined-cycle configuration. H-class machines, entering commercial demonstration, feature steam cooling

[15] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.

[16] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.

[17] Higher heat value, new and clean, excluding air intake, exhaust and auxiliary equipment losses.

of hot section parts, firing temperatures in the 1,430$^{o}$ C range (2,610$^{o}$ F), and an expected HHV heat rate of 6,320 Btu per kilowatt-hour.

## Economics

The cost of power from a combined-cycle plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Typically the largest component of these costs will be variable fuel cost. Combined-cycle gas turbines deliver high efficiency at low capital cost. The overnight capital cost of the reference combined-cycle plant, $525 per kilowatt, is the lowest of any of the generating technologies in this plan except for industrial simple-cycle gas turbines. As long as natural gas prices remained low, the result was a power plant capable of economical baseload operation at low capital investment - an unbeatable combination leading to the predominance of combined-cycle plant for capacity additions on the western grid over the past decade. Higher gas prices combined with depressed power prices have eroded this competitive advantage and many combined-cycle plants are currently operating at low capacity factors. The future economic position of combined-cycle plants is uncertain. If natural gas prices decline from current highs, these plans may again become economically competitive baseload generating plants. Their economic position could be further improved by more aggressive efforts to reduce carbon dioxide production. The low carbon-to-hydrogen ratio of natural gas and the high thermal efficiency of combined-cycle units could position the technology to displace conventional coal-fired plants if universal carbon dioxide caps or penalties were established.

## Development Issues

Though natural gas production activities can incur significant environmental impacts, the environmental effects of combined cycle power plants are relatively minor. The principal environmental concerns associated with the operation of combined-cycle gas turbine plants are emissions of nitrogen oxides and carbon monoxide. Fuel oil operation may produce in addition, sulfur dioxide. Nitrogen oxide abatement is accomplished by use of “dry low-NOx” combustors and selective catalytic reduction within the heat recovery steam generator. Limited quantities of ammonia are released by operation of the nitrogen oxide selective catalytic reduction system. Carbon monoxide emissions are typically controlled by use of an oxidation catalyst within the heat recovery steam generator. If operating on natural gas, no special controls are used for particulates or sulfur oxides as these are produced only in trace amounts. Low sulfur fuel oil and limitation on hours of operation are used to control sulfur oxides when using fuel oil.

Though proportionally about two thirds less than for steam-electric technologies, the cooling water consumption of combined-cycle plants is significant if evaporative cooling is used. Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the arid west. Water consumption can be reduced by use of dry (closed-cycle) cooling, though at added cost and reduced efficiency. Over time it appears likely that an increasing number of new projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of fossil fuels. However, because of the relatively low carbon content of natural gas and the high efficiency of combined-cycle technology, the carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 pounds $CO_2$ per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 pounds $CO_2$ per kilowatt-hour.

## Northwest Potential

New combined-cycle power plants would be constructed in the Northwest for the purpose of providing base and intermediate load service. While the economics of combined-cycle plants are currently less favorable than in the recent past, a decline in natural gas prices or more aggressive carbon dioxide control efforts could lead to additional development of combined-cycle plants. Suitable sites are abundant, including many close to Westside load centers. Proximity to natural gas mainlines and access to loads via existing high voltage transmission are the key site requirements. Secondary factors include water availability, ambient air quality and elevation. Permits are currently in place for several thousand megawatts of new combined-cycle capacity and are being sought for several thousand more.

More constraining may be future natural gas supplies. While there is currently no physical shortage of domestic natural gas, consensus is emerging that ability to tap the abundant off-shore sources of natural gas via LNG import capability will be necessary to control long-term natural gas prices.

## Reference plant

The reference plant is based on an F-class gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 megawatts of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using an incrementally-priced firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft. Specific characteristics of the reference plant are shown in Table I-10. Key cost and performance characteristics for a single-train (1x1) plant are also noted.

Benchmark[18] levelized electricity production costs for reference combined-cycle turbines are as follows:

| | |
|---|---|
| 540/610 MW combined-cycle, baseload increment, 80 percent capacity factor | $41/MWh |
| 540/610 MW combined-cycle, peaking increment, 10 percent capacity factor | $117/MWh |
| 270/305 MW combined-cycle, baseload increment, 80 percent capacity factor | $43/MWh |
| 270/305 MW combined-cycle, peaking increment, 10 percent capacity factor | $126/MWh |

[18] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) for the peaking increment of the reference 540/610 megawatt unit under the benchmark financing assumptions is $71 per kilowatt per year. The capacity cost for the peaking increment of the reference 270/305 megawatt unit under the benchmark financing assumptions is $79 per kilowatt per year.

**Table I-10:** Resource characterization: Natural gas combined-cycle plant (Year 2000 dollars)

| **Description and technical performance** | | |
|---|---|---|
| Facility | Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. F Class gas turbine technology. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration load. Dry SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling. | Key cost and performance assumptions for single train (1x1) plants are noted. |
| Status | Commercially mature | |
| Application | Baseload and peaking generation, cogeneration | |
| Fuel | Pipeline natural gas. Firm transportation contract with capacity release provisions. | |
| Service life | 30 years | |
| Power (net) | New & clean: 540 MW (baseload), 610 MW (peak)<br>Lifetime average: 528 MW (baseload), 597 MW (peak) | Lifetime average is based on 1 % degradation per year and 98.75% recovery at hot gas path inspection or major overhaul (General Electric). |
| Operating limits | Minimum load: 40% of baseload rating.<br>Cold startup: 3 hours<br>Ramp rate: 7 %/min | Minimum load for single-train plant is 80% of baseload rating. Minimum load is assumed to be one gas turbine in service at point of minimum constant firing temperature operation. |
| Availability | Scheduled outage: 18 days/yr<br>Equivalent forced outage rate: 5%<br>Mean time to repair: 24 hours<br>Equivalent annual availability: 90% (Reduce 2.2% if using new & clean capacity) | The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every third year and a 28-day major overhaul every sixth year (General Electric recommendations for baseload service). The assumed rate also includes two additional 28-day scheduled outages and one six-month plant rebuild during the 30-year plant life.<br><br>The forced outage rate is from NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants.<br><br>Mean time to repair is GADS average for full outages. |

| Description and technical performance | | |
|---|---|---|
| Heat rate (HHV, net, ISO conditions) | New & clean (Btu/kWh): 6880 (baseload); 9290 (incremental duct firing); 7180 (full power)<br>Lifetime average (Btu/kWh): 7030 (baseload); 9500 (incremental duct firing); 7340 (full power). 2002 base technology. | Baseload is new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from General Electric. Duct firing heat rate is Generating Resource Advisory Committee (GRAC) recommendation. |
| Technology vintage heat rate improvement (Surrogate for cumulative non-cost technical improvements) | -0.5 %/yr average from 2002 base through 2025 | Approximate 95% technical progress ratio (5% learning rate). Mid-range between EIA Assumptions to the Annual Energy Outlook 2004 (Table 39) (pessimistic) & Chalmers University of Technology, Feb 2001 (Sweden) (optimistic). Forecast WECC penetration is used as surrogate for global production. |
| Seasonal power output (ambient air temperature sensitivity) | Figure I-1 | Figure I-1 is based on power output ambient temperature curve for a General Electric STAG combined-cycle plant, from Figure 34 of GE Combined-cycle Product Line and performance (GER 3574H) and 30-year monthly average temperatures for the sites shown. |
| Elevation adjustment for power output | Table I-11 | Based on the altitude correction curve of Figure 9 of General Electric Power Systems GE Gas Turbine Performance characteristics (GER 3567H). |

| Costs & development schedule | | |
|---|---|---|
| Capital cost (Overnight, development and construction) | Baseload configuration: $565/kW<br>Power augmentation configuration: $525/kW<br>Incremental cost of power augmentation (duct burners) $225/kW. | Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction. 1x1 plant estimated to cost 110% of example plant. Based on new and clean rating. Derived from reported plant costs (2002), adjusted to approximate equilibrium market conditions. |
| Development & construction cash flow (%/yr) | Cash flow for “straight-through” 48-month development & construction schedule: 2%/2%/24%/72% | See Table I-11 for phased development assumptions used in portfolio risk studies. |
| Fixed operating costs | Baseload configuration: $8.85/kW/yr.<br>Power augmentation configuration: $8.10/kW/yr. | Includes operating labor, routine maintenance, general & overhead, fees, contingency, and allowances for (normally) capitalized equipment replacement costs and startup costs. Excludes property taxes and insurance (separately calculated in the Council’s models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a 1x1 plant estimated to be 167% of example plant costs. Values are based on new and clean rating. |

| Costs & development schedule | | |
|---|---|---|
| Variable operating costs | $2.80/MWh | Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes any CO2 offset fees or penalties. |
| Incentives/Byproduct credits/CO2 penalties | Separately included in the Council's models. | |
| Interconnection and regional transmission costs | $15.00/kW/yr | Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff. |
| Regional transmission losses | 1.9% | Bonneville contractual line losses. |
| Technology vintage cost change (constant dollar escalation) | -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs) | See technology vintage heat rate improvement, above. |

| Typical air emissions (Plant site, excluding gas production & delivery) | | |
|---|---|---|
| Particulates (PM-10) | 0.02 T/GWh | River Road project permit limit |
| SO2 | 0.002 T/GWh | River Road project actual |
| NOx | 0.039 T/GWh | Ibid |
| CO | 0.005 T/GWh | Ibid |
| Hydrocarbon/VOC | 0.0003 T/GWh | Ibid |
| Ammonia | 0.0000006 T/GWh | Ibid. Slip from catalyst. |
| $CO_2$ | 411 T/GWh (baseload operation)<br>429 T/GWh (full power operation) | Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rates. |

| Development | | |
|---|---|---|
| Assumed mix of developers | For electricity price forecasting:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 20%<br>Independent power producer: 60%<br>For resource comparisons & portfolio analysis:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Price forecasting (expected) mix is a GRAC recommendation.<br>Resource comparison mix is a standard mix for comparison of resources. |
| Development & construction schedule | Development - 24 Months<br>Construction - 24 months | "Straight-through" development. See Table I-11 for phased development assumptions used in portfolio risk studies. |
| Earliest commercial service | Suspended projects - 2006<br>Permitted sites - 2007 | |
| Site availability and development limits through 2025 | Adequate to meet forecast Northwest needs. | |

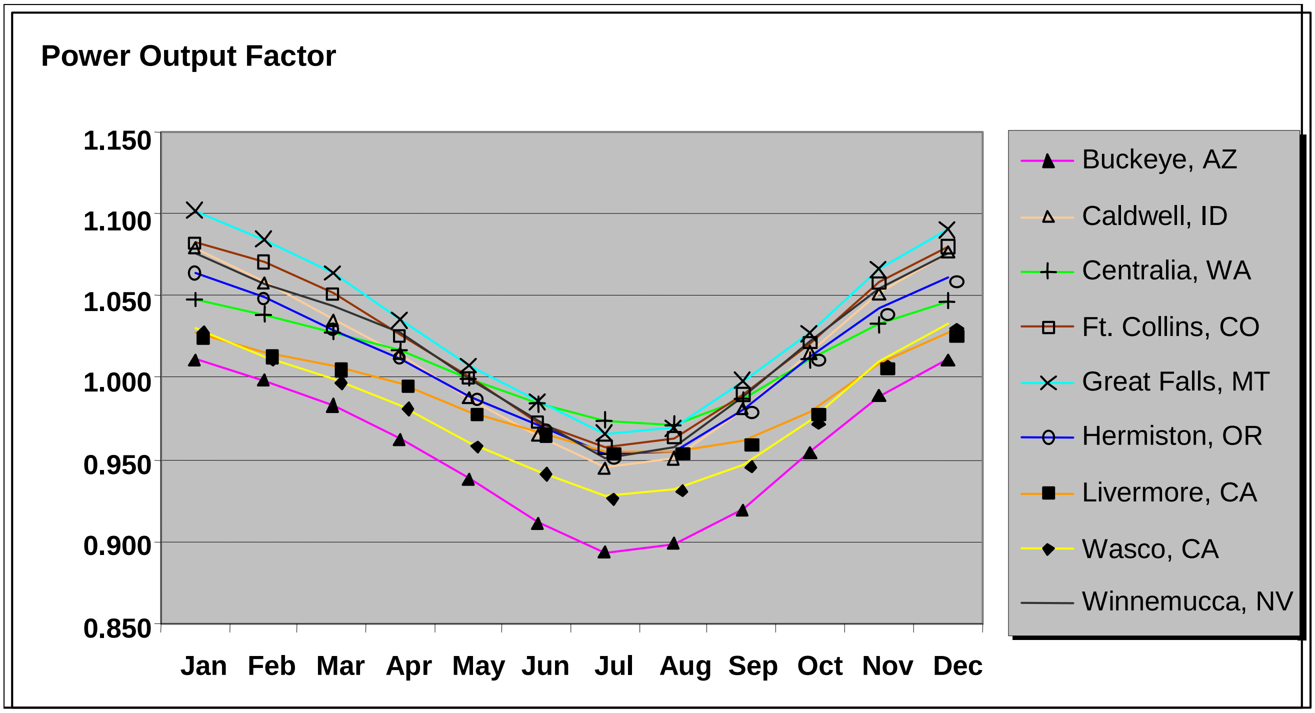


**Figure I-1:** Gas turbine combined-cycle average monthly power output temperature correction factors for selected locations (relative to ISO conditions)

**Table I-11:** Gas turbine power output elevation correction factors for selected locations

| Location | Elevation (ft) | Power Output Factor |
|---|---|---|
| Buckeye, AZ (near Palo Verde) | 890 | 0.972 |
| Caldwell, ID | 2370 | 0.923 |
| Centralia, WA | 185 | 0.995 |
| Ft. Collins, CO | 5004 | 0.836 |
| Great Falls, MT | 3663 | 0.880 |
| Hermiston, OR | 640 | 0.980 |
| Livermore, CA | 480 | 0.985 |
| Wasco, CA (nr. Kern County plants) | 345 | 0.990 |
| Winnemucca, NV | 4298 | 0.859 |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-12. The cumulative schedule of the three project phases shown in Table I-12 is longer than the "straight-through" development and construction schedule shown in Table I-10.

**Table I-12:** Natural gas combined-cycle project phased development assumptions for risk analysis (year 2000 dollars)[19]

| | Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Feasibility study through completion of permitting | Notice to proceed to major equipment foundations complete | Accept major equipment to commercial operation |
| Time to complete (single unit, nearest quarter) | 24 months | 15 months | 12 months |
| Cash expended (% of overnight capital) | 4% | 24% | 72% |
| Cost to suspend at end of phase ($/kW) | Negligible | $169 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $4 | -- |
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | $25 | -- |
| Cost of immediate termination ($/kW) | Negligible | $100 | -- |

## WINDPOWER

The first commercial-scale wind plant in the Northwest was the 25 megawatt Vansycle project in Umatilla County, Oregon, placed in service in 1998. Development of windpower proceeded rapidly following the energy crisis of 2000 and six commercial-scale projects totaling 541 megawatts of capacity are now in-service in the region. Regional utilities also own or contract for the output of Wyoming projects developed during this same period. Together, these projects currently comprise 651 megawatts of installed capacity, about 1.3 percent of the total capacity available to the region. This capacity produces about 220 average megawatts of energy. Declining power prices and expiration of federal production tax credits at the end of 2003 brought an end to this period of rapid wind power development. However, Northwest utilities continue to be interested in securing additional windpower and

[19] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

development is expected to resume following the recent extension of the production tax credit through 2005.

## Technology

Wind energy is converted to electricity by wind turbine generators - tower-mounted electric generators driven by rotating airfoils. Because of the low energy density of wind, utility-scale wind turbine generators are physically large, and a wind power plant comprised of tens to hundreds of units. In addition to the wind turbine generators, a wind power plant (often called a “wind farm”) includes meteorological towers, service roads, a control system (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid.

The typical utility-scale wind turbine generator is a horizontal axis machine of 600 to 1,500 kilowatts capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers ranging to over 250 feet in height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Machines for terrestrial applications are fully commercial and as reliable as other forms of power generation. Turbine size has increased rapidly in recent years and multi-megawatt (2 - 4.5 megawatts) machines are being introduced. These are expected to see initial service in European offshore applications.

## Economics

The cost of power from a wind plant is comprised of capital service costs, fixed and variable operating and maintenance costs, system integration costs and transmission costs. Capital costs represent the largest component of overall costs and machine costs the largest component of capital costs. Though capital costs of wind power plants have remained relatively constant near $1,000 per kilowatt for several years, production costs have declined because of improvements in turbine performance and reliability, site selection and turbine layout. Busbar (unshaped) energy production costs at better sites are now in the range of $40-50 per megawatt-hour, excluding incentives.

Shaping costs are reported to be in the range of $3 to 7 per megawatt-hour, much lower than earlier estimates. While this range may be representative of the cost of shaping the output of the next several hundred megawatts of wind power developed in the region, shaping costs for additional levels of windpower development are uncertain. In the Northwest, shaping of additional increments of windpower capacity may draw water from higher value uses, increasing shaping cost. Offsetting this is the possible effect of geographic diversity in reducing the variability of windpower output. We assume a $4.55 per megawatt-hour shaping cost for the first 2,500 megawatts of wind capacity. The cost of shaping the second 2,500 megawatts of wind capacity, and any Montana capacity is assumed to be $9.75 per megawatt-hour.

The competitive position of wind power remains heavily dependent upon the federal production tax credit and to a lesser extent the value of green tags. Project construction ceased with expiration of the production tax credit at the end of 2003. The recent one-year reinstatement of the production tax credit will likely bring the cost of windpower below wholesale power value and result in a cycle of new development. But unless natural gas prices remain high, and mandatory carbon dioxide penalties enacted, it will be several years before wind power can compete with other resource options without incentives. The most important incentive is the federal production tax credit, currently about $18 per megawatt-hour, available for the first ten years of project operation. Complementing the production tax credit have been energy premiums resulting from the market for "green" power that has developed in recent years. This market is driven by retail green power offerings, utility efforts to diversify and "green up" resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, renewable portfolio standards and system benefits funds established in conjunction with industry restructuring. Because of the great uncertainty regarding future production tax credit and green tag values, these are modeled as uncertainties in the portfolio risk analysis (Chapter 6).

## Development Issues

Many of the issues that formerly impeded the development of wind power have been largely resolved in recent years, clearing the way for the significant development that has occurred in the Northwest. Avian mortality, aesthetic and cultural impacts have been alleviated in the Northwest by the use of sites in dryland agriculture. The impact of wind machines on birds, which has been significant at some California wind plants has been also reduced by better understanding of the interrelationship of birds, habitat and wind turbines. Siting on arid habitat of low ecological productivity, elimination of perching sites on wind machines, slower turbine rotation speeds, and siting of individual turbines with a better understanding of avian behavior have greatly reduced avian mortality at recently developed projects. Bat mortality, however, is of concern at some sites.

It appears likely that several hundred to a thousand or more megawatts of wind power can be shaped at relatively low cost. The cost of firming and shaping the full amount of wind energy included in this plan are uncertain, pending further operating experience and analysis. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind developers because of the low capacity factor of wind plants. The wind potential included in this plan is expected to be accessible without significant expansion of transmission capacity.

Development of the high quality and extensive wind resources of eastern Montana is confronted by the same transmission issues faced by development of mine mouth coal-fired power plants in eastern Montana, except that the comparatively low capacity factor of a wind project renders transmission even more expensive. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern

Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from wind plants sited in resource areas of lesser quality west of the Continental Divide. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

## Northwest Potential

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

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

Intensive prospecting and monitoring are required to confirm the potential of a wind resource area. Though much wind resource information is proprietary, the results of early resource assessment efforts of the Bonneville Power Administration, the U.S. Department of Energy and the State of Montana, recently compiled resource maps based on computer modeling plus a the locations of announced wind projects give a sense of the general location and characteristics of prime Northwest wind resource areas. Educated guesses by members of the Council's Generating Resource Advisory Committee suggest that several thousand megawatts of developable potential occur within feasible interconnection distance of existing transmission. This estimate is supported by the 3,600 megawatts aggregate capacity of announced but undeveloped wind projects. For the base case portfolio analyses and power price forecasting we assume 5,000 megawatts of developable potential west of the Continental Divide.

## Reference plants

The reference plant is a 100-megawatt wind plant located in a prime wind resource area within 10 to 20 miles of an existing substation. The plant would consist of 50 to 100 utility-scale wind machines. Sites west of the Rocky Mountains are classified into two blocks of 2,500 megawatts each. The first block represents the best, undeveloped sites, with an average capacity factor of 30 percent. These sites are assumed to be the first developed and thereby secure relatively low shaping costs of $4.55 per megawatt-hour. The second block is of lesser quality, yielding a capacity factor of 28 percent[20]. Because these lesser quality sites are likely to be developed later than the first block, they are assumed to incur higher shaping costs of $9.75 per megawatt-hour. Sites east of the Rocky Mountains are assumed to yield a capacity factor of 36 percent and incur a shaping cost of $9.75 per megawatt-hour. These sites are electrically isolated from the regional load centers and would require construction of long-distance transmission to access outside markets. Planning assumptions for the three resource blocks are provided in Table I-13.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[21] levelized electricity production costs for reference wind power plants, power shaped and delivered as shown, are as follows:

| | |
|---|---|
| Eastern Montana, local service | $41/MWh |
| Eastern Montana, via existing transmission to Mid-Columbia area | $40/MWh |
| Eastern Montana, via new transmission to Mid-Columbia area, shaped @Mid-C | $82/MWh |
| Mid-Columbia, Block I | $43/MWh |
| Mid-Columbia, Block II | $50/MWh |

[20] Because of portfolio model limitations, this block was assumed to operate at a 30 percent capacity factor.
[21] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, year 2000 dollars. No production tax credit or green tag credit.

**Table I-13:** Resource characterization: Wind power plants (Year 2000 dollars)

| **Facility description and technical performance** | | |
|---|---|---|
| Facility | 100 MW central-station wind power project. | Utility-scale projects may range from 25 to 300 MW. |
| Status | Commercial | . |
| Application | Intermittent baseload power generation | |
| Fuel | n/a | |
| Service life | 30 years | Typical design life for Danish wind turbine generators is estimated to be 20 years (Danish Wind Industry Association). 30 years, with allowance for capital replacement is used for consistency with other resources. |
| Power | 100 MW | Net of in-farm and local interconnection losses. |
| Operating limits | n/a | |
| Availability | Scheduled outage: Included in capacity factor estimate.<br>Equivalent forced outage rate: Included in capacity factor estimate.<br>Mean time to repair: Zero hours | |
| Capacity factor | West of Continental Divide Block 1: 30%<br>West of Continental Divide Block 2: 28%<br>East of Continental Divide Block 3: 36% | Net of in-farm and local interconnection losses and outages and elevation (atmospheric density) effects. |
| Technology development | 2000-04 annual average: -3.1 %<br>2005-09 annual average: -2.3 %<br>2010-14 annual average: -2.1 %<br>2015-19 annual average: -1.9 % | Applied to capital and fixed O&M cost. Represents effective reduction in production cost from cost & performance improvements. Based on 90% technical progress ratio (10% learning rate), derived from historical trends. |
| Seasonal power output | Table I-14 | |
| Diurnal power output | None assumed | Insufficient evidence of diurnal pattern for Northwest resource areas. |
| Elevation adjustment for power output | Implicit in capacity factor. | |

| **Costs** | | |
|---|---|---|
| Development & construction | $1010/kW (overnight).<br>Range $1120/kW (25 MW project) to $930/kW (300 MW project). | Includes project development, turbines, site improvements, erection, substation, startup costs & working capital. "Overnight" cost excludes interest during construction. |
| Development and construction annual cash flow | 1% - 13% - 86% | "Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies. |
| Capital replacement | $2.50/kW/yr | Levelized cost of major capital replacements over life of facility (e.g. blade or gearbox replacement) (EPRI, 1997) |

| Costs | | |
|---|---|---|
| Fixed operating cost | $17.50/kW/yr. plus property tax & insurance.<br>Property tax: 1.4%/yr of capital investment<br>Insurance: 0.25%/yr of capital investment | Includes operating labor, routine maintenance, general & overhead costs |
| Variable operating cost | $1.00/MWh | Land lease |
| Interconnection and in-region firm-point-to-point transmission and required ancillary services. | $15.00/kW/yr | Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded |
| Transmission energy loss adjustment. | 1.9% | Represents transmission losses within modeled load-resource area. Losses between load-resource areas are separately modeled. (BPA contractual line losses.) Omit for busbar calculations. |
| Vintage cost escalation (technology development) | 2000-04 annual average: -3.1 %<br>2005-09 annual average: -2.3 %<br>2010-14 annual average: -2.1 %<br>2015-19 annual average: -1.9 % | Net reduction in capital and fixed O&M cost of cost & performance improvements. Based on 10% learning rate (90% progress ratio) for each doubling in global capacity. |
| Shaping cost | West of Continental Divide Block 1: $4.55/MWh<br>West of Continental Divide Block 2: $9.75MWh<br>East of Continental Divide Block 3: $9.75/MWh | Applied to simulate flat product comparable to dispatchable resources. |
| Production tax credit | Modeled as described in Chapter 6 | |
| Value of "green" attributes | Modeled as described in Chapter 6 | |

| Development | | |
|---|---|---|
| Assumed mix of developers | For electricity price forecasting:<br>Consumer-owned utility: 15%<br>Investor-owned utility: 15%<br>Independent power producer: 70%<br>For resource comparisons & portfolio analysis:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Price forecasting (expected) mix is a GRAC recommendation.<br>Resource comparison mix is a standard mix for comparison of resources. |
| Development & construction schedule | Development - 18 months<br>Construction - 12 months | "Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies. |
| Earliest commercial service | Permitted sites - 2005<br>New sites - 2008 | |
| Resource availability and development limits 2005 - 2024 | West of Cascades: 500 MW<br>ID, OR, WA east of Cascades: 4500 MW<br>MT in-state - no limit<br>MT to Mid-Columbia - 400 MW w/existing transmission | |

**Table I-14:** Normalized monthly wind energy distribution

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Basin & Range | 1.19 | 1.39 | 1.07 | 1.05 | 0.94 | 0.71 | 0.56 | 0.61 | 0.72 | 0.74 | 1.59 | 1.43 |
| Cascades & Inland | 1.03 | 0.90 | 1.07 | 1.07 | 1.21 | 1.07 | 1.11 | 1.07 | 0.94 | 0.73 | 0.85 | 0.96 |
| Northwest Coast | 1.19 | 1.57 | 1.07 | 0.86 | 0.84 | 0.84 | 1.01 | 0.54 | 0.66 | 0.80 | 1.40 | 1.21 |
| Rockies & Plains | 1.61 | 1.57 | 1.02 | 0.84 | 0.77 | 0.73 | 0.35 | 0.42 | 0.52 | 1.00 | 1.30 | 1.88 |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-15. The cumulative schedule of the three project phases shown in Table I-15 is longer than the "straight-through" development and construction schedule shown in Table I-13.

**Table I-15:** Wind project phased development assumptions for risk analysis (year 2000 dollars)[22]

| | Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Feasibility study through completion of permitting | Turbine order through ready to ship | Turbine acceptance to commercial operation |
| Time to complete (nearest quarter) | 18 months | 9 months | 6 months |
| Cash expended (% of overnight capital) | 2% | 12% | 86% |
| Cost to suspend at end of phase ($/kW) | Negligible | $263 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $4 | -- |

[22] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

| | Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | 63 | -- |
| Cost of immediate termination ($/kW) | Negligible | $308 | -- |

## ALBERTA OIL SANDS COGENERATION

The oil sands[23] of northern Alberta contain an estimated 1.6 trillion barrels initial volume in place, the largest petroleum deposits outside the Middle East. Three major resource areas are present - Athabasca, Peace River and Cold Lake. Oil sands are comprised of unconsolidated grains of sand surrounded by a film of water and embedded in matrix of bitumen[24], water and gas (air and some methane). The mean bitumen content of Alberta oil sands ranges from 10 to 12 percent by weight. Extracted bitumen can be upgraded to a synthetic crude oil that can be processed by conventional refineries. Rising oil prices have made bitumen extraction and processing economic and production is expected to expand rapidly in coming years. Oil sands production currently comprise about one third of total Canadian oil production.

Bitumen is recovered from near-surface deposits using open pit mining followed by separation of the bitumen from the extracted oil sands. The extraction process uses hot water to separate the bitumen from the sand. About 75 percent of the bitumen is recovered and the residue is returned to the pit. Yield is about one barrel of oil for every two tons of extracted oil sands.

Bitumen from deep deposits is recovered using in-situ methods. The predominant method is steam assisted gravity drainage (SAGD). Steam is injected via injection wells to raise the temperature of the formation to the point where the bitumen will flow. The liquid bitumen is recovered using conventional production wells. It is estimated that about 80 percent of recoverable reserves will use in-situ methods.

The steam for in-situ injection can be produced using coke or natural gas-fired boilers. A more efficient approach is to cogenerate steam using gas turbine generators. Natural gas or synthetic gas derived from residuals of bitumen upgrading is used to fuel the gas turbines. Approximately 2,000 megawatts of oil sands cogeneration is in service. Additional development of electric generating capacity is constrained by limited transmission access to electricity markets. A 2,000-megawatt DC intertie from the oil sands region to the Celilo converter station near The Dalles, with intermediate converter stations near Calgary and possibly Spokane has been proposed as a means of opening markets for electricity from oil sands cogeneration. The transmission could be energized as early as 2011.

[23] Formerly known as “tar sands”.
[24] Bitumen is a heavy, solid or semi-solid black or brown hydrocarbon comprised of asphaltenes, resins and oils, soluble in organic solvents. Alberta oil sands bitumen is the consistency of cold molasses at room temperature.

## Economics

The cost of power from a gas turbine power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. In a cogeneration facility the fuel cost components are generally allocated between the cogeneration thermal load and electricity generation using a "fuel charged to power" heat rate. For a gas turbine cogeneration plant this heat rate is considerably lower than the stand-alone heat rate of the gas turbine unit. For example, the expected fuel charged to power heat rate of the proposed F-class gas turbine cogeneration units for oil sands application is 5,800 Btu per kilowatt-hour (HHV). This compares to a stand-alone HHV heat rate for an F-class machine of 10,390 Btu per kilowatt-hour. Because of the low effective heat rate and need for a constant steam supply, a gas turbine cogeneration unit will run at a high capacity factor, typically higher than a stand-alone baseload power plant. Though an 80 percent capacity factor is assumed for the benchmark costs given below, oil sands cogeneration units could operate at capacity factors of 90 to 95 percent.

The transmission costs given in Table I-16 are preliminary estimates provided by the proponents of the DC intertie. For very long distance interties, DC transmission costs are typically lower than for AC circuits. Nonetheless, the preliminary estimates appear to be low compared to the preliminary estimates for new transmission from eastern Montana. The Northwest Transmission Assessment Committee of the Northwest Power Pool will be refining these transmission estimates over the next several months.

## Development Issues

Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $43 per megawatt-hour. While slightly higher 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. Moreover, a gasification process for deriving fuel gas from oil sands processing residuals is available. This alternative fuel could further isolate oil sands cogeneration from natural gas price risk. Also, because of the lower heat rate, the incremental carbon dioxide production of cogeneration is less than for stand-alone gas-fired generation, reducing the risk associated with possible future carbon dioxide control measures.

Development of the proposed intertie, however, would present a major challenge. Transmission siting and permitting efforts in the U.S., especially for new corridors, has proven difficult. Subscription financing is proposed. While effective for financing incremental natural gas pipeline expansions, subscription for financing large-scale transmission expansions is untested. Finally, the 2,000-megawatt capacity increment is likely too large for the Northwest to accept at one time. Some means of shortening commitment lead-time, phasing project output, or selling a portion to California Utilities would improve the feasibility for development.

## Northwest Potential

The proposed DC intertie would deliver 2,000 megawatts of power to the Celilo area or to points south on the existing AC or DC interties. Whether larger increments of power are potentially available would depend upon future levels of oil sands production. Smaller, more easily integrated increments of power could be provided, but at additional cost because of transmission economies of scale. For example, a 500 kV AC transmission circuit could deliver approximately 1,000 megawatts of power. Refinement of transmission cost estimates, currently underway, will provide better estimates of the cost of various levels of development.

## Reference plant

The estimated cost and technical performance a proposed 2,000 MW DC intertie from the Alberta oil sands region to Celilo and the associated gas turbine cogeneration units have been provided to the Council by Northern Lights. Northern Lights is a subsidiary of TransCanada formed to investigate and promote the concept. The project would consist of a single-circuit +/- 500kV DC transmission line from the Ft McMurray area of Alberta to the Celilo converter station in Oregon. The line would deliver 2,000 megawatts of capacity at Celilo with an input of about 2,160 megawatts. Intermediate converter taps could be provided near Calgary and near Spokane.

Electricity would be provided by 12 F-class gas turbine generators equipped with heat recovery steam generators. Each turbine would produce about 180 megawatts of electrical capacity plus steam for in-situ recovery of oil sands bitumen. The cost and performance assumptions of Table I-16 assume use of firm pipeline natural gas as fuel. A demonstration gasification project using bitumen processing byproducts is under development. If successful, the cogeneration units could be fired using synthetic gas.

Where necessary to support the Council's modeling, the Council's generic power plant assumptions have been used to augment the information supplied by TransCanada. Because of uncertainties regarding the cost and routing of the transmission intertie, the estimates of Table I-16 are considered to be very preliminary at his point

The benchmark[25] levelized electricity production costs for the reference plant, power delivered to Celilo, are $43 per megawatt-hour.

[25] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Alberta natural gas, medium case price forecast; 90 percent capacity factor, year 2000 dollars. Based on fuel charged to power. No CO2 penalty.

**Table I-16:** Resource characterization: Alberta oil sands cogeneration and transmission intertie (Year 2000 dollars)

| **Description and technical performance** | | |
|---|---|---|
| Facility | 180 MW natural gas-fired 7F-class simple-cycle gas turbine plant with heat recovery steam generator. 2000 MW DC circuit - Ft McMurray area to Celilo. | |
| Status | Commercially mature | |
| Applications | Baseload power generation with cogenerated steam for bitumen recovery | |
| Fuel | Pipeline natural gas. Firm transportation contract with capacity release provisions. | Council's forecast Alberta firm natural gas. |
| Service life | 30 years | |
| Power (net) | 180 MW/unit | |
| Operating limits | Minimum load: n/avail<br>Cold startup: n/avail<br>Ramp rate: n/avail | |
| Availability | Equivalent annual availability: 95% | |
| Heat rate (HHV) | 5800 Btu/kWh (fuel charged to power) | |
| Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements) | -0.5 %/yr average from 2002 base through 2025 | Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation. |
| Seasonal power output (ambient air temperature sensitivity) | Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1). | |
| Elevation adjustment for power output | Included in gas turbine rating | |

| **Costs** | | |
|---|---|---|
| Capital cost | Gas turbine cogeneration units: $506/kW<br>Transmission: $621/kW | Overnight costs at 0.76 $US:$Cdn exchange rate. |
| Construction period cash flow (%/yr) | Gas turbine cogeneration units: 100% (one year construction)<br>Transmission: 18%/27%/56% (3 year construction) | See Table I-8 for phased development assumptions used in portfolio risk studies. |
| Fixed operating costs | Gas turbine cogeneration units: Inc. in variable O&M.<br>Transmission: $9.32 | |
| Variable operating costs | Gas turbine cogeneration units: $2.78/MWh<br>Transmission: $0.00 | TransCanada value net of property tax & insurance |
| Incentives/Byproduct credits/CO2 penalties | Separately included in the Council's models. | |
| Interconnection and regional transmission costs | See above. | |
| Transmission losses | 7.7% (to Celilo) | |

| Costs | | |
|---|---|---|
| Technology vintage cost change (constant dollar escalation) | Gas turbine cogeneration units: -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)<br>Transmission: None | Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation. |

| Typical air emissions (Plant site, excluding gas production & delivery) | | |
|---|---|---|
| Particulates (PM-10) | Not available | |
| SO2 | Not available | |
| NOx | Not available | |
| CO | Not available | |
| Hydrocarbons/VOC | Not available | |
| $CO_2$ | 365T/GWh | Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and fuel charged to power heat rate. Corrected for transmission losses. |

| Development | | |
|---|---|---|
| Assumed mix of developers | Benchmark mix:<br>Consumer-owned utility: 20%<br>Investor-owned utility: 40%<br>Independent power producer: 40% | Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources. |
| Development & construction schedule | Gas turbine cogeneration units:<br>Development - 18 months<br>Construction - 12 months<br>Transmission<br>Development - 48 months<br>Construction - 36 months | "Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies. |
| Earliest commercial service | 2011 | |
| Resource availability through 2025 | 2000 MW | |

## Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are defined in the portfolio risk model: project development, optional construction and committed construction. Development of Alberta oil sands cogeneration for the Northwest market would have to be structured around the long lead time and large capacity increment of the proposed 2,000 megawatt DC transmission intertie. Because phased development of the proposed DC intertie is unlikely to be practical, the generation would have to be developed within a relatively brief period in order to fully use the transmission investment. The Council assumed that development of the generating capacity would occur in two 1,000 megawatt blocks. The first would be timed for completion coincidentally with the transmission intertie. The second block would be brought into service a year later. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-17.

**Table I-17:** Alberta oil sands cogeneration and transmission intertie phased development assumptions for risk analysis (year 2000 dollars)[26]

| | Project Development | Optional Construction | Committed Construction |
|---|---|---|---|
| Defining milestones | Initiate transmission system planning | Order major transmission equipment and materials. | Delivery of major transmission equipment and materials to commercial operation of second 1000 MW block of generation. |
| Time to complete (single unit, nearest quarter) | 48 months | 12 months | 36 months |
| Cash expended (% of overnight capital) | 5% | 9% | 86% |
| Cost to suspend at end of phase ($/kW) | Negligible | $340 | -- |
| Cost to hold at end of phase ($/kW/yr) | $1 | $13 | -- |
| Maximum hold time from end of phase | 60 months | 60 months | -- |
| Cost of termination following suspension ($/kW) | Negligible | -$74 | -- |
| Cost of immediate termination ($/kW) | Negligible | -$259 | -- |

[26] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

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# Carbon Dioxide Sequestration

Industrial-scale processes are available for separating carbon dioxide from the post-combustion flue gas of a steam-electric power plant or from the synthesis gas fuel of a coal gasification power plant. The separated carbon dioxide can be compressed and transported by pipeline for injection into suitable geologic formations for permanent storage (“sequestration”).

Commercialization of coal-fired gasification power plants (Appendix I) is expected to boost the prospects for carbon dioxide separation and sequestration because the lower cost of carbon dioxide separation from the relatively low volume of pressurized synthesis gas fuel of a gasification plant compared to the cost of partitioning carbon dioxide from the much greater volume of steam-electric plant flue gas. Carbon dioxide can be separated using the sorbent processes currently used to remove sulfur compounds from the synthesis gas of existing gasification plants used for chemical production. Selective regenerative sorbent technology is capable of separating up to 90 percent of the carbon dioxide content of raw synthesis gas. The carbon dioxide would than be compressed to its high-density supercritical phase for pipeline transport to sequestration sites.

This process is in commercial operation at the Great Plains Synfuels Plant in central North Dakota. Here, carbon dioxide is separated, compressed and transported 205 miles by pipeline to Weyburn, Saskachewan where it is injected for enhanced oil recovery. Solvent-based regenerative processes are energy-intensive and would lower the thermal efficiency of coal gasification power plants. Selective separation membrane technology would reduce the energy requirements of carbon dioxide separation. Research, mostly at the theoretical or laboratory stage is underway for the development of selective separation membrane technology suitable for withstanding the operating conditions of a coal gasification power plant.

Among the sequestration alternatives being considered are depleted or depleting oil and gas reservoirs, unmineable coal seams, salt domes, deep saline aquifers and deep ocean disposal. Proven technology is available for injection of carbon dioxide into oil or gas-bearing formations. An advantage of sequestration involving enhanced recovery of gas, oil or coalbed methane is the byproduct value of the recovered oil or gas. Moreover, coal is often found in the general vicinity of oil or gas-bearing formations, which could reduce carbon dioxide transportation cost. Saline formations suitable for sequestration are widespread, and could also use existing injection technology, though there would be no byproduct value. Because the primary objective of existing carbon dioxide injection operations has been enhanced oil or gas recovery rather than carbon dioxide storage, additional development of monitoring capability and processes for verifying the integrity of geologic carbon dioxide disposal sites is needed.

Preliminary assessment of the costs of carbon dioxide transportation and storage range from \$1.00 to over \$16/tonCO2 for a power plant located near suitable depleted oil or gas reservoirs or saline aquifers (Table K-1)[1]. These estimates do not include the possible byproduct value of

[1] Heddle, Gemma, et al. The Economics of Carbon Dioxide Storage (MIT LFEE 2003-003 RP). MIT Laboratory for Energy and the Environment. August 2003.

enhanced oil or gas recovery. The report from which the values of Table K-1 were obtained also examined the cost of ocean disposal of carbon dioxide. These estimates were omitted from Table K-1 because the feasibility of ocean disposal appears to be speculative at this time.

Deep saline aquifers and bedded salt formations potentially suited for carbon dioxide sequestration are present in eastern Montana. The US DOE has provided matching funds to establish several Regional Carbon Sequestration Partnerships. These include the Northern Rockies and Great Plains partnership, led by Montana State University. This group will identify carbon dioxide sources and promising geologic and terrestrial storage sites in Montana, Idaho and South Dakota. The West Coast Regional partnership, led by the California Energy Commission will pursue similar objectives in the West Coast states, Arizona and Nevada.

**Table K-1: Estimated costs for transporting & storing 7389 tonnes (8146 Tons) carbon dioxide per day ($/TonCO2, year 2000$)[2]**

| | | |
|---|---|---|
| **Depleted gas reservoir** | | |
| Base | Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 5000 ft injection wells. No recompression. | $4.10 |
| Low cost | Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 2000 ft injection wells. No recompression. | $1.00 |
| High cost | Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 10,000 ft injection wells. No recompression. | $16.30 |
| **Depleted oil reservoir** | | |
| Base | Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 5100 ft injection wells. No recompression. | $3.20 |
| Low cost | Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 5000 ft injection wells. No recompression. | $1.00 |
| High cost | Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 7000 ft injection wells. No recompression. | $9.40 |
| **Saline aquifer** | | |
| Base | Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 4100 ft injection wells. No recompression. | $2.50 |
| Low cost | Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 2300 ft injection wells. No recompression. | $1.00 |
| High cost | Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 5600 ft injection wells. No recompression. | $9.80 |

2 Estimates exclude separation costs and possible byproduct credit from enhanced gas or oil recovery.

# The Portfolio Model

## *Introduction*

The portfolio model is a simple Excel worksheet that calculates energy and costs associated with meeting regional requirements for electricity. The energy and costs are for a single plan under a specific future.[1] As described in Chapter 6, estimating costs for a plan under many futures is necessary in order to obtain a likelihood distribution for cost. Preparing the feasibility space and efficient frontier, in turn, require the evaluation of many plans. Part of the objective of this appendix is to explain how the portfolio model works within other applications to achieve the goal of creating the feasibility space.

This appendix begins with a description of portfolio model principles. A flow diagram of the overall modeling process orients the reader to where the portfolio model fits into the process. The flow diagram shows that *period-specific* calculations are the lowest-level and simplest calculations in the workbook, providing a starting place for the detailed description of the model. (See "Single Period," beginning on page L-11.) The *period-specific* section also outlines the model's approach to calculating costs. Certain aspects of uncertainty and portfolio element behavior require a consideration of what is happening over time and how events in one period affect those in subsequent periods. In the section "Multiple Periods" on page L-58, the appendix discusses the inter-period nature of correlations and behaviors. This section also addresses the operation of smelters, the construction of new resources, and other activities that rely on events over multiple periods.

It is important to note that a portion of the description of the portfolio model is in Appendix P, instead of here in Appendix L. The treatment of uncertainties, like load and hydro generation, are to some extent separable from the rest of the model. (This appendix identifies a particular range of the model worksheet that creates the futures later in this introduction, on page L-10.) Because the description of uncertainties appears in Appendix P, it makes sense to describe the regional model's treatment of those uncertainties in the same place. This appendix provides additional explanation wherever the uncertainties bear on the aspects of the model discussed here.

The section "Resource Implementation and Data," beginning on page L-92, presents the rationale and references for most of the model's data. The section identifies key parameters for existing and candidate generation resources, system benefit charge (SBC) wind additions, and contract imports and exports. It also discusses the characteristics and treatment of independent power producers (IPPs).

[1] Chapter 6 defines the terms "plan," "future," and "scenario" and provides examples. The glossary of this appendix includes brief definitions.

The appendix next describes the Council's modeling efforts. It illustrates how the Crystal Ball® Monte Carlo games are prepared and how the OptQuest™ stochastic optimization application is configured. The appendix lists some special utilities that extract data, prepare reports, and assist users to verify calculations. It summarizes the insights the Council has obtained through application of these tools and provides, in particular, an explanation of the value of conservation under uncertainty, which deterministic models fail to capture.

The appendix concludes with an introduction to ***Olivia***, the meta-model that created the regional portfolio model. ***Olivia*** creates Crystal Ball-aware Excel workbooks ready for use under Crystal Ball and OptQuest or for stand-alone use. ***Olivia*** is available free to any individual or agency that wants to create a portfolio or risk model describing their unique situation.

The reader may want to consult the following Table of Contents for orientation to the remaining appendix.

## Table of Contents

# Principles

The portfolio model is a simple calculation engine. For a given plan, it estimates costs of generation, of wholesale power purchases and sales, and of capacity expansion over the 20-year study under a particular future. An Excel add-in, Decisioneering Inc.'s Crystal Ball, runs a Monte Carlo simulation, with each game corresponding to a future, compelling the portfolio model to recalculate for each future. The portfolio model takes each future and determines the energies and costs associated with that future. A second Excel add-in finds least-cost, risk constrained plans using stochastic, non-linear optimization techniques.

Figure L-1 illustrates the kind of calculation that the portfolio model makes in a specific scenario. It shows energy use resulting from a plan over a two-year period for the fixed future. A future defines the hydro generation, loads, gas prices, and so forth in each hour. Existing and future resources in the plan generate power, largely in response to wholesale electricity prices. Because generation rarely exactly matches load, a load serving entity must buy power from the wholesale market or sell into the wholesale market. The costs and revenues in each hour add to any future fixed costs for existing and new generation or capital costs for new generation and conservation. The model discounts these cash flows to the beginning of the study. Of course, the portfolio model does this for 20 years, not for two years, but the process is identical.

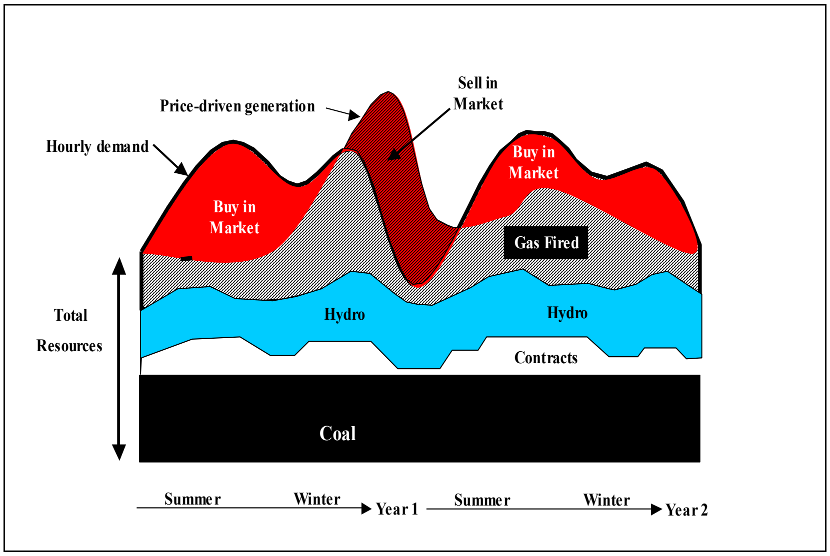



**Figure L-1: Portfolio Model Calculation**

The model evaluates 750 futures for each plan and about 1,400 plans per study, for a total of around a million scenarios. An hourly calculation for each of these 20-year scenarios would be prohibitive.[2] For this reason, the model uses special algorithms to estimate plant capacity factors, generation, and costs for periods of three months. The 20-year study period is represented by 80 hydro-year quarters on peak and another 80 off peak. The model does not break the Northwest into sub-regions. Consequently, there is no explicit treatment of cross-Cascade and other intra-regional transmission constraints. The model, however, does constrain imports and exports to 6,000 megawatt-quarters, before any contracts.[3] Transmission constraints within the region are considered outside the model. Existing regional thermal resources

[2] One estimate using AURORA® run times put the study at a little over 85 years.
[3] Contracts may be fully counter-scheduled.

are aggregated down to about 30 plants with similar characteristics. A 50-year streamflow record and 2000 Biological Opinion (BiOp) constraints on operations determine possible hydro generation. Operation of the region's seven remaining smelters depends the relative price of aluminum and wholesale electricity.

One of the things that make the portfolio models particularly simple is its construction in an Excel worksheet. Most analysts know how to read and modify an Excel worksheet. Columns in the worksheet denote periods, and rows contain information about loads and resources. Although simple to interpret, however, there are many calculations in the regional portfolio worksheet. In addition, special purpose Excel functions perform much of work, and the model carefully controls calculation order within worksheets. These issues require explanation.

To help the reader understand how the model works, therefore, its description will proceed in two steps. The first step will describe calculations that pertained to a single period. These include, for example, estimating thermal generation and costs for a given period. They will also cover some simple resources, such as contracts and hydrogeneration defined by streamflow. Balancing load requirements and generation with electricity price adjustments is another process that takes place within a single period. The second step will describe calculations involving several periods. This includes price processes, and the description of underlying trends for natural gas price and loads. This also includes more complex load and resource behaviors, such as decisions to shut down or restart a smelter and the rules for adding new resources to the system, such as those that govern whether or not to proceed with the construction of power generation resources.

| ICON KEY |
|---|
| Key idea |
| Definition |

This appendix provides several tools to help the reader track this discussion. The first tool is the use of icons to flag key definitions and concepts. A table of these icons appears that the left. The second tool is a workbook, L24DW02-f06-P.xls, containing a pre-draft plan version the regional portfolio model. The reader can request a copy of the workbook from the Council or download a copy of this workbook from the Council's web site ( http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/L24X-DW02-P.zip ). References to the workbook L24DW02-f06-P.xls appear in curly brackets ("{}"). Understanding the description does not require reference to the workbook, however. References to Council data sources appear in square brackets ("[]"). The References section at the end of the appendix lists these sources. Publicly available sources appear in footnotes.

To motivate the description of the portfolio model that appears here, discussion next turns to the logic structure of the portfolio model. The model calculation follows a specific order, with columns within certain ranges calculated in order. The strict order of calculation reflects the passage of time and the cause and effect of prior periods on subsequent periods. It also suggests why some calculations are best understood in terms of behaviors within a single period and others require understanding processes that span multiple periods.

## Logic Structure

When a user opens the portfolio model workbook, the values they see are values for a particular future and for a particular plan. It is within this future (or game) that the energy and cost calculations take place. How, then, are the futures changed to create a cost distribution for a plan and the plans changed to create the feasibility space?

Figure L-2 illustrates the overall logic structure for the modeling process. The optimization application, the OptQuest Excel add-in, controls the outer-most loop. The goal of the outer-most loop is to determine the least-cost plan for each level of risk. It does so by starting with an arbitrary plan, determining its cost and risk, and refining the plan until refinements no longer yield improvements. The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with equal (or lower) risk but lower cost. The process ends when we have found a least-cost plan for each level of risk. This process is a form of non-linear stochastic optimization. The interested reader can find a more complete, mathematical description of the optimization logic in reference [**1**].

In terms of the worksheet model, the optimizer OptQuest controls the Crystal Ball Excel add-in. OptQuest hands a plan to Crystal Ball, which manifests the plan by setting the values of "decision cells[4]" in the worksheet. These are the yellow cells in {range R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop, labeled "Monte Carlo Simulation," in Figure L-2. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest. For each future, Crystal Ball assigns random values[5] to 1045 "assumption cells." These assumption cells appear as dark green cells throughout the worksheet. (See for example, {R24}.) Crystal Ball then recalculates the workbook. In the portfolio model, however, automatic recalculation is undesirable, as described on page L-9. The portfolio model therefore substitutes its own calculation scheme. It uses a special Crystal Ball feature that permits users to insert their own macros into the simulation cycle, as shown in Figure L-3. Before Crystal Ball gets results from the worksheet, a macro recalculates energy and cost, period by period, in the strict order illustrated in Figure L-4 and described on page L-9. The values in the Crystal Ball "forecast cells" then contain final net present value (NPV) costs that Crystal Ball saves until the end of the simulation. Forecast cells are those that have the simulation results and have a bright blue color. The NPV cost, for example, is in {CV1045}.

---

[4] "Decision cell," "assumption cell," and "forecast cell" are Crystal Ball terms. The glossary at the end of this appendix defines each. This appendix details the function and application of decision cells in the section "Parameters Describing the Plan," page L-72. Appendix P describes "assumption cells."

[5] For a number of good reasons, these values are not truly random in the everyday sense of the word. For example, the random number generator uses a seed value, so that an analyst can reproduce each future exactly for subsequent study. The generator also selects the values to provide a more representative sampling of the underlying distribution, a technique known as Latin Hyper Square or Latin Hyper Cube.

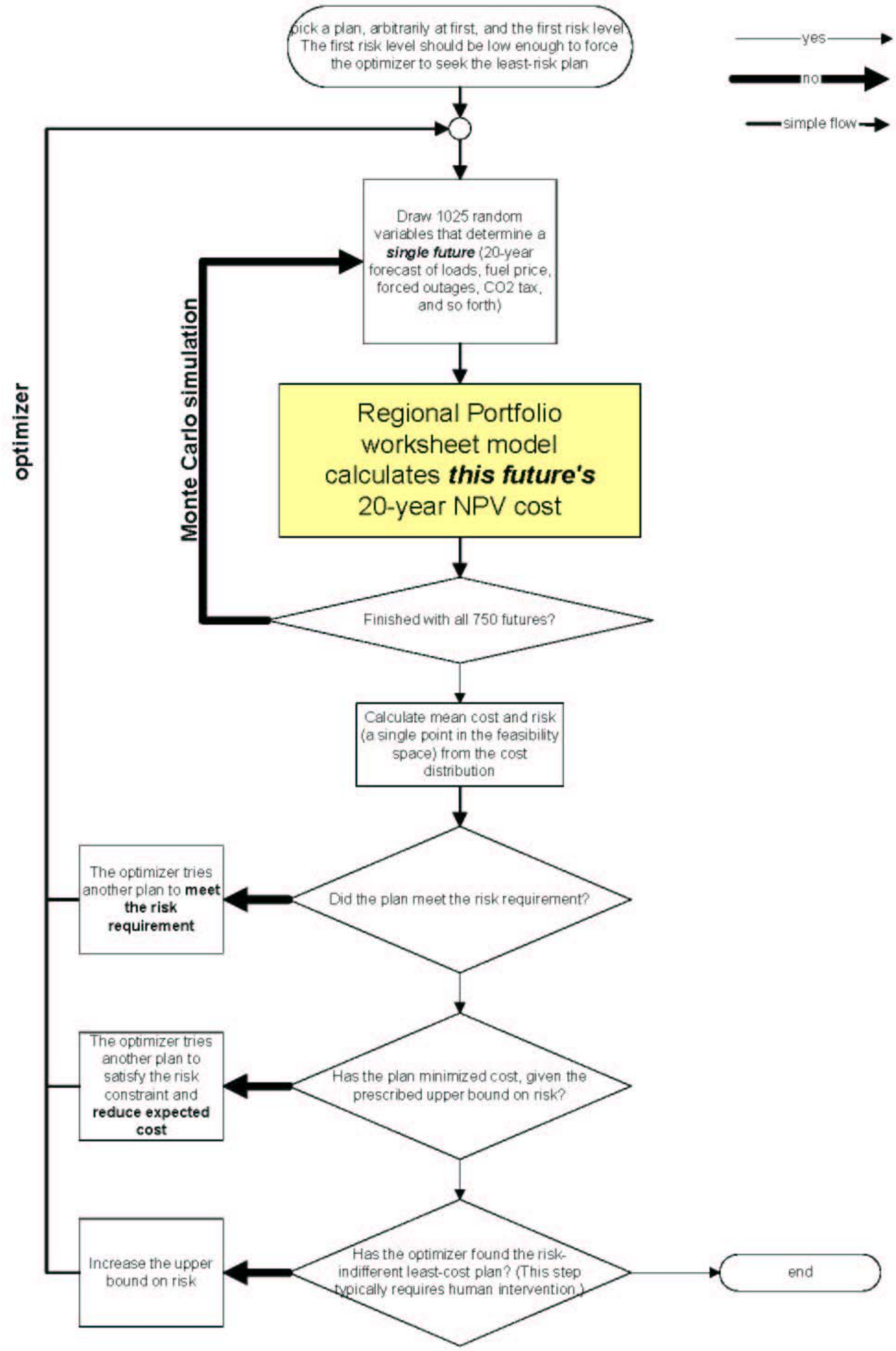



**Figure L-2: Logic Flow for Overall Risk Modeling**

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the last macro in Figure L-3 fires. This macro calculates the custom risk measures and updates their forecast cells. The custom risk measures include, for example, TailVaR$_{90}$, CVaR$_{20000}$, VaR$_{90}$, and the 90$^{th}$ Quintile.

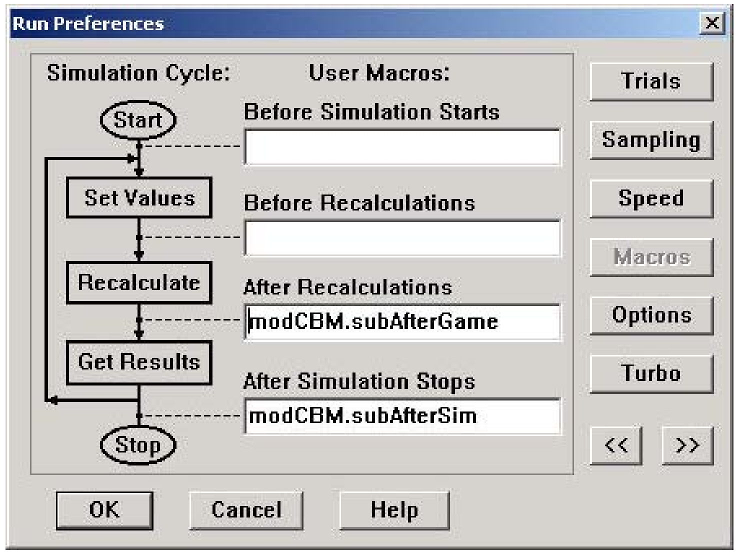



**Figure L-3: Crystal Balls Macro Loop**

One of the capabilities of Crystal Ball is distributed computation. Under its "Turbo Mode," Crystal Ball on a "master" machine packages bundles of several games and sends a bundle to each "worker" machine in a network, as illustrated in Figure L-5. After the bundle of games is complete, the worker sends back the results and requests another bundle. When all the games are finished, Crystal Ball evaluates the simulation results and returns required data to OptQuest. The Council uses nine 3-GHz Pentium 3 "worker" machines in a dedicated network, together with a 3-GHz Pentium 3 "master" and a server that coordinates the flow of bundles.

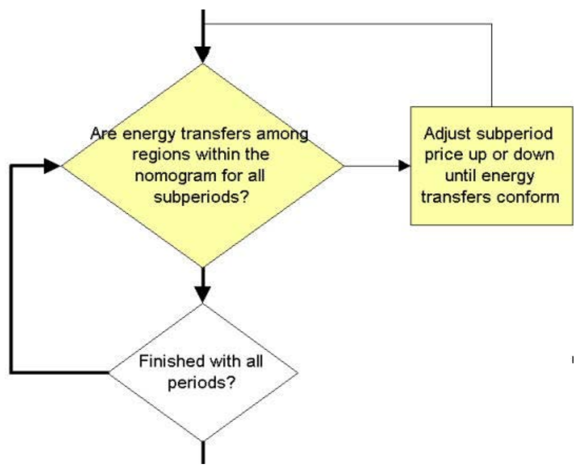



**Figure L-4: Logic in the Regional Portfolio Worksheet Model**



***The portfolio model performs the duties of the innermost task, identified by the shaded box in Figure L-2.*** Given the values of random variables in assumption cells, the portfolio model constructs the futures, such as paths and jumps for load and gas price, forced outages for power plants, and aluminum prices over the 20-year study period. It does this only once per game. It then balances energy for each period, on- and off-peak and among areas, by adjusting the electricity price. The regional portfolio model uses only two areas, however, the region and the "rest of the interconnected system." Only after it iterates to a feasible solution for electricity price in one period does the calculation moves on to the next period. After calculating price, energy, and cost for each period, the model then determines the NPV cost of each portfolio element and sums those to obtain the system NPV. This sum is in a forecast cell.

There is a special step in the above process to recalculate the cells that control the long-term interaction of futures, prices, and resources, referred to here as the "Twilight Zone." This portion of the worksheet contains, for example, formulas for price elasticity of load and decision criteria. The workbook recalculates this portion of the worksheet multiple times for each subperiod.

Excel workbooks use an internal "recalculation tree" to determine which cells need recalculation when the user modifies any Excel worksheet.[6] If the workbook containing this worksheet is in automatic recalculation mode, the change will trigger a search of the tree, and Excel recalculates only the affected cells. This usually saves a great deal of time. It also explains why an Excel workbook initially may require 30 seconds to calculate when loaded but only an instant when a user makes certain changes.

The portfolio model worksheet, however, must solve several energy balancing problems by iteration, illustrated in Figure L-4. (The details of this process are in the section "RRP algorithm," which begins on page L-51.) This process proceeds from the earliest period (far left column {column R}) to the last period (far right column {column CS}). Under automatic calculation, the cells involved in iterative recalculation would not only influence a large number of "down stream" calculations but would cause dependent user-defined functions to fire, as well. These down stream recalculations could take significant amounts of time. Moreover, the energy rebalancing calculation finally discards the values of the down-stream cells, because the workbook must eventually recalculate those values anew. For this reason, the model turns off automatic calculation. The model instead controls the recalculation of all cells with a VBA range recalculation.

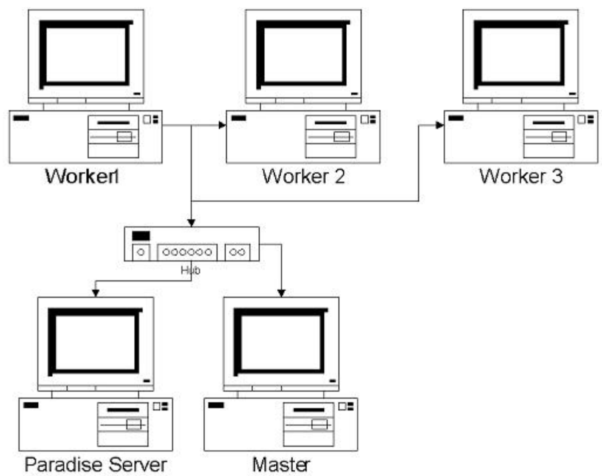



**Figure L-5: Distributed Processing**

Figure L-6 illustrates the calculation order described above. The number in the parentheses is the order. The plus sign (+) is a reminder that iterative calculations take place in the area. Calculations made only once per game are near the top of the worksheet {rows 26-201}. The illustration denotes those recalculations that must be made multiple times per subperiod by TLZ {rows 202-321}. NP stands for on-peak

[6] The reader can find a description of the Excel recalculation method at http://msdn.microsoft.com/library/default.asp?url=/library/en-us/dnexcl2k2/html/odc_xlrecalc.asp

{rows 318-682}; FP stands for off-peak {rows 684-1058}. The area at the far right refers to the NPV summary calculations {range CU318:CV1045}.

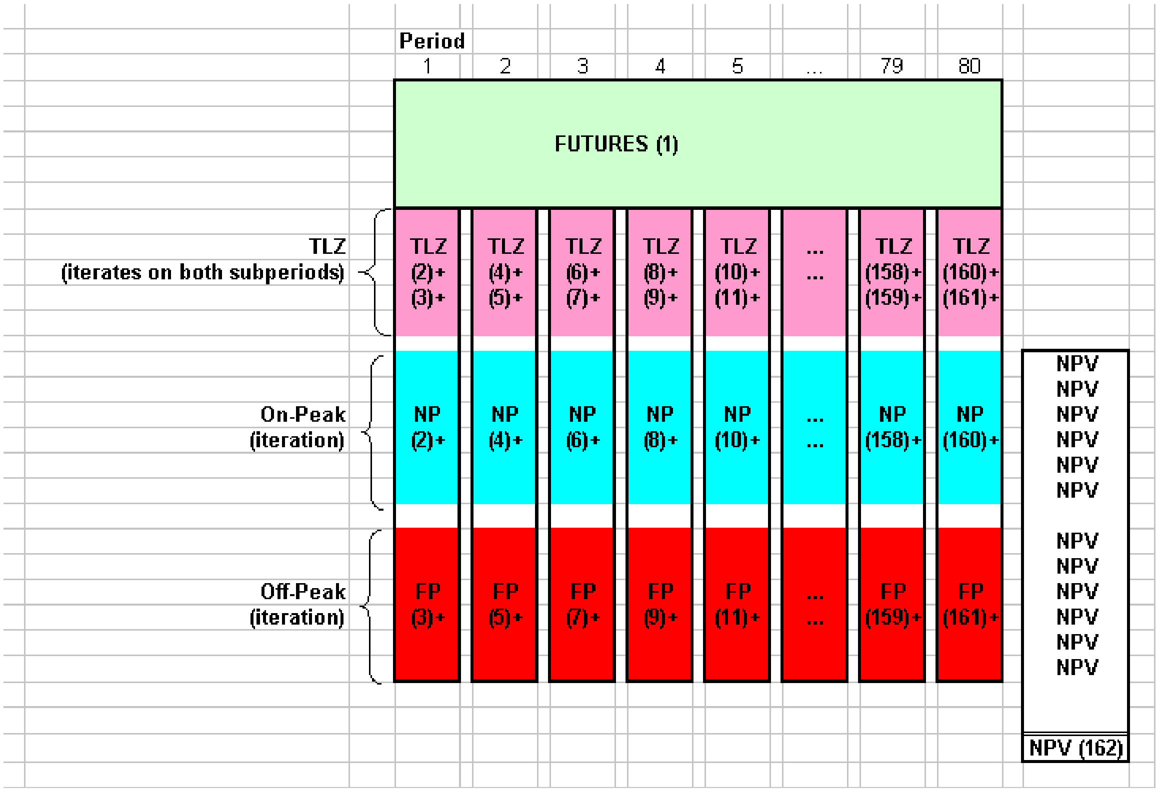



**Figure L-6: Portfolio Model Calculation Order**

Appendix P documents the uncertainties in the regional portfolio model. This includes the worksheet formulas for describing the uncertainties. Because it would be redundant to cover the same material in this appendix, the scope of this appendix is everything *except* the uncertainties.



Figure L-6 permits us to state the scope of this appendix with respect to ranges within of the portfolio model. Appendix P describes the calculations in the area of the worksheet denoted by “FUTURES (1)”. This Appendix L discusses all remaining areas.

With this overview, this appendix starts the detailed description of the regional model with perhaps the simplest area of calculation in the workbook, the single period. The calculations within a single period are to a certain extent independent of each other. They are the building blocks for more involved behaviors that span multiple periods. They also are the province of rich behavior and some of the most novel algorithms.

## Single Period

This section considers only a single period in the study timeframe, December 1, 2009, through February 28, 2010 {column AQ}. There is nothing special about this period; any other period would do. Logic is identical across periods.

The portfolio model aggregates time into periods. The primary purpose for this is to achieve efficiencies in calculating energy generation and costs. Annual periods do not capture interesting seasonal behavior, and using monthly calculations do not provide any benefit over quarterly calculations. Because hydrogeneration determines much of the resource behavior in the Pacific Northwest, the model uses hydro quarters. For the purposes of the portfolio model, the hydro-year begins September 1, so the quarters are September through November, December through February, March through May, and June through August. This appendix will occasionally refer to these as the autumn, winter, spring, and summer quarters.

One of the distinctive features of the portfolio model is how it defines periods in terms of hours. A **standard month** is exactly four weeks. Similarly, a **standard quarter** is three standard months, and a **standard year** is four standard quarters. A standard month has exactly four weeks. By adopting this convention the number of hours on peak[7] and off peak in each month, quarter[8], and year are fixed and uniform. Consequently, conversion calculations to MWh from average megawatts are the same across all periods. In addition, shifting patterns of holidays and Sundays from month to month and year to year do not create misleading results due only to that kind of variation.

Because the periods in the portfolio are rather long, the ratio of on and off-peak hours using standard quarters are close to those the model would have obtained had the model not used standard quarters. Consequently, the regional portfolio model keeps costs in standard time units and simply scales up the results in the net present value calculation. For example, see {row 323, column CV}, where the model ratios up the costs by the ratio of hours in a non-leap year to the hours in a standard year, 8760/8064, or about 8.63 percent.

This convention does introduce one source of additional complexity, however. It requires that the model handle fixed costs carefully. Resource economics, and economic resource selection in particular, depends on the relationship between fixed and variable costs. Fixed costs are often denominated in units such as dollars per kilowatt-year ($/kWyr). The regional portfolio model uses dollars per kilowatt-standard year ($/kWstdyr), which is smaller by about 7.95 percent (1-8064/8760). If an analyst wished to scale fixed costs by the number of hour in a particular month and year, however, any fixed costs would scale appropriately. The detailed explanation of fixed costs under this convention appears on page L-69, where this appendix deals with “New Resources, Capital Costs.”

[7] The portfolio model assumes a 6x16 convention for on-peak hours. That is, on peak is defined as hours 7 through 22 (6 AM to 10 PM) each weekday and Saturday. The remaining hours are off-peak.
[8] There are 1152 on-peak hours (6x16x4x3) each quarter and 864 off-peak hours.

**Table L-1: Plan DW02**

Conservation: $10/MWh higher on the supply curve in all periods, for both non-lost opportunity and discretionary conservation.[9]
Earliest construction start dates for the following increments of resource:
CCCT: 610 MW in 12/2009
SCCT: 100 MW in 12/2019,
Wind Power Plants: 1200MW in 12/2009, 1300MW in 12/2015, 2000MW in 12/2017, 400MW in 12/2019
Coal-Fired Power Plants: 400 MW in 12/2009
Demand Response: 500MW in 12/2007, 250MW in 12/2009, 250MW in 12/2011, 250MW in 12/2013, 250MW in 12/2015, 250MW in 12/2017, and 250MW in 12/2019
Critical Water threshold for resource additions: 3000 MWa

If an analyst needed to know the energy and costs associated with a particular calendar month and year, using standard months, quarters, and years makes recovering this information easy. The model effectively determines costs by normalizing energy and cost to rates of energy per hour (power in MW) and costs per hour ($/MWh and $/kWh), and then multiplying by the fixed number of hours in each standard subperiod.

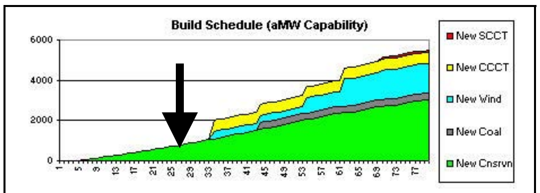



**Figure L-7: Build 0ut of Future 6**

Recovering a month and year's actual energy and cost amounts to rescaling by the month and year's actual hours per each subperiod. If the user wished to, the portfolio model could rescale before discounting of costs in the total system cost calculation.

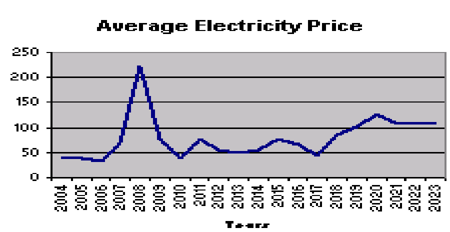



**Figure L-8: Electricity Price Future**

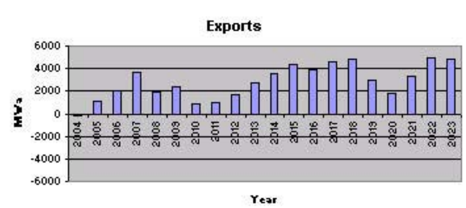



**Figure L-9: Exports**

[9] The description of this element in the decision criterion for conservation appears in Chapter 6 and under the section "Decision Criteria" that appears later in this appendix.

In addition to specifying the period that serves as our example, this description will assume a specific plan under a specific future.[10] Working with specific choices should make the calculations more concrete and easy to follow. The plan appears in Table L-1. The behavior of this plan under the 750 futures is illustrated in the workbook L24X-DW02-P.xls. The behavior of this plan under future number six appears in Figure L-7 and the details are in L24DW02-f06-P.xls. The figure contains an arrow that identifies the period under consideration. This plan is not the Council's recommended plan but illustrates some interesting behavior for the reader. Figure L-8 through Figure L-12 show other aspects of future six and the behavior of this plan under future six.

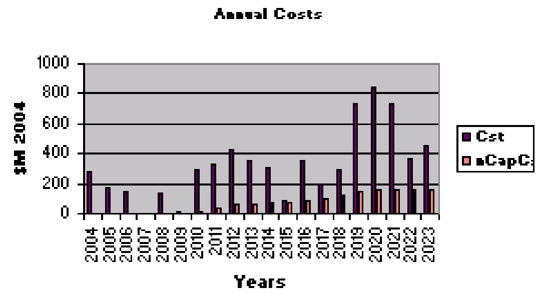



Figure L-10: Total Annual Costs and Capital Costs Only

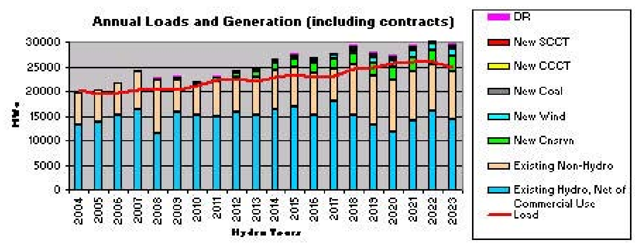



Figure L-12: Annual Energy Generation and Load

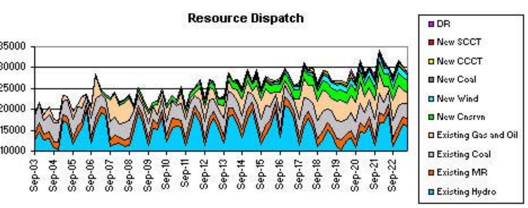



Figure L-11: Quarterly Energy Generation

The portfolio model NPV cost includes both variable and fixed components of system cost. The variable component includes total fuel, variable O&M, spot market purchases and sales, and the value of purchase contracts in the electricity market. (See the section "Contracts" for a more detailed discussion of contract costing.) The fixed component includes conservation costs and new plant incremental fixed O&M and construction cost.[11] The portfolio model uses special treatments of fixed and variable costs. The following section addresses the treatment of variable costs in the model; the subsequent section discusses fixed costs.

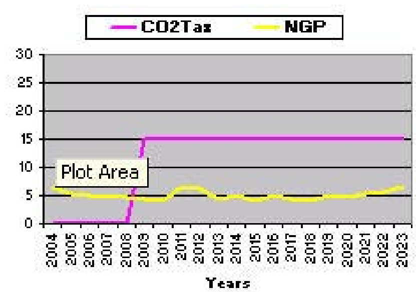



Figure L-13: Natural Gas Price and $CO_2$ penalty

## Valuation Costing

The portfolio model estimates period variable costs, such as hourly market purchases of electricity for a month, from average values over the period. Period costs can be tricky to estimate, however, because of the intra-period correlations that exist between relevant variables, such as market price for electricity and hourly requirements. For example, consider two simplified systems, System A and System B, which face the same market price over some period, say a week. (See Figure L-14.) The

[10] Chapter 6 provides definitions for the terms "future," "plan," and "scenario."

[11] Because the regional version of the portfolio model does not perform economic retirement, the model considers the incremental fixed O&M of existing plants sunk and does not include it.

task is to calculate the cost of market purchases. Even if both systems have average zero net position (resources-loads), they can have a non-zero cost. Not only this, but depending on the hourly correlation of their position with market price, the cost may be negative or positive. Clearly then, a calculation using average prices and positions is misleading. A simple illustration will demonstrate how this arises.

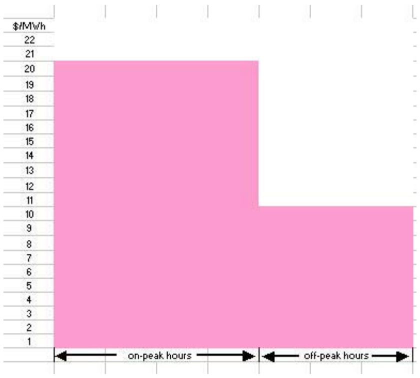



**Figure L-14: Prices over on- and off-peak hours**

The market price consists of a constant on-peak price of $20/MWh and a constant off-peak price of $10/MWh, as illustrated in Figure L-14. Although the on- and off-peak periods would alternate daily, the illustration aggregates the corresponding hours to simplify the calculation. The on-peak hours are 4/7 of the total number of hours. System A has loads -- constant over the subperiods -- shown as the heavy line in Figure L-15. The load is 2000 MW on peak and 1300 MW off peak, averaging 1700 MW over the week. System A has a constant, flat existing resource of 1700 MW, which results in a deficit on peak and a surplus off peak. The level of the source is shown by the cross-hatched area in Figure L-15. A simple calculation shows the net cost of market purchases over the week is $119,000.

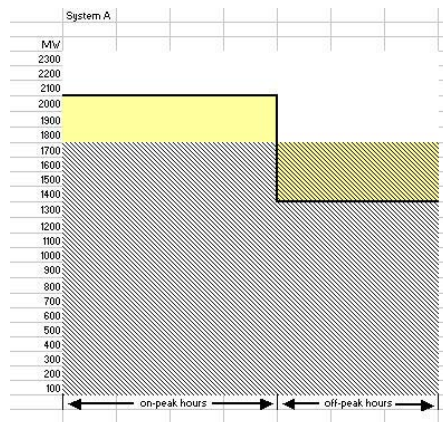



**Figure L-15: System A**

The System B has hydro generation (the cross-hatch area in Figure L-16) that is equal to loads on average, but surplus to its needs on peak. Again, using averages across the week, the cost of market purchases would be zero. System B, however, has 2300 MW on peak hydro generation and 900 MW off peak. Now the position has the opposite correlation to market price. The net cost of market purchases over the week is now negative, that is, there is a net $119,000 net benefit selling power into the market over the week.

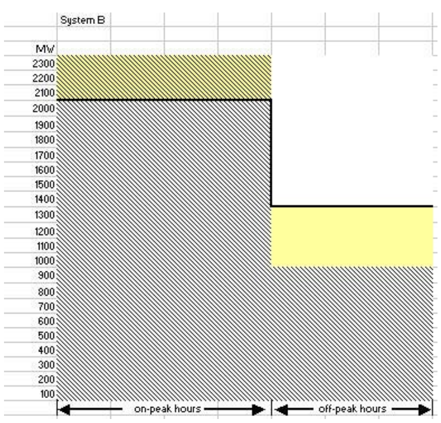



**Figure L-16: System B**

To make these results more general, the expected revenue given average price, average position, and their correlation is



$$E(pq) = E(p)E(q) + \sigma_p \sigma_q \rho_{pq} \qquad (1)$$

where ***p*** denotes hourly price, ***q*** represents hourly position, ***E(pq)*** is expected revenue, ***E(q)*** is average position, ***E(p)*** is average price, $\boldsymbol{\sigma_p}$ is the standard deviation of price, $\boldsymbol{\sigma_q}$ is the standard deviation of position, and $\boldsymbol{\rho_{pq}}$ is the correlation between price and position. This is an estimate of revenue that the portfolio model uses is several calculations.

The more general situation, of course, is more challenging. Costs and revenues for power plants potentially include a complicated and time-varying set of correlations. For example, a gas-fired power plant revenue involves not only correlation of production to electricity prices, but of production to gas prices, and of gas prices to electricity. This situation would exist for each resource. Fortunately, there is a computational short cut available.

Instead of calculating costs using all the various cross-correlations, there is an easier calculation that involves only comparisons to the electricity market. To see this, we start with a “rate base” cost calculation:

$$c = \sum_i q_i p_i + p_m (Q - \sum_i q_i) \qquad (2)$$

$c$ is total cost ($)

$q_i$ is quantity (MWh) provided by resource $i$

$p_i$ is the price ($/MWh) of resource $i$

$p_m$ is the price ($/MWh) for wholesale energy

$Q$ is total requirement

In this calculation, the variables represent hourly values. This calculation sums up the operating costs for each of the generating units and adds to that sum the cost of meeting the remaining load in the market. The problem is that $\boldsymbol{p_m}$ and ***(Q-Σq<sub></sub>)*** are correlated within a period, but the correlation is complex. Estimating $\boldsymbol{\Sigma q_i}$ alone involves knowledge of how the production among resources are correlated. Moreover, the relationship between the load Q and $\Sigma q_i$ must be calculated. By rearranging terms, however, another calculation for costs emerges.

$$
\begin{aligned}
c &= \sum_i q_i p_i + p_m \left(Q - \sum_i q_i\right) \\
&= p_m Q - p_m \sum_i q_i + \sum_i q_i * p_i \\
&= p_m Q - \sum_i q_i (p_m - p_i)
\end{aligned}
$$



This is the "valuation" cost estimate. The name stems from the fact that the load and each resource are valued in the electricity market. The first term in the last equation is the cost of meeting total load in the market. The second term is the sum of the resource values in the market.

The valuation formula simplifies the cost calculation, because we only have to consider how each resource's cost and dispatch relate to market price, rather than to other resources. For example, wind generation, conservation, and many other resources do not dispatch to market price. This mean their correlations to electric market price are zero, and multiplying average period energy by average electricity price yields expected revenues. Thermal generation, however, is a more complex situation. Thermal plants only have value when market prices exceed the variable generation price for the plant. Both market prices and fuel prices are variable within a period such as a month, and fuel prices may correlate with market prices. Fortunately, a well-understood equation provides an estimate of value in the market. This equation is precisely the topic of the section "Thermal Generation." Because such tricks exist for valuing the individual resources in the market, the valuation approach therefore significantly simplifies estimating system costs.

This concludes the description of variable cost estimation. The next section is on fixed cost treatment.

## Real Levelized Costs

The model uses the real levelized (RL) representation of fixed costs, including fixed O&M, fixed fuel, fixed transmission, and construction costs. This section describes the rationale for that choice of representation.

### Discounted Cash Flow Inadequate for Comparison[12]

Traditional engineering economics calls for life-cycle cost evaluation, taking into account risk, inflation, and the cost of money. This approach uses nominal cash flows associated with cost and benefit in each period of the analysis, and it discounts the period net cash flows to some fixed point in time. An equivalent approach uses cash flow stated in "real" or constant-year dollars and discounts by a rate that has inflation removed. This

[12] This section borrows heavily from the especially well-written description of real levelized costs that appears in PacifiCorp's 1992 Integrated Resource Plan, Appendix K.

approach is often referred to as the discounted cash flow (DCF) approach, irrespective of whether current or constant dollars are involved.

The DCF approach is limited in its ability to adequately compare one type of resource asset against another or to compare resources that employ distinct financing mechanisms. The latter is a problem perhaps unique to a regional analysis, which must address the economics of resources using rate-base cost recovery, non-utility equity investment, and the pure debt financing done by BPA, PUDs, and Co-ops.

Consider the problem comparing resources with lives of different lengths, or if the resources are placed in service in different years. For example, the design life of a new pulverized coal generating plant is 40 years, while a simple cycle combustion turbine is 25 years. Ratebase costing results in resource cost that is largest at the beginning of the asset life and declines over time as ratebase is depreciated. Capital resource cost includes depreciation expense, return on ratebase, income taxes and property taxes. Figure L-17depicts the nominal capital resource costs for a $100,000 asset with a 40-year depreciation life and for a $100,000 asset with a 25-year depreciation life.

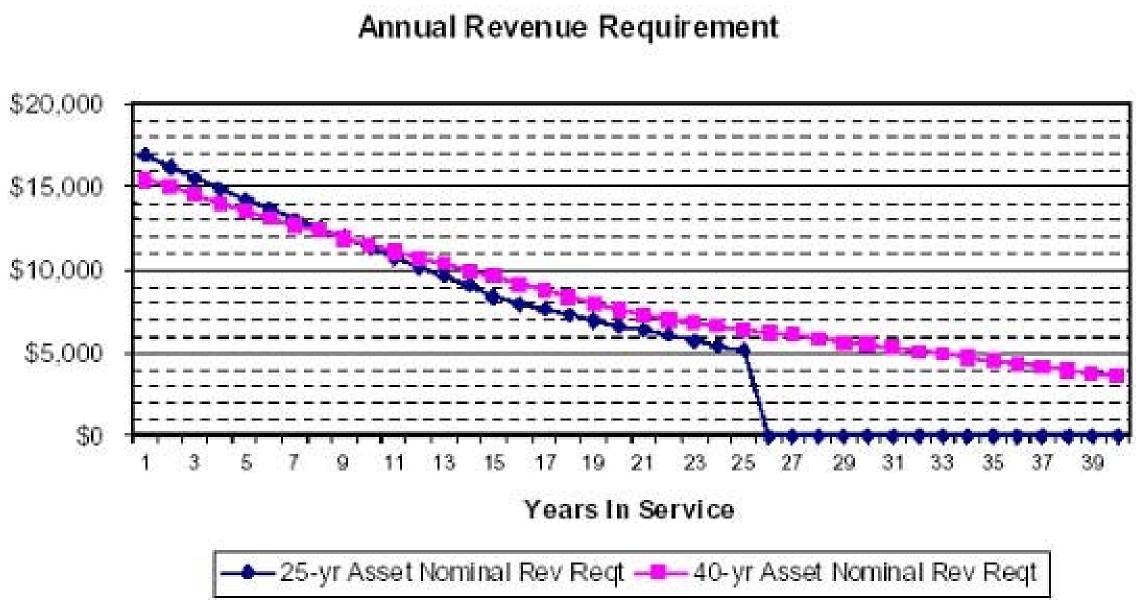



**Figure L-17: IOU Revenue Requirements**

An analysis mismatch occurs unless the analysis incorporates an adjustment for end-life effects. The “end effect” adjustment recognizes that the 25-year plant must be replaced earlier than the 40-year plant. The adjustment is a continuation of costs with those of the replacement unit. Of course, there must be a similar end-effect adjustment after 40 years, when the second 25-year plant would provide service beyond that of the 40-year asset. And so forth.

An alternative is to extend the analysis period to a length of time that results in the "least common denominator" analysis period. One could illustrate this point with an extreme example. It would take a 200-year analysis to make an equivalent comparison between the 25-year asset and a 40-year asset. The "least common denominator" analysis period would result in eight 25-year assets and five 40-year assets so that the analysis ended with the end-life of both assets. Figure L-18 shows a full 200 years of nominal resource costs for a series of 40-year and 25-year assets using rate-base cost recovery and assuming no real, but 2.5 percent nominal inflation. In this example, the Present Value of Resource costs (PVRR) of both assets is exactly the same. Therefore, if all else were equal in this example, one would be indifferent over this 200-year analysis period between owning a series of 25-year resources or owning a series of 40-year resources.

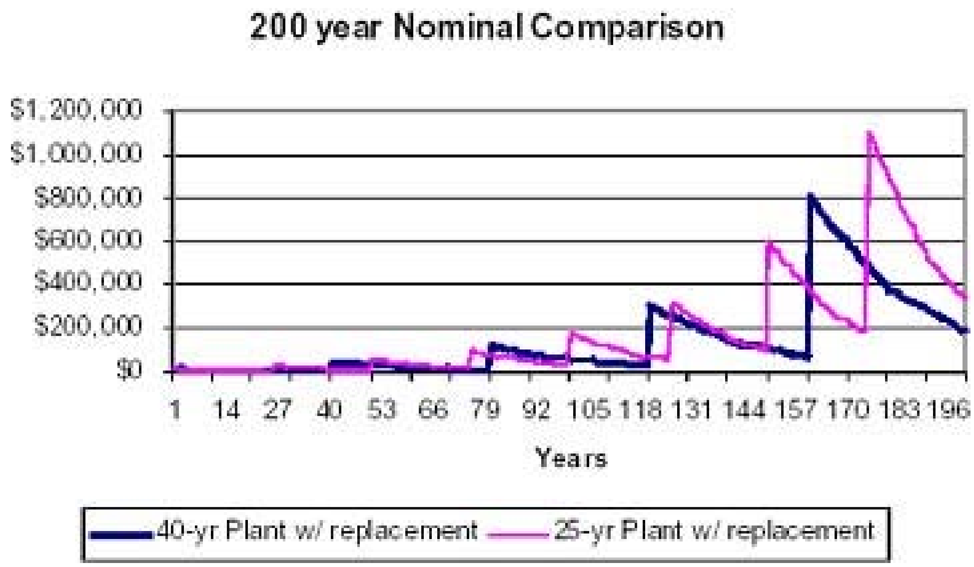



**Figure L-18: 200 Year Comparison**

Compiling a 200-year analysis is not practical. Even if it were, another common situation, new plants with *equal lives* staggered over the planning period, does not admit the "least common denominator" approach. There is no "least common denominator" of lifetimes in that case. The cash flows illustrated in Figure L-18 do illustrate a point, however. If one is indifferent between assets when considering an "equivalent" analysis period, then what are the results one gets when looking at a more practical analysis period, say 20 years.

Figure L-19 shows the cumulative PVRR of the above resource costs used in Figure L-18. (Cumulative PVRR is derived by taking the present value of each year's resource cost and adding it to the sum of the previous years' present value of resource cost; all discounted at 7.5% in this private utility example to a common time.) Figure L-19 shows only the results of the first 45 years in order to highlight the earlier years. Over an extended analysis period (200 years), the PVRR of both assets is the same.

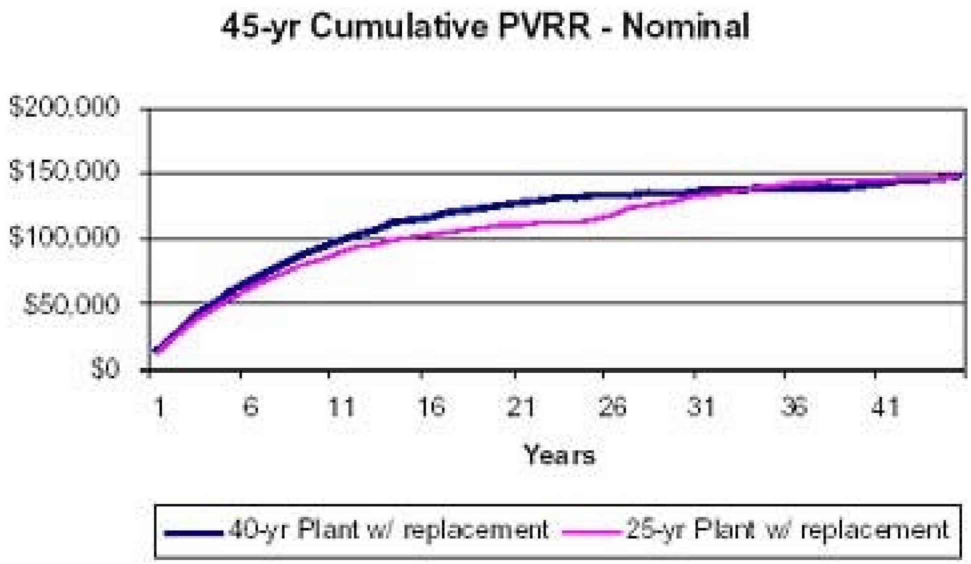



**Figure L-19: 45-Year Cumulative PVRR**

Figure L-19 clearly illustrates the problem with using DCF costs for comparing resources with different lifetimes. By definition, these assets were valued such that one should be indifferent. However, as can be seen, depending on the length of the analysis period, the nominal resource cost has created a valuation gap between the 40-year asset and the 25-year asset's resource cost. This could lead to misleading conclusions regarding the comparative cost of one resource versus another. DCF costs, without some kind of end-effects adjustment, could result in incorrect analysis findings.

End-effect adjustment calculations can be challenging as well. For example, within a 20-year analysis period, what is the proper adjustment to a 40-year asset and a 25-year asset's cost that will place the analysis on equal footing? There are mathematical formulas for the PVRR of capital projects over an infinite time horizon -- as would be necessary when no "least common denominator" of lives exist. Computing revenue requirements for capital, however, is the least of the problem. It is more difficult to estimate operating costs and benefits of generation, because no simple, regular pattern exists. In particular, there is at least some seasonal variation in such costs and benefits, but what about price spikes, excursions from equilibrium prices, in the last year? What about the effect of annual variation in stream flows and hydrogeneration? These questions apply to all resources, including market purchases and contracts. The answers are as varied as are methodologies to calculate the end-effect adjustment. However, an easier approach allows for comparative analysis between resource options. It provides more representative study results using a practical study period. It consists of using real levelized resource cost.

Real Levelized Resource Cost

Real levelized resource cost is a methodology for converting the year-by-year cash flows into a sequence of fixed constant dollar payments, much like certain kinds of annuities, that has the same present value as the year-by-year cash flows. This approach also easily accommodates both real and nominal cost inflation.

For DCF, the replacement unit causes resource cost to take a huge jump. For real levelized costs, the unit replacement cost continues at the same rate (assuming no real inflation in construction cost). An explanation of how real levelized resource costs are calculated appears in a later section. Figure L-20shows the real levelized resource cost for the same two assets that were shown in Figure L-18, which have no real inflation in construction costs but do have nominal inflation.

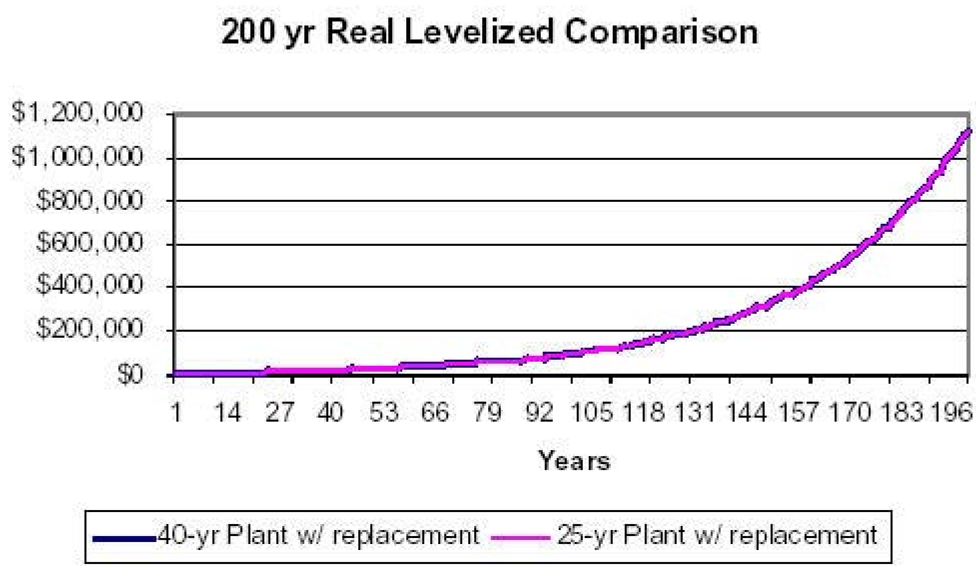



**Figure L-20: Comparison (J.6)**

Because Figure L-20 uses the same assets as Figure L-18, the PVRR of the resource costs are the same for both assets; hence the real levelized resource cost values for each resource are the same each year. As mentioned earlier, the replacement of the resources throughout time does not create huge jumps in resource costs. Figure L-21 is the same representation as Figure L-19, except that here again, the results are presented using real levelized resource costs. One can see that it does not matter how long the analysis period is, the comparative resource cost valuation is the same at any point in time.

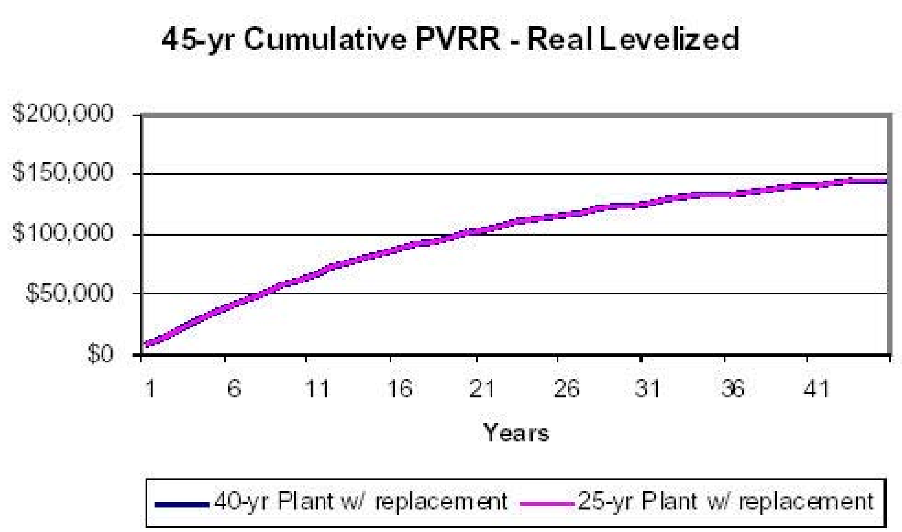



**Figure L-21: J-7**

So far, the two resources shown have been placed in service on the same date and have been priced to come to the same PVRR over an "equivalent" extended analysis period. This has been solely for the purpose of creating a case that shows that assets of equivalent cost should reflect that equivalent cost, regardless of how long the analysis period is. Real levelized resource costs provide such a case. The advantage of using real levelized resource costs is also extended to an analysis that compares various resources with various lives and various in-service dates. Real levelized resource costs will capture the comparative economic costs with respect to one set of resources being compared against another, without the need for end-effects adjustments.

Economic Decision-Making with Real Levelized Costs

Using real levelized costs for capital investments is more than a practical solution to this resource comparison problem. In accounting, there is a fundamental concept, the "matching principle," that stipulates that the costs for an asset should match the benefits the asset provides. The matching principle underlies a host of commonly accepted accounting practices that have their basis in economics, such as depreciation and rate-base recovery. If costs were not allocated over the useful life of an asset, it could be argued that economic efficiency would not be served. For example, if ratepayers had to pay for electricity in one year enough to recover the entire expense of a power plant, the resulting high price would significantly and inappropriately discourage electricity use. Moreover, costs for the plant would shift to a small group of ratepayers who could not afford to curtail use. In subsequent years, ratepayers would tend to over-use electricity, because they would not see the cost of that plant, despite the fact that they benefit from the plant's availability. Rates that do not match costs to benefits therefore send improper price signals to consumers. Using real levelized costs better reflects how costs apply in this economic, "matching" sense.

A conspicuous example of where some utilities engage in mismatched pricing is conservation. In particular, these utilities expense their investment cost of conservation programs, much like paying the full cost of a power plant in a single year. The reason often given for this practice is the difficulty of providing collateral for financing, which would levelize the conservation cost. That is, if the utility defaulted on its loans, it would be impractical and pointless for investors to remove conservation from utility customers' homes and businesses for resale. This is not the case with a power plant, which investors can sell to recover from default. Without this financing, however, either the ratepayer pays all conservation costs up front or the utility effectively makes an unsecured loan to the ratepayer. The first alternative creates uneconomic price signals. The second alternative requires the utility to burden its own balance sheet and hope for fair regulatory treatment in the future. Neither of these alternatives is attractive. The Council's solution to this situation is the Plan's Action Item **CNSV-11**, which calls for state-guaranteed utility (or non-utility) financing, assured through the state's taxing authority.

To prepare the RL costs for the portfolio model, life-cycle fixed plant costs, including construction and interest during construction, are discounted using the rate appropriate for the financing and accounting. For example, the Generation Resource Advisory Committee (GRAC) made determinations about which types of agencies would most likely build wind plants, coal plants, and so forth. Often, the GRAC arrived at a participation-weighted balance of financing, using a blend of private IOU, federal, and public investment. The present value calculation uses the blended discount rate. To levelize the present value the Council should have used its four percent discount rate. However, due to an oversight, the costs in the regional model runs were levelized at the blended after-tax cost of capital (4.9%) [**2**]. Finally, the portfolio model uses four percent to discount the real levelized quantities, adjusted for real cost escalation, over the study period. The section "Present Value Calculation," below, describes the formulas in the portfolio model that perform this task.

Comparison to Market Purchases

As explained in the previous section, the portfolio model uses valuation in the market for estimating variable system costs and benefits. The year-by-year capital resource cost in Figure L-17 shows the front-end loaded resource cost for capital investment typical of a private utility. How does this cost compare with the alternative of market purchases? Any analysis period short of a full asset life-cycle analysis will overstate the capital resource costs in the early years, while leaving the lower cost later years out of the analysis. With a 20-year analysis period, using cash flows for resource capital will overstate the comparative cost of long-lived resources. Restating the issue a different way, consider two groups of customers in a rising market price environment. Customer Group A will get to use and pay for a 40-year resource during the analysis period, say, the first 15 years, and Customer Group B will get to use and pay for the resource during the remaining plant life, or 25 years. Without some kind of adjustment, simple DCF resource costs would cause Group A to pay all the higher cost years, when market price is lower, while Group B would get to pay for all the lower cost years when market price is higher. This is hardly a fair allocation of resource costs among Customer Groups A and B when comparing the resource cost to market purchases.

Shortcomings and Disadvantages

Absent 20/20 foresight, any analysis methodology will have its challenges, and real levelized costs are no exception. Implicit in the use of this technique is the assumption that the future, beyond the horizon of the study, either does not make much difference to today's economic decision or will be economically similar to the study period. The former is true when the discount rate is large and the impact of cash flows beyond study period is negligible. The four percent discount rate used by the Council is probably toward the lower end of rates for which that argument might apply.

The latter assumption may hold in many circumstances, but there are situations where we expect it would not. For example, a carbon penalty imposed late in the study period would probably extent well beyond the study horizon. Such a carbon tax would have a disproportionate impact on coal plants. A coal plant built several years before the carbon tax arises may see economically productive years before the tax and harder times after the tax. Because the carbon tax is a variable cost of operation, and not included in the real levelized capital cost, the study would only see the balance of these, weighed by their relative term within the study and not the less attractive economics after the study.

There are several possible accommodations for this shortcoming. One is the consideration of some end effects, perhaps using the last year of analysis. This section has already discussed the associated difficulties with this approach. Nevertheless, in subsequent studies such adjustments might make reasonable sensitivities. Another accommodation, which the Council uses instead, is simply to ask whether the recommended plan would have changed if a carbon tax had more severely penalized coal-fired and, to a lesser extent, gas-fired generation. The Council concluded it would not. The plan prepares the region for significant amounts of conservation and wind generation. The amount of early coal is small, a single 400 MW unit. The timing and amount of this early coal permits re-evaluation before licensing and siting begins. By then, additional information about the likelihood of carbon penalties will be available. Gas-fired generation does not appear until late in the study period. The arguments regarding licensing and siting pertain to an even greater degree. For the Action Plan period, the plan merely calls for securing siting and licensing options for these fossil fuel-fired plants.

In summary, the portfolio model covers a 20-year forecast period. During this forecast period, the model is comparing the alternative resources available to determine the risk-constrained, least-cost plan. Because many of the potential resources have economic lives which extend beyond the analysis period and have lives of various lengths, appropriate methods are necessary to capture the comparative costs of such capital-intensive investments. Alternative financing and accounting methods can also distort the economic evaluation of such resources. An end-effects adjustment is feasible, but the value of those end-effects can be difficult to determine. An alternative approach, which the portfolio model uses, is real levelized capital resource cost. Real levelized cost eliminates the need for an end-effects adjustment, and provides a reasonable approach for comparing the cost of capital resources against each other and also against market purchase resources. Real levelized resource costs may not fit all analysis situations. Care must be taken when events near the end of the study, such as the emergence of a carbon penalty, create situations that extend beyond the study period and may render study results non-representative. Nevertheless, when used with care, real levelized capital costs can do a better job of reflecting the true economic costs of capital resources than simple DCF methods.

This concludes the preamble to single-period calculations. As explained in the previous section, Appendix P provides extensive discussions of how the model computes values for loads, natural gas, and other aspects of a future. Prior periods' electricity prices or other factors can then modify these in the Twilight Zone illustrated in Figure L-6. If there are any such modifications, the discussion is in the section "Multiple Periods," which follows below. The remaining portion of this section on single-period calculation picks up the calculation after any modification in the Twilight Zone.

## Loads

Appendix P describes the construction of quarterly energy requirements before any adjustments due to the choice of plan. The plan *does* affect loads, however, as the amount of capacity available affects the price for wholesale electricity, and wholesale electricity prices have a long-term effect on loads because of price elasticity. See page L-59 in the section "Multiple Periods" for this treatment.

The **energy calculation** in {AQ322} is simply the product of the elasticity effect {AQ321}, the on-peak portion of load in MWa {AQ183}, and the number of hours on-peak in a standard quarter.



One of the conventions the model design tries to adhere to is to avoiding putting data into code or formulas. Admittedly, this version of the regional portfolio model is not always successful in achieving that objective. Nevertheless, some kinds of numbers arguably could appear in formulas. For example, the number of days in a week and the number of months in a year will not change, so burying them in code presents little risk to some future user who might want to make changes to the model. Because the design of the regional portfolio model permits only one particular definition of the period, namely the standard quarter, the number of on-peak hours in a standard quarter is a fixed constant and therefore would be an exception to this rule.

Calculating the **cost of meeting that load** in {AQ323} uses the valuation approach. Specifically, the cost is the average energy {AQ322} times the average on-peak period market price {AQ204} times a special factor that incorporates the correlation of loads and market prices. The cost is divided by $10^6$ to restate the dollars in millions of 2004 dollars.

The special factor is (1+$S$14*$O$322), where $S$14 is the correlation between non-DSI loads and power prices and $O$322 is a fixed constant. The fixed constant is calculated in cell $O$322 from the formula

SQRT(EXP($R$184^2+$R$201^2)-EXP(R184^2)-EXP(R201^2)+1)

The value in \$R\$184 is the on-peak intra-period load variation; the value \$R\$201 is the on-peak intra-period electricity price variation. The complexity of this equation stems from the fact that the definitions of the load and price variations are slightly different from a simple standard deviation of load or price.

Appendix P lays out the justification for use of lognormal distributions for load and price. The variations that appear in \$R\$184 and \$R\$201 are the standard deviations of the log-transformed loads and prices. There is, however, a well-known relationship between the mean and standard deviation of the transformed and non-transformed variables.[13] If ***E(p)*** and $\boldsymbol{\sigma_p}$ denote the expected price and standard deviation after log transformation and ***E(P)*** and $\boldsymbol{\sigma_P}$ before transformation, and similarly and ***E(q)***, $\boldsymbol{\sigma_q}$, ***E(Q)*** and $\boldsymbol{\sigma_Q}$ for quantity, the relationship for standard deviations is

$$\sigma_Q = E(Q)(e^{\sigma_q{}^2} - 1)^{1/2}$$

$$\sigma_P = E(P)(e^{\sigma_p{}^2} - 1)^{1/2}$$

The correlation used in this calculation is a ranked correlation, so the correlation is unaffected by transformation. From equation (1) above, the expected revenue is

$$\begin{aligned} E(PQ) &= E(P)E(Q) + \sigma_P \sigma_Q \rho_{PQ} \\ &= E(P)E(Q) + E(P)(e^{\sigma_p{}^2} - 1)^{1/2} \sigma_Q E(Q)(e^{\sigma_q{}^2} - 1)^{1/2} \rho_{pq} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p{}^2} - 1)^{1/2}(e^{\sigma_q{}^2} - 1)^{1/2} \rho_{pq}\right\} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p{}^2 + \sigma_q{}^2} - e^{\sigma_p{}^2} - e^{\sigma_q{}^2} + 1)^{1/2} \rho_{pq}\right\} \end{aligned}$$

This is the formula in cell {AQ323}.

The on-peak non-DSI costs present-valued in {CV323}. The formula is described on page L-79, in the section, "Present Value Calculation."

DSI interruptions can be of a short-term nature, such as hourly or daily curtailments, or they can be long-term. Long-term interruptions involve smelter shutdowns and startups. The portfolio model assumes that demand response, discussed below, captures short-term interruptions. Energy and cost calculations for long-term price induced interruptions of DSI on-peak load are in the range {AQ327:AQ329}. Indeed, the name of this behavior is Long Term Price Responsive Demand or LTPRD, and the acronym appears several places in the worksheet. The capacity in {AQ327} depends on smelters shutting down and restarting, behavior that requires understanding of choices made over several periods. Description of modeling DSI capacity therefore is in its own section on page L-60.

The **energy calculation** for DSIs is in {AQ328}. The formula is the product of the DSI total capacity and the number of on-peak hours in a standard quarter.

[13] See Hull, John C., ***Options, Futures, and Other Derivatives***, 3rd Ed., copyright 1997, Prentice-Hall, Upper Saddle River, NJ., ISBN 0-13-186479-3, page 230

Calculating the **cost of meeting that load** in {AQ329} uses the valuation approach. The long-term capacity is uncorrelated with short-term electricity price variation, so the cost is simply the product of the energy and the average on-peak price. It is divided by $10^6$ to restate the dollars in millions of 2004 dollars. The costs are present valued in {CV329}.

Off-peak calculations begin in the second half of the worksheet {row 684}. The calculations for off-peak non-DSI loads and costs are in {AQ687:AQ688} and the DSI loads and costs are in {AQ692:AQ693}. These calculations are identical to those for on peak, except in obvious ways. The formulas use the number of off-peak hours in a standard quarter (864) and off-peak electricity prices. The off-peak long-term demand for DSI loads is the same as on-peak demand.

## Thermal Generation

The model estimates hourly generation dispatch and value. Moving down from the load calculations, the first of these appears in range {AQ339:AQ340}, associated with PNW West NG 5_006. (A description of this gas-fired resource and of the modeling values that this resource uses appears in the section "Existing Resources" on page L-92, below.) The value in AQ339 is the energy in MWh and AQ340 is the cost in millions of 2004 dollars. A single call to a user-defined Excel function (UDF) returns these values as a vector of two single precision real numbers.

This section begins with an explanation of how the regional portfolio model estimates thermal dispatch and value, assuming fixed fuel price. It then generalizes this approach to the case where both electricity price and fuel price are possibly correlated stochastic variables. Finally, it documents the Excel user-defined function that implements the logic. It also points out the analogies between these calculations and financial, European call options and exchange-of-assets options.

Thermal resources dispatch whenever the market price of electricity exceeds their short-run marginal cost. The short-run marginal cost includes cost for fuel and variable operations and maintenance (O&M). For example, assume a gas turbine with a capacity of 1.0 MW has a short-run marginal cost of $30/MWh. For the sake of this illustration, the O&M cost is zero and all the short-run cost is fuel cost. The turbine faces a market price that varies regularly over some period, say a month with 672 hours. When the market price is greater than the fuel price, the turbine dispatches, as illustrated by the red area in Figure L-22.

In each hour, the value of this generation is the difference between what the generation earns in the

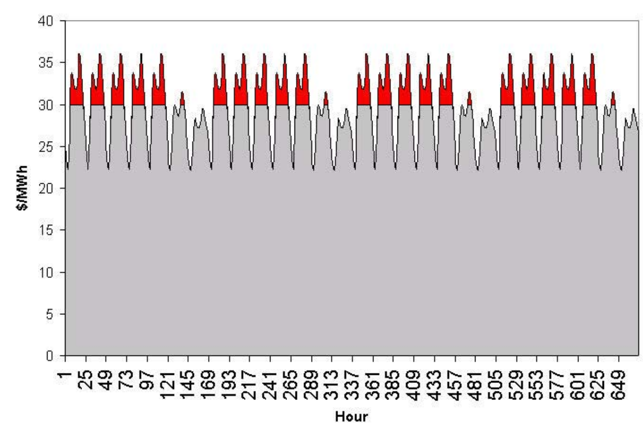



**Figure L-22: Thermal Dispatch**

market, the market price, and what it costs to generate the power, the short-run marginal cost. The value of the turbine over the month is the sum of the hourly values.

To make the valuation more quantitative, first note that the hourly value is ***C max(0, $p_e$(h)-$p_g$(h))***, where ***C*** is the capacity of the turbine, ***$p_e$(h)*** is the price of electricity and ***$p_g$(h)*** is the price of gas denominated in $/MWh, i.e., the short-run marginal cost of the turbine. This is just the height of the red area in Figure L-22 in each hour. Note that it is never negative, because the turbine does not dispatch unless it can add value. Summing up the value across hours is just

$$V = \sum_{h \in H} C \cdot \max(0, (p_e(h) - p_g(h)))$$

where

$H$ is the set of hours (672 in this case)

$p_e(h)$ is the price of electricity in this hour ($/MWh)

$p_g(h)$ is the price of gas in this hour,

assuming a fixed heat rate ($/MWh)

$C$ is the capacity of the turbine (1 MW in our case)

Restating the total value in terms of the mean or average value over the period, and interpreting this as the expected mean of a sample drawn from the population of values, the total value is

$$V = C \sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)$$

$$= CN_H \frac{\sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)}{N_H}$$

or

$$V = CN_H E\left[\max\left(0, p_e(h) - p_g(h)\right)\right] \qquad (3)$$

where ***E*** is the expectation operator and ***$N_H$*** is the number of hours in the period (672 in this case).

The expectation in this formula is (See reference [**3**]):

$$c = \overline{p}_e N(d_1) - p_g N(d_2) \qquad (4)$$

where

$N$ is the CDF for a $N(0,1)$ random variable

$\overline{p}_e$ is the average electricity price

$p_g$ is the gas price

$\sigma_e$ is standard deviation of $\ln(p_e(h))$

$$d_1 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} + \sigma_e / 2$$

$$d_2 = d_1 - \sigma_e$$

The turbine is therefore $\boldsymbol{V = CN_H c}$. Those familiar with financial derivatives theory will recognize the similarity of this equation to that of a European call option[14].

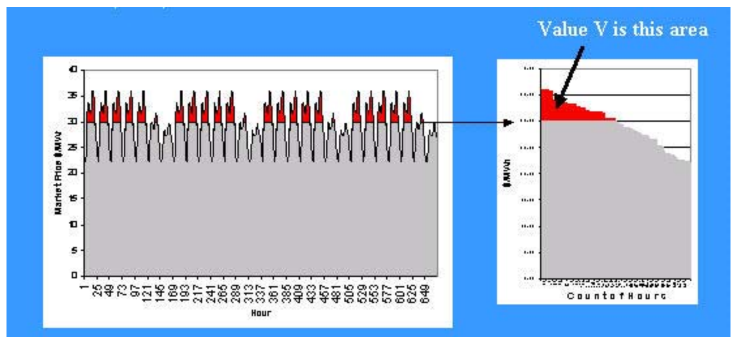



**Figure L-23: Sorting by Market Price**

If we sort the hours illustrated in Figure L-22 by the market price, we obtain the market price duration curve in Figure L-23. This aggregation creates a simple area under the market price curve that corresponds to the value of the turbine. Flipping this duration curve over as in Figure L-24 creates a cumulative distribution function (CDF). The value of the CDF is the likelihood that electricity prices will exceed the values on the horizontal axis, if one drew an hour at random from the month. The red area to the left of the short-run marginal cost of $30/MWh is the expected value of turbine dispatch.[15]

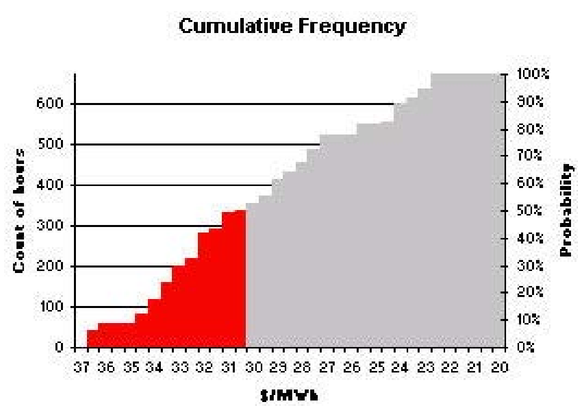



**Figure L-24: Cumulative Probability Function**

[14] See for example, Hull, op. cit., page 241. Set r = 0, T = 1, X = $p_g$, $\sigma_s = \sigma_e$, and S equal to the average of the hourly electricity prices $p_e(h)$. This is the version of the equation for a stock that pays no dividends.

[15] This is completely analogous, however, with the valuation of an option. For an option, the value derives from the expected stock price above the strike price, given the likelihood distribution of prices at expiration. Whereas the volatility (standard deviation) of stock prices describes the width of the corresponding probability density function, here it describes the width of the probability density function for electricity prices during the month.

Although estimating the value of the turbine in the electricity market is essential for calculating system costs, **estimating the energy generation** of the turbine is equally important. At a minimum, we need to know its energy generation to determine whether the total system is in balance with respect to energy. That is, we need to know whether the electricity prices the model is using are generating more energy than system requirement plus exports. If so, prices are too high. Similarly, if the prices are inducing the generation of too little energy to meet requirements, given imports, the prices are too low.

To estimate generation, note that the CDF for generation already specifies the capacity factor for the turbine, as illustrated in Figure L-25. The energy will correspond closely to the hours of generation because for those hours when prices make generation economic, the optimal loading is loading to the lowest average heat rate, which is the plant's assumed maximal loading. The generation would therefore be the capacity of the turbine times the number of hours in the period, times the capacity factor. The function that computes the value of the power plant unfortunately cannot make use of this graphical representation for capacity factor and must resort to more algebraic devices. There is, however, an algebraic relationship between the value of an option (or turbine) and the dispatch factor.

The CDF is a function of $\boldsymbol{p_e}$, and the expectation $\boldsymbol{E(0,p_e(h)-p_g(h))}$ is the integral of the CDF($\boldsymbol{p_e}$) for $\boldsymbol{p_e}$ from infinity down to $\boldsymbol{p_g}$. Moreover, the capacity factor is just CDF($\boldsymbol{p_g}$). These relationships are evident from Figure L-25. Algebraically, the capacity factor ***cf*** is derived as follows:

$$V = C \cdot N_H \int_{\infty}^{P_g} \mathrm{CDF}(p_e)\, dp_e$$

$\Rightarrow$ (Fund Thm of Calculus)

$$\left.\frac{\partial V}{\partial p_g}\right|_{p_g=p_g^*} = -C \cdot N_H \cdot \mathrm{CDF}(p_g^*)$$

$\Rightarrow$

$$\mathrm{cf} = \mathrm{CDF}(p_g^*) = -\frac{1}{C \cdot N_H} \left.\frac{\partial V}{\partial p_g}\right|_{p_g=p_g^*}$$

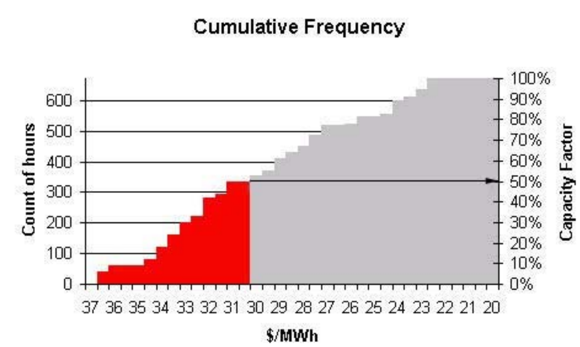



**Figure L-25: Capacity Factor**

To find the value of the partial derivative in the last equation, use the fact that $\boldsymbol{V=CN_Hc}$ and take the derivative of equation (4) with respect to the strike price [**4**].

$$\frac{\partial c}{\partial p_g} = -N(d_2)$$

where

$$d_2 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} - \sigma_e / 2$$

This gives us an explicit formula for the capacity factor, and hence energy, as a function of the gas and electricity price.

$$\mathrm{cf}(p_g, \overline{p}_e) = N(d_2)$$
$$d_2 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} - \frac{\sigma_e}{2}$$

Those who are familiar with option theory recognize that ***$N(d_2)$*** is the probability that the strike price is paid for an option, that is, the probability that the option is "in the money" upon expiration. This is consistent with the earlier observation (footnote 15) that capacity factor is the likelihood that electricity prices will exceed the short-run marginal cost of $30/MWh, if one drew an hour at random from the month.

Up to now, we have assumed that the gas price is fixed. The problem with that assumption, of course, is that gas prices do change and may correlate with electricity prices. The value of generation is still given by equation (3), but now both ***$p_e(h)$*** and ***$p_g(h)$*** are stochastic variables. Doing this directly introduces some computational problems[16], but by taking a slight rearrangement of equation (3), we obtain

$$V = E\left[ S_2 \max\left( 0, \frac{S_1}{S_2} - 1 \right) \right]$$
$$S_2 = CN_H p_g(h)$$
$$S_2 = CN_H p_e(h)$$

If we assume lognormal distribution for both electricity and gas prices, the preceding equation may be evaluated explicitly:

[16] One approach to solving this issue is to use a "spread option." The value of a spread option derives from the difference in price between two commodities, in our case electricity and natural gas (assuming some conversion efficiency). The problem with a general spread option, however, is that when the strike price is near the expected commodity price, the equations above do not work, so a more sophisticated approach is necessary, which involves solving some integral equations. Finding the solutions to the integral equations, unfortunately, is slow and somewhat unstable. Moreover, the spread option is unnecessarily general because, for the turbine, value derives from differences in only one "direction," that is, when electricity prices are strictly higher than gas prices.

$$
\begin{aligned}
&V = \varepsilon = S_1 N(d_1) - S_2 N(d_2) \\
&cf(\overline{p}_g, \overline{p}_e) = N(d_2) \\
&d_1 = \frac{\ln(S_1 / S_2)}{\sigma} + \sigma / 2 \\
&d_2 = d_1 - \sigma \\
&\sigma = \sqrt{\sigma_{S_1}{}^2 + \sigma_{S_2}{}^2 - 2\rho\sigma_{S_1}\sigma_{S_2}} \\
&\text{where} \\
&S_1 = \mathrm{CN_H}(\overline{p}_e - p_{VOM})(1 - FOR) \\
&S_2 = \mathrm{CN_H}(\overline{p}_g + p_{CO_2})(1 - FOR) \\
&p_{VOM} \text{ is the variable O \& M rate (\$/MWh)} \\
&p_{CO_2} \text{ is the carbon tax penalty (\$/MWh)} \\
&\sigma_{S_1} \text{ is standard deviation for } \ln(\mathrm{S}_{1,t} / S_{1,t-1}) \approx \ln(p_{e,t} / p_{e,t-1}) \\
&\sigma_{S_2} \text{ is standard deviation for } \ln(\mathrm{S}_{2,t} / S_{2,t-1}) \approx \ln(p_{g,t} / p_{g,t-1}) \\
&\rho \quad \text{is the correlation in values between } S_1 \text{ and } S_2 \\
&FOR \text{ is the unit's forced outage rate } (0 \le FOR \le 1.0)
\end{aligned}
$$

where, as before, we have adjusted the price of gas ($/MMBTU) and the price of the $CO_2$ tax ($/MMBTU) to $/MWh using the assumed heat rate (BTU/kWh) of the unit. Also, this formula introduces the forced outage rate (FOR) for the unit, which limits the amount of energy that the unit can produce.[17] Note that the variables S1 and S2 here are total values, not prices. This means that, whereas in the case of deterministic $\boldsymbol{p_g(h)}$, the value V = CNHc used the quantity CNH times the unit value c, we now have V = ε.

The portfolio model performs this calculation through an Excel UDF. The range {AQ339:AQ340}, associated with PNW West NG 5_006, contains a vector-valued function. This function returns two single-precision real numbers, one for the energy and one for the value in millions of 2004 dollars. The call in {AQ339:AQ340} is

```
=SpreadOption( $P339, AQ$46,AQ$204-$R$337,AQ$68+0.059*AQ$74,(1-AQ336)*1152*$S$335,(1-AQ336)*1152*$S$335*9.2,1,0,0,0,$R$201,$R$55,$T$14)
```

The function's declaration[18] for the parameters is

[17] Those familiar with financial derivative theory will recognize the similarity to the value for an exchange option that pays no dividends (See, for example, Hull, op. cit., page 468, and note that S1 and S2 are reversed here from the notation Hull uses.) Using the convention T = 1, S1 for the average of the hourly values for electricity generation, and S2 for the average of the hourly values of gas that we must hold to produce the generation.

[18] Although the function's name is "SpreadOption," examination of the code will reveal that it is really the exchange option described above.

```
Function SpreadOption(ByVal lPlant As Long, ByVal lPeriod As Long, _
   ByVal dblSp1 As Double, ByVal dblSp2 As Double, _
   ByVal dblQuan1 As Double, ByVal dblQuan2 As Double, _
   ByVal dblTime As Double, ByVal dblIntRate As Double, _
   ByVal dblYeild1 As Double, ByVal dblYeild2 As Double, _
   ByVal dblVol1 As Double, ByVal dblVol2 As Double, ByVal dblCorr As Double) _
      As Variant
```

The parameters are as follows

| | |
|---|---|
| lPlant As Long | a zero-based index of plant, on- and off-peak plants modeled separately |
| lPeriod As Long | a one-based index of period |
| dblSp1 As Double | price ($/MWh) for electricity, less VOM |
| dblSp2 As Double | price ($/MMBTU) for fuel, including CO2 tax |
| dblQuan1 As Double | MWh of electricity |
| dblQuan2 As Double | MMBTU of fuel |
| dblTime As Double | time to expiration (years) = 1 for plant dispatch purposes |
| dblIntRate As Double | annual interest rate for yields (not used) |
| dblYeild1 As Double | yield on commodity 1 (electricity, not used) |
| dblYeild2 As Double | yield on commodity 2 (natural gas, not used) |
| dblVol1 As Double | variation in electricity price within the period |
| dblVol2 As Double | variation in fuel price within the period |
| dblCorr As Double | correlation between electricity price and fuel price |

The only parameter inputs that should require description beyond what the section already has provided are the following. The parameter dblSp2 uses converted cost of a tax in $/U.S. short ton of $CO_2$. The conversion to $/MMBTU is

$$\$/MMBTU = \frac{\$}{ton}\frac{ton}{lb}\frac{lb}{MMBTU}$$

where tons per lb is 1/2000, methane combustion produces 117 pounds of $CO_2$ per MMBTU, and carbon produces 212 pounds of $CO_2$ per MMBTU. For a gas-fired turbine, the conversion to dollars per million BTU from dollars per ton is 0.059, which appears in the example of the function call, above. The quantities dblQuan1 and dblQuan2 in the function call, above, also use 1152, the on-peak hours per standard hydro quarter. Finally, the value for the dblQuan2 parameter uses 9.2 kBTU/kWh, which is the assumed heat rate for this particular unit.

## Contracts

For the purposes of the portfolio model, contracts are risk-management agreements that make future price and delivery of energy more certain. The regional model does not address contracts between parties within the region, because the region as a whole is indifferent to such arrangements. Consequently, only contracts between the region and counterparties outside of the region are material.

The regional model assumes most existing contracts are fixed-price, forward contacts for specific quantities of energy. Such contracts are agreements to pay a fixed sum for energy upon delivery. New contracts were not included among new resource candidates for reasons explained later in this section.

There are two aspects of contracts that impact regional risk: power flows and economic flows. Power flows potentially influence market price and dispatch; money flows impact economic predictability. The next two sections discuss these distinct aspects of contracts.

**Power Flow**

To understand how existing, firm contracts for energy sales out of the region affect power flow, market price, and dispatch, we consider a simplified example. In this example, only contracts with California exist. There are three cases to consider: uncongested transmission between the region and California, congested transmission with power flows headed north from outside the region into the region, and congested transmission with power flows headed south.

If transmission is not congested, market price in the region are substantially the same as that outside the region and it makes little difference whether or not the firm contracts exist. Wholesale market prices in the region would be the same with and without these firm contracts. The single market price would determine dispatch of plants both in and outside the region.

If transmission flow is congested in the northern direction, this means that market prices in the region are higher than market prices south of the region. In this case, and generators would be better off selling power into the higher-priced regional market and meeting their commitment to the southern counterparty with market purchases from the southern market. The counterparty, of course, would be indifferent to this arrangement, because the parties would have previously agreed upon price.

If transmission is congested southbound, market prices in the region are lower than market prices south of the region. Assume a regional generator is dispatching out of economic order, given regional load plus export limit, to meet contract requirements. First, consider the situation where the generator is dispatching when its cost is above regional market price. This makes no sense because the generator could buy in the regional market, shut down his plant, and make a profit by making the contract obligation with the market purchase. Second, consider the situation where the generator is not dispatching when its cost is below regional market price. The generator must meet its obligation to the contract, which leaves it two options. It could buy from the regional market, but that is more costly than dispatching. Alternatively, it could buy out of the southern market to meet the obligation, but that is even more costly. In this situation, the plant again dispatches at the regional market price. Certainly, the distribution of profits in this case depends on which generators have transmission rights, but the dispatch order of plants and consequently the market prices are unaffected by the contract.

What this discussion shows is that contracts do not affect power plant dispatch decisions or market prices, either within or outside the region. The dispatch and regional market price are unaffected by contracts, irrespective of who owns the generation projects or whether the regional load or an independent power producer (IPP) gets the value of the generation. Although the example is for an export contract, some thought will convince the reader that it applies to an import contract, as well. The ability to counter schedule contracts assures that the fundamental economics of power plants will determine their dispatch and the resulting market prices.

Modeling counter scheduling opportunities is important to the regional model and shows up explicitly in calculations. To illustrate the calculation, consider the region as a tank with a single pipe for importing and exporting energy as illustrated in Figure L-26. We can think of the transmission capability of the this simple system as the symmetric flow capability of the pipe, 5000 MW in both directions in this example.

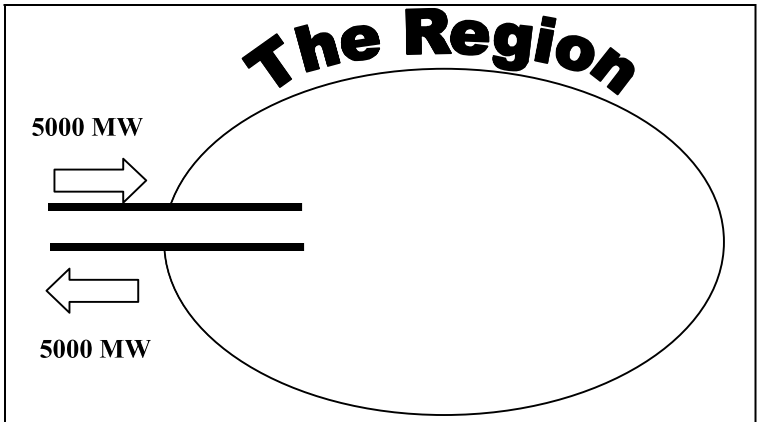



**Figure L-26: Transmission Before Contracts**

Now, we consider the situation where the model represents an energy import contract as a resource in the region. If we have 3000 MW of additional energy available to region by virtue of the import, there is an implied flow of energy over the transmission system into the region of 3000 MW. This, in turn, means we have only 2000 MW of net transmission capability left for remaining contracts or spot purchases from outside the region. By the same token, the import can be counter scheduled, which adds 3000 MW for remaining export contracts or spot sales to outside the region. Consequently, the net import and export capability of the region must be adjusted to reflect any firm contracts into or out of the region, as shown in Figure L-27.

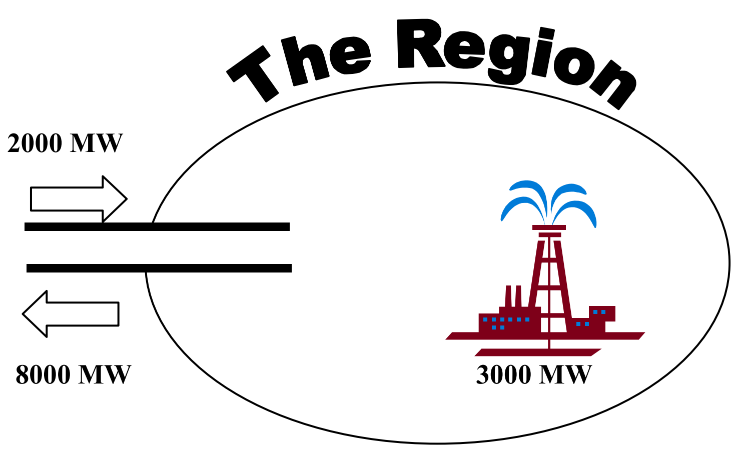



**Figure L-27: Transmission After Contracts**

In the workbook, the on- and off-peak average energies (MWa) appear initially in {rows 84 and 88} respectively. The data values are presented and documented below, in the subsection "Contracts" of the section "Resource Implementation and Data." These MWa values are used by the calculation of annual energy for the decision criteria in {row 290} (see e.g., {AT290}), for a estimate of Non-Hydro Capacity ({row 670}) used by certain reports (see the section "Portfolio Model Reports And Utilities"), and in the contribution to regional energy balance. For the regional energy balance calculation, the worksheet first converts MWa to MWh using the number of standard hours in the subperiod ({rows 367 and 731}). The value calculation {AQ368} uses MWh equivalent and the relevant market price to determine cost or value of the contract. For reasons described in the next section, the worksheet computes only the gross value, assuming the costs for these fixed contracts effectively are sunk. The energy requirements calculation { AQ676 and AQ1032} uses the MWh equivalent to determine the necessary purchases on the market. The adjustment to import and export capability, illustrated in Figure L-27 is reflected in calculations at { AQ677 and AQ1033}.

**Money Flows**

Contracts reduce risk to the parties by assuring financial certainty. Irrespective of factors that may influence the dispatch of resources, some party is responsible for delivering power to a particular substation at an agreed-upon price.

The portfolio model captures economic consequences of resource decisions to an unprecedented extent, but there are still limitations to what we have modeled. One of the practical constraints is our limited knowledge of the financial terms of existing and new contracts. The portfolio model incorporates energy flow associated with existing long-term contracts, but unfortunately the Council has no basis for estimating contract costs. It is assumed that existing contracts have fixed-price and fixed-energy terms, and the costs of the contracts are therefore sunk. The gross value of these contracts, however, is valued in the market. Thus, we capture the cost of meeting future requirements and value contract deliveries to the region. Because the energy is constant over each subperiod, the correlation with market price is zero and the calculation of the gross value is simply the product of average market price and energy, as shown in {AQ368}. All dollar amounts are in millions, so the formula divides the product by 1,000,000.

Although a single utility's risk model would do so, the regional model does not examine ***future*** contracts the region might enter into either with IPPs or with entities outside of the region. Although such contracts would certainly affect the economic risk situation for the region and for parties within the region, the regional model avoids modeling these contracts for several reasons.

- The terms of future contracts are hard to predict. Perhaps the best guess would be to set future contract prices at the prevailing market price. Unless the model assumed detailed rules for entering into fixed-term contracts -- the begin date and duration of the contracts, the amount of transmission left to accommodate the contract, and so forth -- the terms would have to float with the market price. In this case, however, the value of the contract would then be zero. That is, there is no point to explicitly modeling the contract.

- Contracts for regional load-serving entities and regional IPP capacity with parties outside the region would remove sources of contracts for regional parties, but arguable displace other sources outside of the region. Given the load diversity in the WECC, it stands to reason that contracts for power will continue to be more abundant in the winter, when the region needs the capacity.

Thus, while future contracts for energy out of the region could affect economic risk by hedging price risk and removing or adding contracting counterparties for the region, the model does not capture this. The practical limits on knowledge of existing and future terms and the small likelihood that such contracts would significantly diminish the pool counterparties for regional participants are significant hurdles to such modeling.

Before leaving this section, note that the value or cost associated with contracts accrues to the region in the base case model. As the reader will note in the discussion of the regional IPP sensitivity (Appendix P), this is not always the case. That is, the energy of contracts may affect the energy balance of the region before any counter-scheduling, but the associated costs may be excluded from the region's cost estimate. This occurs, for example, if the regional IPPs have firm contracts to export energy out of the region. This obligation is on the IPPs -- not the region -- and should not affect regional costs. The energy export will offset the generation of the IPPs in the region, however.

## Supply Curves

The model uses supply curves to represent conservation and price-responsive hydro. For the purposes of the regional model, conservation is either discretionary or of a lost-opportunity nature. Price-responsiveness of hydrogeneration refers to a limited capability to shift hydrogeneration from month to month in response to wholesale electricity market prices. Do not confuse price-responsive hydrogeneration with what is often called "hydro flexibility," which refers to the ability of the hydrogeneration system to draw below Energy Content Curve (ECC) under adverse conditions for reliability purposes. The hydro flexibility capability of the region is over 7,200 GWh or about 10,000 MW-mo. The region uses this flexibility for severe situations, like extreme winter load conditions, and it comes usually at the cost of some non-hydrogeneration use of the system, such as fish survival enhancement. On the other hand, the magnitude of price-responsive hydrogeneration response is relatively small, about 1500MW-mo. Price-responsive hydrogeneration reflects adjustments that operators would make in anticipation of market conditions, and they perform these adjustments with energy above the ECC.

### Background

To begin the description of the supply curve logic, consider the physical and economic situations to be modeled. The first example is lost-opportunity conservation, including a more detailed discussion of the model determines cost from the supply curve. The section then describes the examples of discretionary conservation and price-responsive hydrogeneration.

Lost opportunity conservation consists of energy saving opportunities that are available for only a limited time. Examples of these include insulating and the installation of high-efficiency heating and cooling systems in new buildings. After their construction, going back and changing the conservation measures in these buildings would be cost prohibitive. Special attributes of this kind of resource are the following:

- Assuming the same measures are available to all new buildings, there is effectively a new supply curve in each period. The supply curve consists of the aggregation of a host of measures, such as lighting, new insulation, and other energy efficiency programs, each of which has its own costs and potential. Each new generation of building in principle presents the opportunity to pursue the entire range of measures. Thus, the supply curve represents perennial increments of new opportunity available in the period, unaffected by prior conservation activity.
- The *decision* about how much energy conservation to pursue is independent of prior decisions about other lost opportunities. That is, cost effectiveness depends only on prevailing prices for electricity, not on prior conservation actions.
- Any period costs and energy savings are *accrued*. Costs and energy savings associated with period activity add to those already obtained to arrive at the total current cost burden and energy for the period. The total cost and energy from lost-opportunity conservation in a period is therefore the ***cumulative*** period activity cost and energy up to and including that period. Clearly, we would not assume that the aggregate of these would be non-decreasing as we go forward. Note that accumulating cost relies on the choice to use levelized costs; if the model had used cash flow instead, this would not be the case.
- It is reasonable to assume that the supply curve from which these energy saving measures remains unchanged from period to period. The only exception to this last observation is for changes in the overall potential for lost opportunity conservation. During a period of economic downturn, for example, loads may become depressed and the number of buildings -- and consequently the amount of lost opportunity conservation -- would diminish.

The model obtains the costs for lost-opportunity conservation from the supply curve in particular fashion. Now, clearly a contractor does not pay the same for energy savings from all sources. A contractor does not pay the same for the energy savings from compact fluorescent lights as he or she would for high-efficiency heating. Instead, the amount paid for energy savings from compact fluorescent lights is their market price. This rather obvious observation has implications for how supply curves will yield costs, as we will see in the following example.

Suppose that the prevailing market price for energy is \$60/MWh. At this price, given the supply curve in Figure L-28, the annual cost-effective level of conservation would be 70

MWa. If this were the supply curve of some commodity in a market, the cost of the purchase of this commodity would be $36,792,000, i.e., the 613,200 MWh in a year times the market-clearing price of $60/MWh.

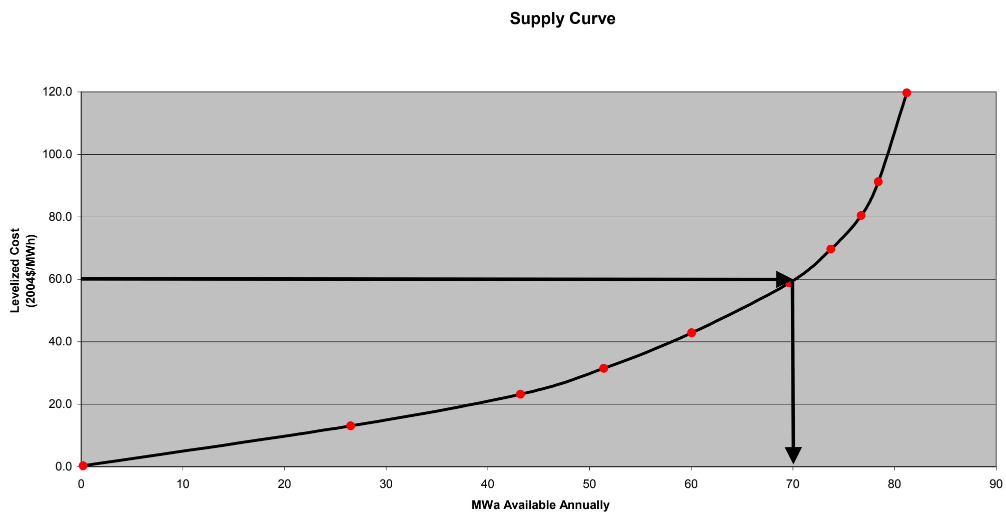



**Figure L-28: Supply Curve**

For the cost of conservation from a supply curve representing a host of distinct measures, however, the total cost associated with the conservation is the accumulated cost of each measure along the supply curve below the cost-effectiveness price, as illustrated in Figure L-29. This cost is much smaller, $13,467,624, although the value of the energy would still be $36,792,000, as estimated before. We will borrow the economist's term for this

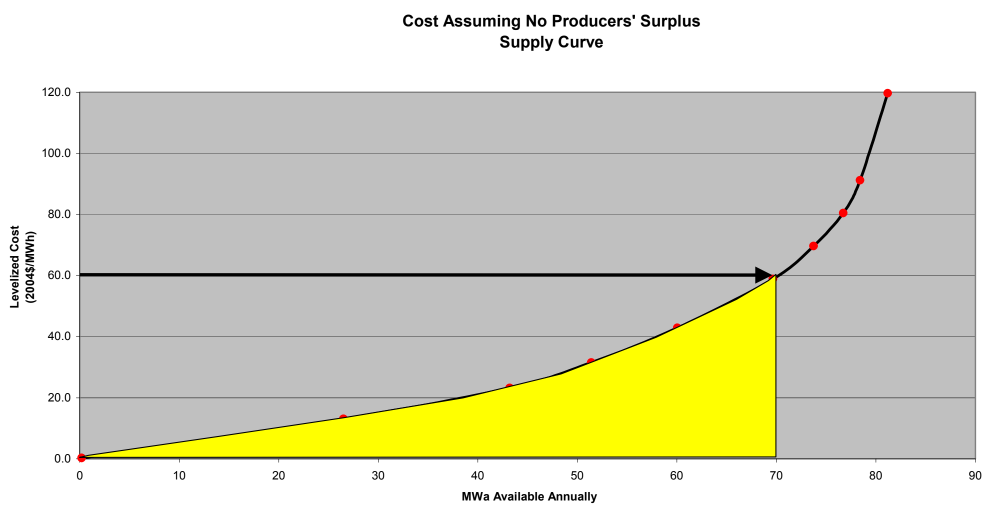



**Figure L-29: Costs Associated with Supply Curve**

cost, the "cost, assuming no producers surplus." This is how the model computes the costs of conservation.

**Contrast lost-opportunity conservation with discretionary conservation measures.** Discretionary conservation measures are the second example of the application of supply curves in the portfolio model. Discretionary conservation measures are those that can be performed cost effectively at any time. Examples of discretionary conservation include changing out low efficiency lighting for high-efficiency lighting in existing buildings. The Council's definition of discretionary conservation does not include new discretionary conservation that will arise from improvements in technology or opportunities for cost effective retrofitting in new construction. Instead, assessment of discretionary conservation is a snapshot in time representing conservation that exists at that point in time. It is therefore a very conservative estimate of discretionary conservation available in the future.

As with lost opportunity conservation, we would not assume that accumulated costs and energy savings could diminish as we go forward. The energy and costs reported in a period are the ***cumulative*** amounts due to decisions in all prior periods. Also, the costs associated with discretionary conservation are derived from the supply curve in the same way as were those for lost opportunity conservation. That is, they are costs assuming no producers' surplus. In several other regards, however, discretionary conservation differs from lost opportunity conservation.

- The conservation that is available in each period is directly dependent on prior conservation activity. A measure can be implemented only once, and once implemented is no longer available as a future development option.
- A single, unchanging supply curve represents total conservation available throughout the study period. Only as market prices rise above prior “high water marks” does additional conservation become cost effective.
- The highest prior cost-effectiveness level therefore determines both the energy and cost of total conservation available in that period. In the case of discretionary conservation, the costs and energy in Figure L-29 would represent the cumulative cost and energy due to all the prior conservation action taken up to the present, not the period’s addition of cost and energy as in the case with lost-opportunity conservation.

The third and final example is that of price responsive hydrogeneration. When system operators are making decisions about how much water to send through the dams, they must consider several factors. The amount of water that they have at their disposal is limited. Moreover, while they may allow temporary excursions from target forebay levels, they are responsible for assuring that the ending levels are on target. Given these constraints, they may use that water now -- possibly drawing down forebay levels -- to generate electric power, which they will sell on the market at the prevailing market price, or they may withhold the water until market prices are higher. Operators do not have perfect foresight about future prices. Experience with daily and weekly variation in prices and with the effect that other events have on electricity prices, however, help shape their expectations.

Even assuming perfect foresight, optimizing the economic value of this storage is challenging. There are, for example, minimum and maximum constraints on generation and stream flow. The portfolio model does not attempt any such optimization. Instead, the portfolio model logic borrows from that of earlier Council models, Genesys and the SAM model. In these models, the decision to draw down or withhold hydrogeneration is based on the comparison of prevailing market prices to prices associated with various blocks out of regional, thermal generation. The assumption is that if storage is drawn down below an equilibrium level, then some form of thermal generation will be needed to restore the hydrogeneration system to its equilibrium state. The further down the hydro system is drawn, the more expensive the replacement energy. Similarly, if current storage is in surplus, the associated energy is inexpensive.[19]

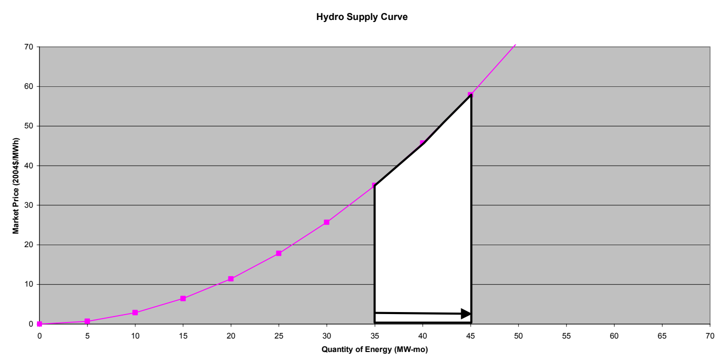



**Figure L-30: Price-Responsive Hydro**

The supply curve associated with price responsive hydrogeneration, therefore, is a reversible supply curve. At the beginning of the study, the supply curve will start out with an equilibrium state, that is, a starting market price and energy level. If market prices rise above the starting price, the market prices is compared to the starting price and energy is made available up to the higher market price. Figure L-30 illustrates the situation where the starting price was $35/MWh and current market price is $58/MWh. This causes the hydro supply curve to yield 10 MW-mo of energy. The cost of this energy is the increment of cost, assuming no producers' surplus, incurred since the prior period, illustrated by the white area in the figure.

[19] The cost typically is not assumed negative, because some surplus capability always has value as insurance against contingencies such as plant outages. The exception is if the surplus storage would interfere with the flood control responsibilities of the hydrogeneration project.

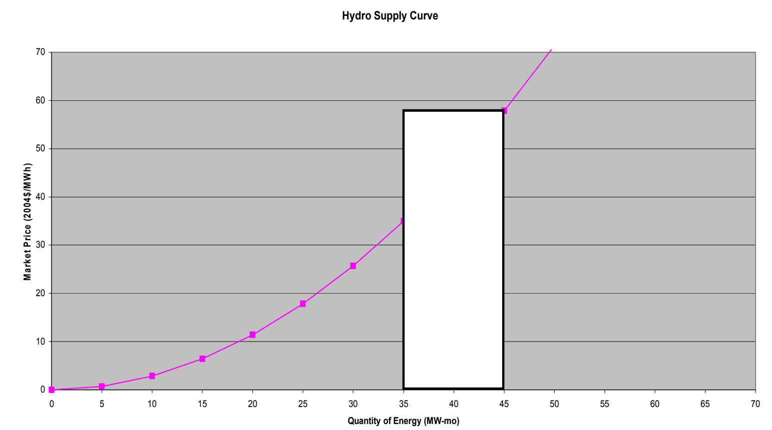



**Figure L-31: Gross Value of Energy**

The gross value of this energy is just the market price times the energy provided, illustrated (with suitable scaling for hours) by the rectangle in Figure L-31. The net value of this energy, therefore is the difference between gross value and cost, illustrated by the remaining triangle in Figure L-32.

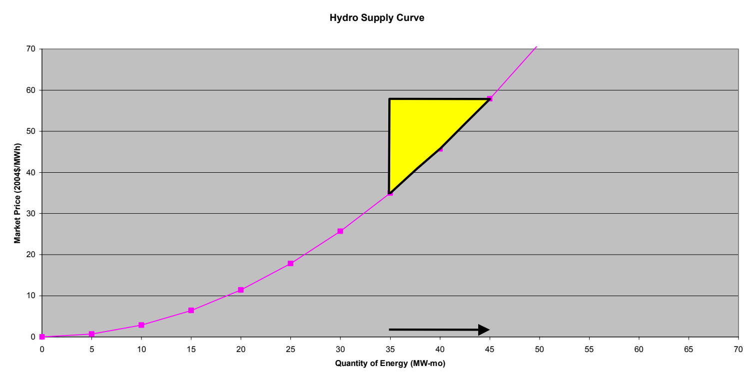



**Figure L-32: Net Value of Energy, Increasing Price**

In the next period, if the market price is higher than the prior period, an increment of energy corresponding to the difference of two prices will be made available. If the market price is lower than the prior period, the operators will effectively "refill" hydroelectric storage. If the system is refilling, the role of market price and supply curve cost reverse. The market price determines cost, not benefit, and the supply curve determines benefit, not cost. This results in the net value illustrated by the triangle in Figure L-33. When refilling, the hydro system puts load on the energy balance. The load will be equivalent to the energy corresponding to the difference of those two prices.

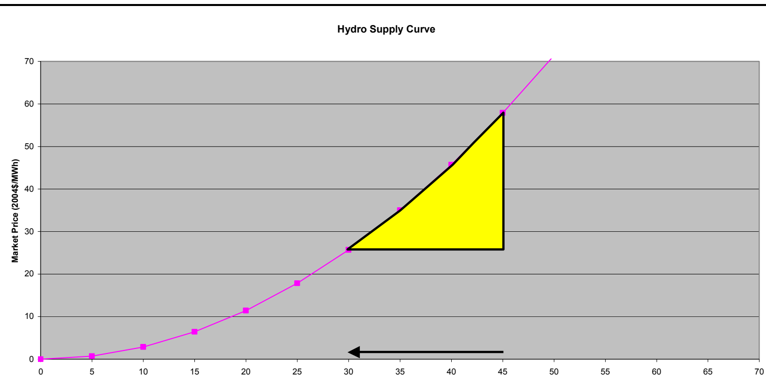



**Figure L-33: Net Value of Energy, Decreasing Price**

The supply curve for price-responsive hydro resembles that of discretionary conservation in that the cost and energy available does depend on decisions made in prior periods. It differs from discretionary conservation, however, in that the supply curve is reversible, and the cost and energy in each period is incremental rather than cumulative. Whereas discretionary conservation energy is all energy along the supply curve up to the cost-effectiveness price, price-responsive hydrogeneration energy is due to electricity market price differences between this period and the prior period. Costs for price-responsive hydrogeneration also depend on these price differences.

Note the following oddity about price responsive hydrogeneration value. The value of the energy is of course determined by market price, but it changes are gradual the market price is very close to the shadow price for that energy reflected in the supply curve. Consequently, as changes are more gradual and smaller the net value of the energy approaches zero. If, on the other hand, changes are abrupt, there is a positive value associated with the hydrogeneration because the gross value is determined by the market price all the cost is determined by the supply curve assuming no producers surplus. If there is an abrupt decrease in market price, however, the cost of the load is smaller than the value associated with restoring the energy to the hydro system. Thus there is a net positive gain or value to the storage, but the size of the gain depends on the size and frequency of adjustments.

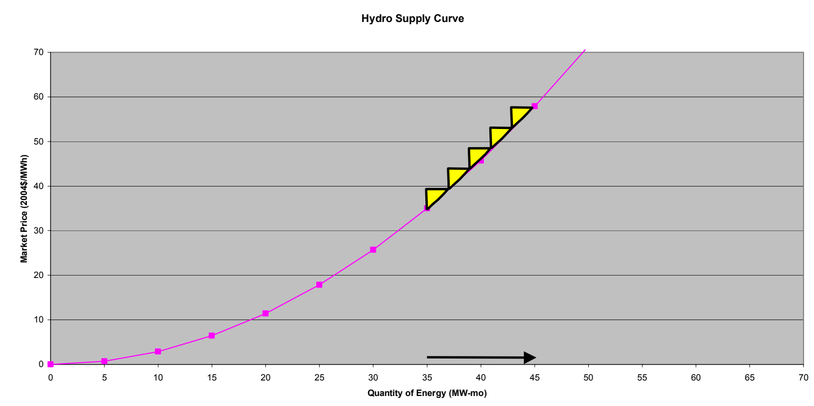



**Figure L-34: Value as a Function of Adjustment Frequency**

Because the value of the price-responsive hydro depends in such a sensitive fashion on the frequency and step-size of adjusts to market price, and because it seemed reasonable the operators made adjustments relatively frequently, the decision was made to ignore the value of the price responsive hydrogeneration effectively assuming that changes are made continuously and are small. This does not mean, however, that the hydro energy does not have value to the system. The primary source of value instead is due to price moderation. As explained in the section "The Market and Export/Import Constraints," on page L-50, the ability of price-responsive hydro to rebalance system energy when the region is close to import and export limits prevents market price excursions. Preventing these excursions has significant value to the system.

Before examining the supply curve logic, consider the similarities and differences among the three applications of supply curves provided above. First, the supply curve may represent period potential, or they may represent the total amount of energy available over the study. An example of the former is lost-opportunity conservation; examples of the latter are discretionary conservation and hydro generation. While period curves may change from period to period, the fixed supply curves obviously can not. Second, supply curves may be reversible, as in the case of hydro generation, or non-reversible, as in the case of both types of conservation. To facilitate discussion, Figure L-35 presents these options as a grid. Lost opportunity conservation would fall in the upper left-hand corner, discretionary (non-lost opportunity) conservation would fall into the lower left-hand corner, and price-responsive hydro would fall into the lower right-hand corner.

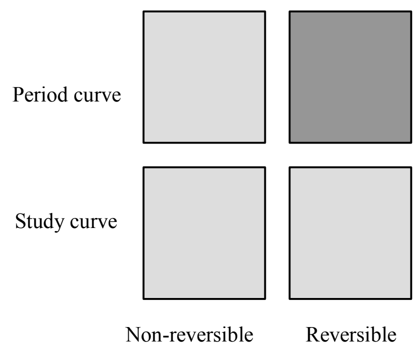



**Figure L-35: Supply Curve Options**

One question that arises is, “Does it makes sense to speak of a reversible, period supply curve?” This case would lie in the upper right-hand corner, which is slightly darker in Figure L-35. For this to be feasible, circumstances must arise where the supply curves for adjacent periods have at least one point in common, the access point. Because period curve can potentially change from period to period, however, this common point would typically change each time the curves are used. Because of the complexity of this situation, and because no physical systems come to mind which might require this representation, it is excluded from further consideration.

There is one more aspect of supply curves that Figure L-35 does not address. The energy and cost returned in a given period may either be the cumulative amount due to all changes in prior cost and energy, or may be the increment of cost and energy only due to changes in that period. In the former case, the incremental change adds to the cost and energy incurred up to the current period. Figure L-36 illustrates this additional dimension. The combination representing a reversible, varying supply curve is missing from this illustration, consistent with the exclusion described in the preceding paragraph. The three kinds of supply curves used in the regional model now correspond to the lighter-colored boxes in this figure. Price-responsive hydro now falls in the row of boxes associated with incremental costs and energy, behind the row of boxes associated with cumulative cost and energy.

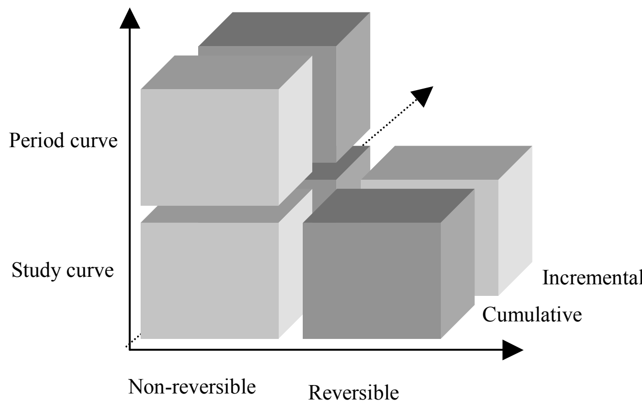



**Figure L-36: Aspects of the Supply Curve**

This concludes the discussion of supply curve concepts requisite to understanding the computer model. The subsequent material describes the use of functions that perform the tasks of computing the energy and cost.

Conservation

Before each game, the worksheet model must initialize several arrays of data that the supply curve worksheet function accesses. These arrays contain a description of the supply curve in each period and look-up values for cost. The description of the supply curve appears in {row 376}. The supply curve changes only if there is a new entry in the column corresponding to the period of interest. For lost opportunity conservation, the supply curve changes several times, including during this period. (See {AQ377}.) The supply curve syntax is

0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102,

which represents a piece-wise linear supply curve defined by five points. The points are separated by the special characters "@+". The second point, for example, is (5.075,15.5), where the first coordinate is the energy in MW (Q is 5.075 MW), and the second coordinate is the price in $/MWh (P is $15.5/MWh in 2004$). Because this supply curve represents quarterly increments, each Q value is one-fourth the annual capability. The description of the data development for these supply curves appears below, in the subsection "Resource Implementation and Data," of the section "Resource Implementation and Data," on page L-92.

Other information loaded at the beginning of each game appears in the range {F376: P377}. Column F contains the "curve type." The curve type is an integer -- 0, 1, or 2 -- representing to which category in Figure L-35 the curve belongs. (See Figure L-37.) Column G contains the integer 0 or 1, denoting the incremental or cumulative treatment of energy and cost, respectively.

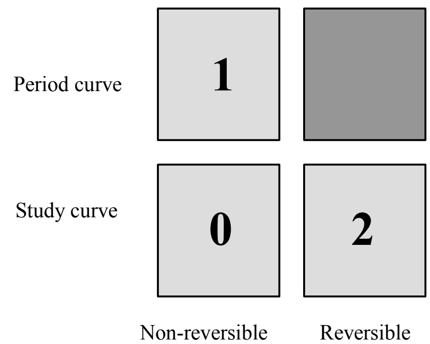



**Figure L-37: Curve Type**

All supply curves extrapolate indefinitely in both directions unless terminated by endpoints. Upper and lower prices define the endpoints. Column H contains the upper price; column I contains the lower price. Arbitrarily small and large numbers define unbounded curves.

Changes in energy from period to period may be constrained to a maximum rate. The maximum rate of change, or "ramp rate", is specified in column J. If no constraint is intended, use an arbitrarily large value.

Columns K through O specify initial conditions for cumulative and incremental cost and energy. These initial conditions play an important role in specifying the starting place for price-responsive Hydro. For both kinds of conservation, the initial values are zero.

The last parameter is an index that specifies to which supply curve this data pertains. This index appears in column P. The supply curve workbook function use this index to determine which portion of data arrays to access and modify.

The first row in the period containing an example of the worksheet supply curve function is {row 377}, where the on-peak energy for lost opportunity conservation is estimated. The formula in cell {AQ377} is

```
=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)
```

The first constant is the number of hours on peak. The second, 1.402, is the on-peak weight for lost opportunity conservation. Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection "Supply Curves" of the section "Resource Implementation and Data," below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of this weighting factor appears in that section.

To understand the last factor, it is necessary to follow the parameters in the call to the function, defined as follows

Function sfSupplyCurve(ByVal sPrice As Single, ByVal lCurve As Long, ByVal lPeriod As Long, ByVal dummy As Single, Optional ByVal sProportion As Single = 1) As Single

```
===============================
Takes:
sPrice -   Price in $/MWh
lCurve -   index to unique supply curve
lPeriod -  0-based index into period
dummy  -   Forces the order of calculation
sProportion - multiplier for Lost-Opportunity supply curves only
===============================
Returns:
A single with the amount supplied, MW
```

The first parameter in the function call in cell {AQ377} is AP$233+$R$375, the price used to access the supply curve. This sum points to a decision criterion in the previous period (AP$233) and a constant over which the optimizer has control ($R$375). The optimizer can adjust this latter constant, which is a premium over decision criterion price, if doing so reduces cost or risk. A brief description of this appears in Chapter 6.

This is the first time we have encountered a situation where a function or formula accesses a price or decision criterion in a prior period to determine response. The complete discussion of this practice is in the section “Concept Of Causality,” below, and description of the decision criterion is in the appropriate subsection of the section “Decision Criteria.” Briefly, however, the decision criterion for lost opportunity conservation is a non-decreasing, average market price over five years. This is intended to reflect the fact that decisions to modify such programs, such as building code changes, usually take awhile, but much of the measure gets institutionalized into standards and building codes. It is much less typical to make such decisions based on *current* market prices.

The second and third parameters in the function call in cell {AQ377}, $P377 and AP$46, point to the curve 0-based index and the prior period’s 0-based index, respectively. That is, the first supply curve has index 0, the second curve has index 1, and so forth, and these curves may appear in any order in the worksheet. Similarly, the first period (Sept-Nov 2003) has index 0, the second period (Dec 2003-Feb 2004) has index 1, and so forth. These are simply used to organize data in an array that holds data for all supply curves and all periods.

The fourth parameter in the function call in cell {AQ377}, AP377, points to the supply curve formula in the preceding period. This is a dummy reference that forces Excel to calculate the prior period’s supply curve value *beforehand*. An internal, cell-dependency tree specifies the order of formula evaluation in a worksheet. This tree assures that when calculation takes place, only those cells that have changed -- and any cells that depend on those cells -- recalculate. This saves recalculation time, but renders the order of cell recalculation and function call unpredictable. Because conservation in one period depends directly on conservation in prior periods, calculations and supply curve function calls must occur in strict chronological order. The dummy reference assures chronological firing of function calls.

The fifth parameter in the function call in cell {AQ377}, AP240, scales the quantity of the lost-opportunity supply curve. As mentioned earlier, such things as downturns in building construction affect lost-opportunity conservation. To capture this, the model uses percentage change in load as a surrogate for these effects. If loads increase one percent relative to the benchmark load, lost-opportunity supply potential increases one percent at all price levels. Clearly, the *recently past* change in load affects the potential for lost-opportunity conservation.

The period cost of lost opportunity conservation lies in cell {AQ378}. The supply curve function sfSupplyCurve computes all costs when it computes energy. A simple function in {AQ378} simply retrieves that information from data arrays. The content of {AQ378} is

=(sfCostCurve(AQ377,$P377,AP$46)*1152*1.402-AQ$207*AQ377)/1000000

This formula is valuing the on-peak conservation energy in the market and converting the value to millions of dollars. As elsewhere, cost is positive and value is negative, so this formula computes cost less gross value, rather than gross value less cost. There are two terms in the numerator. The first term is

sfCostCurve(AQ377,$P377,AP$46)*1152*1.402

which represents the cost of the conservation in real levelized dollars for the period. (See page L-16, ff. for a discussion of the use of real levelized dollars.) The supply curve function has already multiplied the $/MWh value by the MW obtained from the supply curve, yielding real levelized $/hr which sfCostCurve(AQ377,$P377,AP$46) reports. Again, the real levelized $/hr is multiplied by the number of hours in the standard on-peak period and by the weighting factor.

The function sfCostCurve has the following syntax:

```
Function: sfCostCurve(ByVal dummy As Single, ByVal lCurve As Long, ByVal lPeriod As
        Long) As Single

Purpose:  Retrieve costs that were calculated by sfSupplyCurve

==============================
Takes:
dummy  -   Used only to re-trigger the fetch of cost information; Excel
           will call this function after the sfSupplyCurve function
           has been updated
lCurve -   Unique integer identifying curve
lPeriod-   Unique integer identifying period
------------------------------------------------------------------
Returns:
   A single with cost (value) in $/hour real.  The value already reflects
   the rate of energy supplied
```

The first parameter references the supply curve function, to assume that function has been updated before attempting to access the associated costs. The second and third parameters merely access the 0-based period and supply curve indices to permit the function to locate the data in the memory arrays.

The second term in the numerator is AQ$207*AQ377. This is the gross value of the energy. The cell {AQ$207} contains the relevant on-peak market price for electricity in the period; the cell {AQ377} is the on-peak conservation energy, which has already been adjusted by on-peak hours and weighting.

Similar calculations exist for off-peak energy and cost. The energy calculation in cell {AQ741} is

=AQ377*864*0.465/1152/1.402

which determines the off-peak energy contribution. The MWh off-peak is the product of off-peak hours (864) and weighting (0.465) applied to the MW rate. The MW rate, in turn, is the MWh on peak after removing the on-peak hours (1152) and weighting (1.402) factors. The calculation of costs off peak is the same as on-peak, with appropriate substitutions for off-peak hours and weighting:

=(sfCostCurve(AQ741,$P741,AP$46)*864*0.465-AQ$219*AQ741)/1000000

The allocation of gross conservation costs on and off peak is a bit of a fiction, but reader should be able to convince himself the distribution does not matter as long as the total gross cost is correct. The benefit, due to allocation of energy on- and off-peak, however, is critical.

Discretionary conservation energy and cost calculation is similar to lost-opportunity calculation. Before the game, the workbook reads a single supply curve from cell {R385}. It reads other information from the range {F385:P386}. Most of the parameters in this range are identical to those for lost-opportunity conservation. The two exceptions are the choice of "curve type," cell {F386}, and the ramp rate, cell {J386}. The curve type conforms to the type of conservation, as illustrated in Figure L-37. The ramp rate, expressed in MW per quarter, is a constraint that limits the amount of conservation that can be added in each quarter. This constraint is essential, because of the low cost of discretionary conservation programs. If the supply of energy were not constrained, almost half of the energy available in the curve, roughly 1500 MW, would be implemented in a single quarter. Clearly this is not realistic. For several reasons, including cash flow constraints, rate impact constraints, and limits of available resources for pursuing such programs, the model employs this ramp rate.

Price-Responsive Hydro

As for conservation, the worksheet model initializes the supply curve-worksheet function for price-responsive hydro before any games. The description of the supply curve for hydro is fixed throughout the study and appears in cell {R528}:

-250,5@+0,30@+250,60

The supply curve syntax is just as for conservation. As with lost-opportunity conservation, this supply curve represents quarterly increments. In this case, the supply curve has a zero quantity at $30/MWh, but this is somewhat arbitrary, because only differences in quantities on the supply curve get used. The supply curve, in fact, stops at $5/MWh and $60/MWh, as explained below. This means the total amount of energy available from the curve, obtained by a swing in market price from $5/MWh to $60/MWh, is 500MW, or 1,008 GWh (500MW * 2014 hours per standard quarter). Compared to the hydroflexibility limit for the PNW hydro system, about 7200 GWh, this is a small value, as it should be.

The other data loaded before simulation, in range {F528:P529}, differs significantly from what the model has for conservation. As explained earlier in this section, the curve type and treatment both differ from what we use for conservation. This combination of values assures the model uses a reversible supply curve and the user-defined function (UDF) returns only the incremental energy and associated increment cost between the current and the immediately prior year.

Upper and lower price limits (cells {H259} and {I259}, respectively) reflect the assumption that the amount of energy available for shifting is constrained. The values here match the endpoint values of the supply curve, although that is not a constraint of the model.

The initial price (cell {O259}) is set to $30/MWh, the midpoint of the supply curve. Recall that the energy provided by the supply curve is determined by comparing the period electricity price against a baseline, the price in the prior period. In the first period, however, there is no prior period, so an “initial price” must be specified. That is the purpose of this parameter. Its value is somewhat arbitrary, but it has been set to the rough, average cost of electricity at the beginning of the study. After several periods, this value of this initial price probably becomes immaterial to energy calculations.

Note that in cell {AQ529}, the price for accessing the supply curve ({AQ$224}) is the *current* price, not the price or criterion function value in a prior period:

```
=sfSupplyCurve(AQ$224,$P529,AP$46,AP529)*1152
```

This is a departure from the case for conservation. This is consistent with how we expect that price-responsive hydro would behave. Any generation or refill would be to avoid or take advantage of *current* market prices.

## Conventional Hydro

Hydrogeneration is a key uncertainty, due to its reliance on variable stream flows and weather. For this reason, the discussion of the user-defined function (UDF) that provides these energy values appears in Appendix P, instead of here. Appropriate for discussion here, however, is how the MWa provided by the hydro UDF influences the costs and energies in the portfolio model.

As described in Appendix P, the UDF returns east-side and west-side generation separately. The west side, on-peak hydrogeneration formula in cell {AQ437} is

```
=$R$136*$AQ$36
```

The first term in this product points to the constant 1.0. This is a vestige of logic in Olivia that provides the user the capability to scale hydrogeneration. The second term points to a cell, {$AQ$36}, containing simple conversion from the MWa returned by the UDF, {AQ33}, to MWh:

=AQ33*1152

Finally, the cost is the inverse of the value of the hydrogeneration in millions of dollars. Because the model assumes no variable cost, the value is just the MWh times the market price in $/MWh from cell {$AQ$204}:

= -$AQ$36*$AQ$204/1000000

Identical calculations exist for east-side hydrogeneration, rows {594} and {595}, and for off-peak generation on the west side, rows {798} and {799}, and on the east side, rows {951} and {952}.

## The Market and Export/Import Constraints

The portfolio model assumes that dispatchable resources respond to market prices for electricity.[20] When a power system is unconstrained by transmission or other import/export limitations, one typically does not have to worry about whether a given market price is somehow infeasible. This situation may exist for individual utilities that consider themselves price takers in a relatively deep market for electricity. Higher prices simply mean more generators will run.

The region as a whole, however, is different. If a lot of generation is added to the region and exports are constraining, prices must fall to balance demand. Price is no longer an independent variable.

A regional model that incorporates market price uncertainty lies somewhere between these extremes. Electricity prices are neither completely independent nor completely dependent of other variables. As the reader will see, at least one other variable must typically play the role of a "slack variable," so that the pair is dependent. In the Council's portfolio model, the slack variable is net exports.

When Monte Carlo simulation selects an electricity price for the regional model, it may not be feasible. If the price is high, the resulting generation, after exports, may be surplus to requirements. Energy must be conserved, however: energy consumed must equal energy produced. In this example, the price must be adjusted downward until the situation becomes feasible. The situation will be feasible when generation equals loads plus exports. Similarly, if the price is high, the resulting generation, after imports, may be inadequate for our requirements. The price must be adjusted upward.

[20] Strictly speaking, the assumption is that dispatchable resources respond to some explicit, widely visible signal of generation value. In the world before price deregulation, the measure of merit was "system lambda," which indicated the variable cost of generation on the system. Regulators among others sometimes refer to this concept as the "avoided cost." Economists refer to this kind of value as a "shadow price." It simply represents a means for assigning value to alternative means to meeting system requirements or the requirements of others. In describing the portfolio model, all of the arguments work if one substitutes these identical concepts for that of deregulated market price for electricity.

RRP algorithm

The Resource-Responsive Price (RRP) algorithm in the model finds a price that balances the system's energy. It does this by iteratively adjusting the price. Figure L-38 illustrates this process in the case where prices start out too low and upward adjustment is necessary.

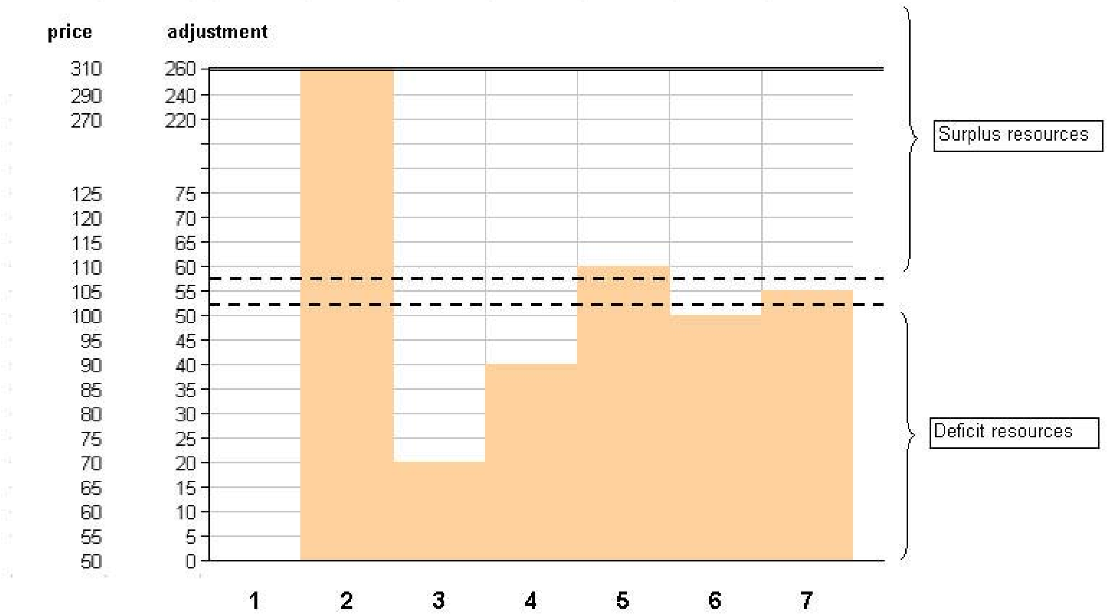



**Figure L-38: RRP Algorithm Finds Price Iteratively**

In this example, a random draw of electricity price yields $50/MWh. At this price, however, the system does not have enough generation to meet its load, even after all possible imports. The vertical axis is the price adjustment, from zero to $260/MWh. Next to the vertical axis are values representing the electricity price. Before any adjustment, the electricity price is $50 a megawatt hour. The difference between the two columns is the initial starting place of $50 a megawatt hour. Along the horizontal axis are the steps in the iteration process. At step number one, there is no adjustment. There are three horizontal lines on this graph. The first line, level with an adjustment of $260 per megawatt hour, represents the maximum possible adjustment. This corresponds to electricity market price of $310. As we will see shortly, this maximum price is the user-selected value. The second line, level with an adjustment of about $57 per megawatt hour, represents the lower limit of price adjustments that would produce resource generation surplus to our requirement. Above this price, resources would generate an amount of electricity that would exceed our ability to export energy surplus to our requirements. The third line, level with an adjustment of about $52 per megawatt hour, represents the upper limit of price adjustments that would result in generation inadequate for our system. Below this price, resources would not generate sufficient electricity to meet our requirements, even after importing the maximum possible energy. The distance between these latter to lines is quite small, atypical of situations that arise. The situation, however, will help us illustrate how the RRP algorithm works.

In step one, the worksheet determines that generation is deficit to our requirements. (The value that determines whether the system is surplus or deficit during the on-peak subperiod lies in a row {678}. A complete description of the functioning of the workbook and the formulas appears later in this section.) In step two, the algorithm tries the largest possible price adjustment. If the system is still deficit resources, the algorithm stops and uses this largest price. If the system is no longer deficit, the algorithm proceeds to step three. In steps three through five, the adjustment is moved upward by equal increments until the system is no longer deficit. If the system were in balance at this point, the algorithm would stop and use that adjustment. In step five, however, the adjustment was large enough that the system is now energy surplus. The algorithm now changes search strategy. Instead of using even steps, the algorithm uses a binary search strategy. In step six, the algorithm takes the value halfway between those in steps four and five. In step six, however, the resulting adjustment again overshoots the region where the system would be balanced. The algorithm then tries an adjustment halfway between those in steps five and six. The resulting price adjustment now balances the system (step seven), and the algorithm stops. This final adjustment is used.

The increment size used in steps three through five is a pseudo random value. It is chosen to be relatively small compared to the price. The algorithm uses the approach of equal size to increments at the beginning of the search process in order to arrive at a final adjustment that is only slightly above the largest adjustment that would result in deficit resources. Experience has shown us that using a binary search throughout this process produces a price adjustment close to the middle of the vertical scale in a very large number of instances. This in turn produces unnatural price probability distributions. Using even increments early in the search process brings us closer to the minimum adjustment that would balance the system, and that turns out to be a much more variable value.

If the system had started out to surplus instead of deficit, an identical search process would be used except that the algorithm would use negative adjustments to price. Instead of the maximum adjustment, the algorithm would use the starting price as the maximum negative adjustment.

To relate these observations back to the workbook, first consider Figure L-6. Recall that there are three regions in the workbook where distinct kinds of calculations are made. At the top of the workbook are the cells associated with futures. These are calculated only once, at the beginning of each game. Below this lie the twilight zone (TLZ) rows, in which each column will be updated iteratively whenever a subperiod's calculations update. (The TLZ is in fact defined by the Parameter section at the bottom of the worksheet.[21]) At the bottom are the rows in which the RRP algorithm iterates to a

[21] In range {Q1328:R1370} (range name, "Parameters"), there appear a list of variables that control the operation of the workbook. The top of the Twilight Zone is determined by the row number, 203, associated

feasible price. There is one set of rows for on-peak calculations and another for off-peak calculations. We are concerned with those rows in which the RRP iterates.

Consider the operation of the algorithm on on-peak prices. The relevant range of cells in the workbook is {AQ215:AQ678}. The algorithm starts with a zero adjustment in cell {AQ215}. The algorithm, which resides in a VBA module, modifies the value of this cell. This adjustment is then added to the on-peak price for the Eastern region in cell {AQ216}. The on-peak price for the Western region, in cell AQ219, is a simple percentage increase over the Eastern region price. This percentage increase represents transmission losses and wheeling costs. The electricity price in cell AQ216 will be then used by all resources in the Eastern region.

The net on-peak requirement for the system is calculated in cell AQ676. This is the on-peak load, including DSI load, less all generation.

> =AQ322+AQ328-AQ339-AQ349-AQ359-AQ367-AQ377-AQ386-AQ397-AQ407-AQ417-AQ428-AQ437-AQ460-AQ474-AQ488-AQ499-AQ511-AQ521-AQ529-AQ538-AQ545-AQ555-AQ565-AQ575-AQ586-AQ594-AQ604-AQ614-AQ625-AQ635-AQ645-AQ655-AQ665

The net on-peak requirement met through imports is calculated in cell AQ677. This is where we see the adjustment for contracts, through {AQ367}. That is, if there is imported, contract energy in this period, an adjustment to the export capability is made for counter-scheduling potential.

> =MIN(1152*6000-AQ367,MAX(-1152*6000-AQ367,AQ676))

The portion MAX(-1152*6000-AQ367,AQ676) limits exports to 6000 MW, before adjustment for contracts; the rest limits imports similarly.**5** The difference between the net on-peak requirement and the requirement met through imports is calculated in cell AQ678. This amount is the deficit the used by the RRP algorithm.

> =AQ676 - AQ677

If system generation were surplus to load requirements, the value in cell AQ676 would be negative. Again the amount of surplus met by exports would appear as a negative value in cell AQ677. The difference between these values would be the net remaining surplus. It would appear as a negative value in cell AQ679, which would signal the RRP algorithm to find a downward price adjustment.

In range {Q1328:R1370} (named "Parameters"), there appear a list of variables that control the operation of the workbook. The variable "dMaxPriceAdj"' a misnomer, has a value of 250. This is actually the maximum price, in $/MWh. The maximum adjustment will be the difference between this value and the original price. Also, when using an iterative technique for solving the problem such as this one, it is useful to know whether a solution is "close enough." The algorithm is searching for a feasible price, so searching

---

with the variable "lTopHeaderRow." The bottom of the Twilight Zone is specified by the row number, 320, associated with the variable “lBottomHeaderRow."

to the penny is neither necessary nor desirable. The variable "dEnergyTol", here set to 100 MWh, is the threshold. That is, if the surplus or deficit is less than 100 MWh, the RRP algorithm will stop refining its adjustment. (The variable "dEnergyTest" in the Parameters list is no longer used.)

The duality between price and import-export capability is now evident in Figure L-38. If there were no import-export capability, only one price would balance the system. Electricity price would be a dependent variable. Conversely if import/export capabilities is unlimited, the price is completely independent. Any price, in principle, is feasible. The RRP algorithm is not necessary.

The relationship between price and import/export capability has additional significance. The import/export capability determines how much random variability is feasible for market price. If there is no import/export capability, there can be no stochastic variation in market price for electricity.

Another issue related to RRP is capacity expansion and portfolio choice. Consider the situation of a single load-serving entity, a price taker in the wholesale electricity market. Assume this entity wants to make resource addition based on economics, as the regional market does. Any resource that makes money on average will of course appear attractive and the optimizer will add it. If resource addition does not depress prices, however, there is no reason to stop there. If one is good, two is better. This process would continue without end. That is, there could be no solution to the capacity expansion problem. If market prices are, on average, lower than the cost of a resource, the optimizer may add that resource if the resource reduces risk, even though it raises cost. It should be evident, however, that without RRP, the issue of portfolio choice depends in a more delicate fashion on the relationship between market price and resource candidate cost. RRP guarantees a reasonable balance because resource addition is limited irrespective of the initial relationship between resource cost and electricity price.

Finally, it may be useful to understand what the effect the RRP has on price for some simple cases. When they were first introduced to this algorithm, the Council staff expected the responsiveness of price to load-resource balance to be constant over the range of balance, perhaps like the resource supply curve in Figure L-39. What they found, instead, was the rather flat response over a significant variation in load-resource balance, as in Figure L-40. Moreover, for difference levels of price, the response was much the same, as shown in Figure L-41. To understand what is going on here, recall from the previous discussion

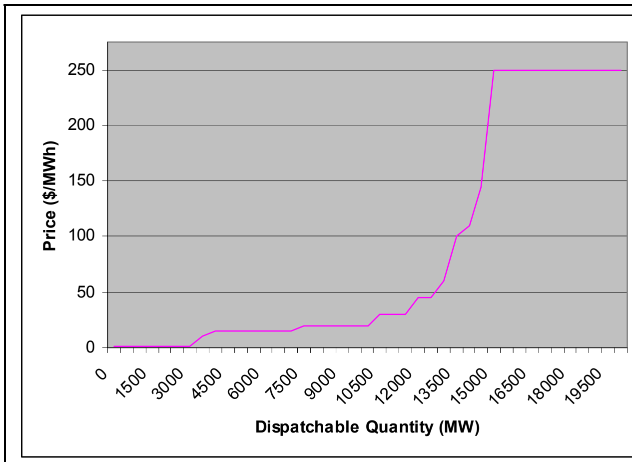



**Figure L-39: Dispatchable Resource Supply Curve**

that the algorithm does not adjust the price unless it is necessary to do so. This permits whatever stochastic relationship may exist between price and other variables, like load, to express itself without modification in most cases. Under what circumstances and how much the algorithm modifies price is a function of the import/export constraints, the supply curve, and of course, the price and load that are drawn.

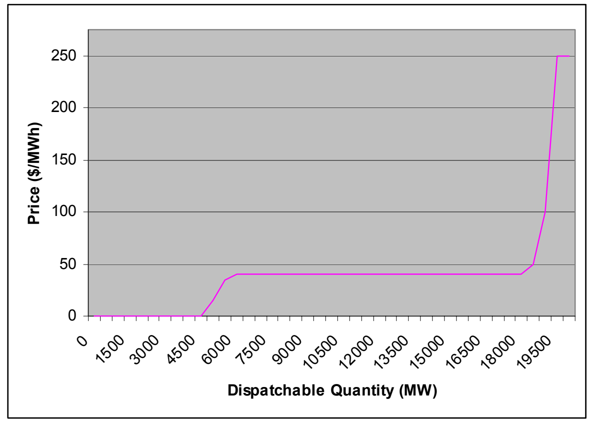



**Figure L-40: RRP Response**

Before proceeding with the description of price sensitivity to load-resource balance, we make the following simplifying assumptions. In practice, both loads and resources are constantly changing and both contribute to the load-resource balance. In these examples, however, we modify only load. Because only the load-resource balance concerns us, this simplification is not a hindrance to our understanding of the algorithm. The simplification makes these illustrations much easier to follow.

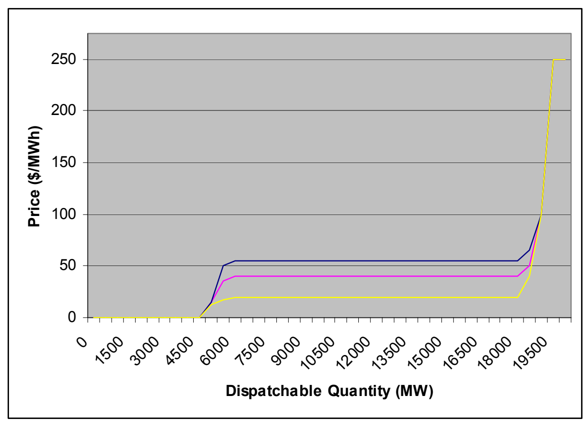



**Figure L-41: RRP Response at Various Price Levels**

The Monte Carlo simulation initially draws the electricity price and load level independently, although they may be correlated values. For whatever price is drawn, there exists a corresponding load, $L_p$ in Figure L-42, determines by the resource supply curve. Absent imports and exports, this is the only feasible load. The supply curve makes load and price dependent variables. If import-export capability exists, however, there is actually a range of feasible loads that could correspond to this price. Below the load $L_p$, for example, native load combined with exports could sum to $L_p$. This is illustrated in Figure L-43. If exports are constrained, however, there is a lower limit on native loads consistent with our price. This lower limit is denoted $L^e_p$ in Figure L-43. Similarly, if imports are constrained there is an upper limit on native loads consistent with our market price. Above this upper limit, it is impossible to import enough energy to bring our net load down to $L_p$. This upper limit is denoted $L^i_p$ in Figure L-43.

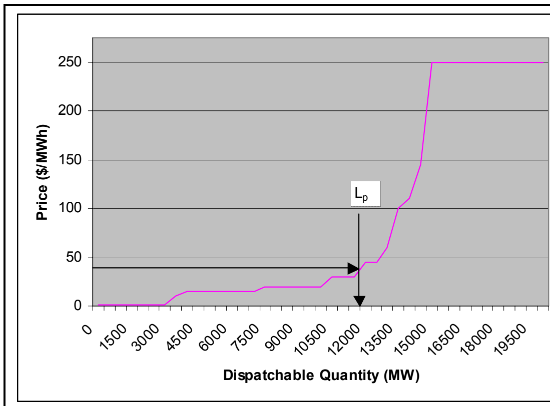



**Figure L-42: Load Corresponding to Price**

For all native loads between $L^e_p$ and $L^i_p$, price adjustments are unnecessary. Imports and exports can explain the difference in net load that results in our initial price.

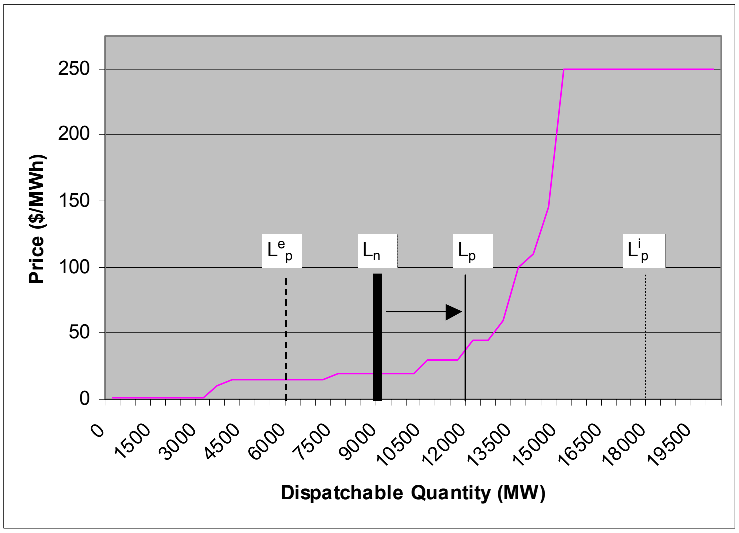



**Figure L-43: Native Load**

What happens if native load is below $L^e_p$, however? Clearly, our initial price and the native load are inconsistent, because the necessary amount of energy could not be exported. (See Figure L-44.) The algorithm adjusts the initial price so that the relationship between price and native load is once again consistent. In Figure L-45, the export limit $L^e_p$ is reduced by 4000 MW to $L^{*e}_p$. This, of course, requires that the load $L_p$ associated with our initial price be reduced by an equivalent amount. The adjusted "price load" $L^*_p$, together with the supply curve, now defines an adjusted price, illustrated in Figure L-46. In fact, any price between this adjusted price and the price associated with the native load is consistent with the native load.

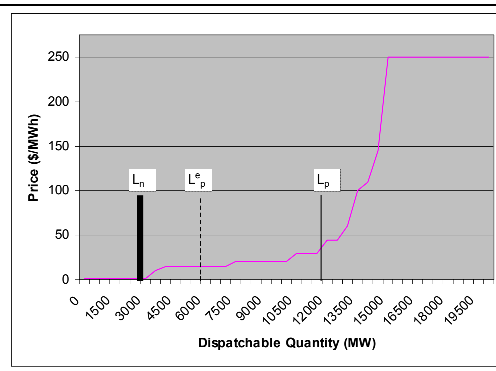



**Figure L-44: Native Load below Export Limit**

We can now see that over a range of loads corresponding to the sum of import and export constraints, no price adjustment is necessary or made by the algorithm. Outside of this range, however, the algorithm applies an adjustment that resembles the supply curve around the price load. Indeed, if there were no imports or exports the response provided by the RRP algorithm would look identical to the supply curve.

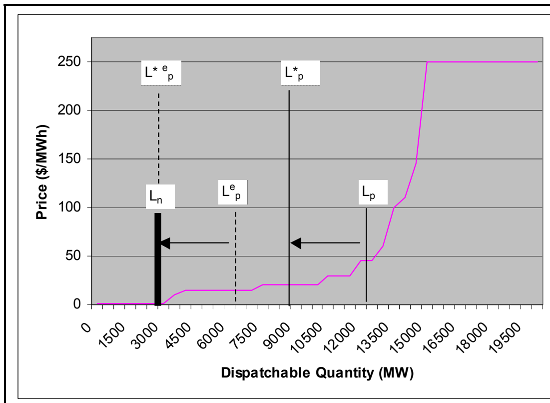



**Figure L-45: Adjusting the Price-Load**

There is a sense in which the RRP algorithm's response to load-resource balance is sensitive over a larger range of balance values, however. In Figure L-48, the average price as a function of the average load exhibits a more gradual response. The reason for this response is that for any average load level, there is some probability that sample loads will impact the load limits described in Figure L-43. There is greater probability of hitting a limit as the average load approaches the limit, and the effect on the average price increases correspondingly. Thus the relationship between average price average load is more gradual. The relationship for alternative price levels is illustrated in Figure L-47.

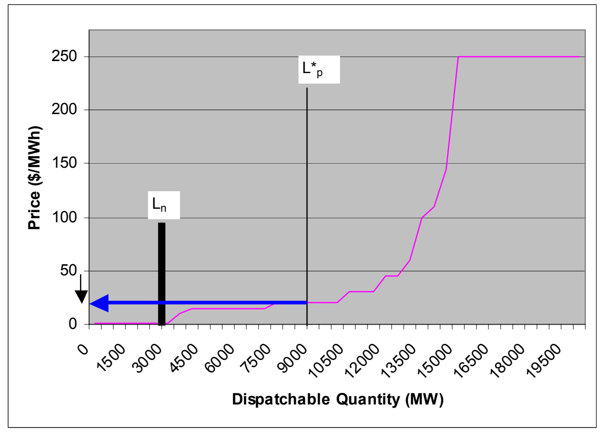



**Figure L-46: New Price, After Adjustment**

In this section, we have described how the algorithm works to acquire a price that is consistent with native loads, resources, and import and export constraints. This section described the duality between the stochastic behavior of electric market price and levels of imports and exports. Although it is possible to forego with the RRP algorithm when there are no constraints on imports and exports, the users must take special care if they want to add resources to the portfolio. In particular, if market prices are higher than the fully allocated cost of capacity expansion candidates, the optimal solution would be to add increments of the candidate without bound. Finally, we have examined how load-resource balance typically affects the final market price. Market price adjustment is generally insensitive to load-resource balance over a range that corresponds to the import-export limit of the system.

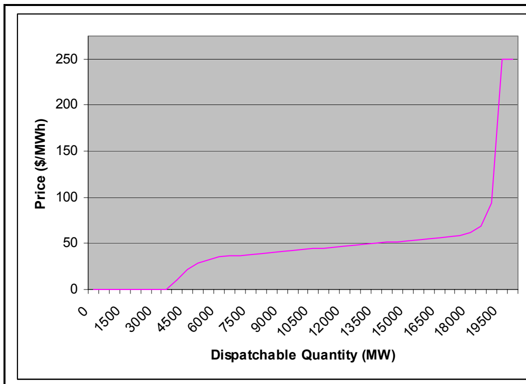



**Figure L-48: Average Price vs Average Load**

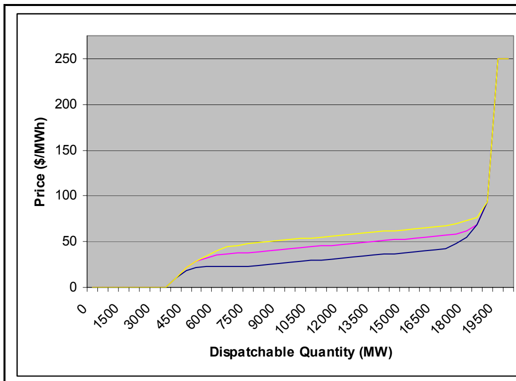



**Figure L-47: Alternative Average Prices**

This concludes the discussion of variables in quantities that depend only on the current period. Possible exceptions are supply curves for conservation. The amount of energy delivered in a given period can be, and typically is, a function of prices and activity in prior periods. The discussion of supply curves was included in this section nevertheless because the supply curves do not depend the history of a process. Processes such as the startup shutdown of aluminum smelters, on the other hand, depend in a direct fashion on how recently this smelter was shut down and whether it has been down for a significant amount of time. The functions and formulas that rely strongly on the nature of events over time are the subject of the next section.

## Multiple Periods

This section addresses processes that rely on memory of past circumstances. They respond not so much according to what is happening now as what has happened in the past. Load elasticity is one example. While the short-term correlation between load and electricity price is typically positive, over the long-term load will decrease if electricity prices remain high for a substantial amount of time. Other examples are the start-up and shutdown of aluminum smelters and the construction of power plants. In the latter case, it may be advantageous to postpone or cancel the construction of a power plant if it appears the plant will be unprofitable or unneeded. This section begins with a discussion of a concept that guides much of the modeling of these behaviors. It then describes how the portfolio model addresses the processes mentioned above.

### Concept Of Causality

In the description of the RRP algorithm (page L-51, above), there is a tacit assumption that generation is a continuous function of price. For example, what would the outcome have been if, in step five of Figure L-38, the increase in price had suddenly caused a smelter to shut down? Figure L-49 illustrates one possible outcome. With reduced load, the deficit after imports is reduced, which should make it possible to meet requirements with a lower market price for electricity. The illustration assumes that this affects both the lower price limit for surplus resources and upper price limit for deficit resources to roughly the same degree.

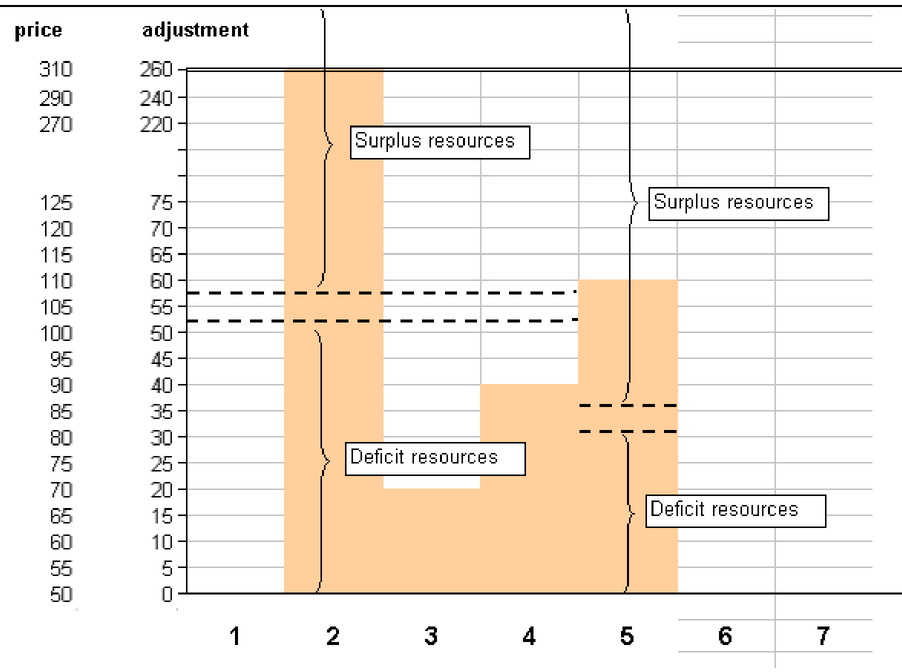



**Figure L-49: Discontinuous Load Response to Price**

Notice that the reduction in requirement is large enough that the price in step 4 is now too high to satisfy the balance constraints. The algorithm would not work, because there is no obvious way to determine what price would solve the problem, at least not by looking at price and deficit or surplus. In fact, the problem may be more serious than devising a smarter algorithm: there may *be no solution!* It can arise that no price would balance such a system.

To arrange for the iterative algorithm to solve the problem efficiently and avoid situations like this one, response of resources and loads to price must be stable and continuous. One way to assure this behavior is to remove such response from the current period, instead tying the response to past periods where prices have already been determined and fixed.

Thinking about how the primary sources of discontinuous response behave, this makes sense in terms of the accuracy of the model representation. For example, a smelter will not make start-up or shutdown commitments based strictly on current market prices. Instead, they will probably make some forecast about future conditions based on a trend that started at some point in the distant or recent past. It therefore is reasonable to assume that decision makers make such commitments at the beginning of a period and these remain fixed over the period.

This treatment of load or resource response in the portfolio model is an application of the "concept of causality." Actions in the past affect current circumstances, instead of having actions and circumstances occurring simultaneously. Wherever this approach is reasonable to use, it simplifies and speeds the iterative solution of the balance by removing a source of change and, as emphasized above, discontinuous change.

Conservation is an example of where the portfolio model employs a concept of causality, not because its response is discontinuous -- it is not -- but because it makes sense to do so and reduces computational burden. Pointing the supply curve's price to a decision criterion that depends only a on past period fixes the value of conservation in that period. The rather time-consuming computation of conservation takes place only once. Moreover, it makes sense that utilities would deploy conservation in this fashion, paying little or no attention to today's market prices but instead following budgets that may have been adopted the year before.

## Load

There are several components to load representation. There is an underlying trend, possible jumps associated with economic cycles, and a seasonal variance. Appendix P describes these. There is also a long-term sensitivity of loads to electricity price, which this section describes. The final calculation of energy and cost appear under the previous section, "Single Period."

Load elasticity changes once each year, because customers base their consumption habits more on annual average prices than seasonal costs. Additionally, retail customers are unlikely to see seasonal variation because of the ratemaking process. The load adjustment for electric price in {AQ321} points to the calculation in {AP321}, where the annual revision takes place. That calculation is

=(1+MAX(-0.002, MIN(0.002,-0.002*(AO225-$Q$224)/$Q$224)))

This formula limits load variation due to price elasticity to 0.2 percent. Some bounding of the elasticity provided better stability. That is, without bounding, the situation can arise where high prices depress loads, which in turn reduce prices, which increases load, and so forth.

The cell {$Q$224} contains the study's starting price for annual average electricity price. This is a cumulative change in load, up to the current period, due to changes in electricity since the beginning of the study.

Council Staff [**6**] chose the value of -0.002 as follows. They estimated an upper limit by starting with a five-year elasticity factor of -0.1 as appropriate for non-DSI loads, where electricity price is a retail rate. Because wholesale prices contribute about half to retail rate variation, an upper limit using wholesale electricity price is about -0.05. Using a single year's change warrants a value of perhaps -0.01. Finally, the stochastic treatment of load uncertainty captures much and perhaps most of the impact of independent influences on load, including some economic effects related to electricity price. A figure of -0.002 seemed an appropriate choice and provided realistic behavior.

## DSIs

Aluminum smelters have a cost structure heavily dependent on the price of electricity. With the increases in electricity price during the 2000-2001 energy crisis, the region saw 2000 MW of smelter load disappear. This constitutes 40% of the 5000 MW shift in the resource-load position the region has witnessed since 2001. Capturing the load uncertainty associated with direct service industries (DSIs) such as aluminum smelters is clearly important to the Council's treatment of risk.

Smelter load curtailment is distinct from dispatchable resources and demand response. Whereas dispatchable resources and demand response can curtail within hours, it requires months for a smelter to arrange for startup and shutdown. Although there is a portion of smelter load that can change with short notice, there are typically severe limitations on the amount and use of this load as a curtailment mechanism. Aluminum pot lines have significant thermal inertia, and several hours of interruption will not significantly affect production. However, extended shutdowns or repeated interruptions, without adequate preparation, can be disastrous.

In 1992, Council staff performed analysis of the profitability of each of the seven smelters in the region. Figure L-50 illustrates a typical calculation.

| | |
|---|---|
| Aluminum Price | 1550 |
| Premium Rate | 0.03 |
| BPA Rate | 23 |
| BPA Allocation | 100 |
| Mwh/Tonne | 13.199 |
| | Plant A (modern prebake) |
| Potential Demand | 457 |
| Cost Components | |
| Alumina | 403 |
| Carbon | 90 |
| Labor/Other | 400 |
| Sustaining Capital | 80 |
| Electricity Cost Max | 623.5 |
| Electricity Price Max | 47.24 |
| Electricity Price | $30 |
| Demand @ Price | 457 |

**Figure L-50: Cost structure of Aluminum Smelter**

Given the cost structure of the smelter, including the smelter's requirement for electricity, alumina, carbon, labor, and other fixed costs, and with the knowledge of aluminum price and the allocation and the price for any BPA power, a breakeven price for electricity can be determined. For each price of electricity, we can restate the total demand for all seven smelters as a function of aluminum prices. Figure L-51 illustrates supply curves for regional smelter load, given assumptions about the price of power available to the smelters.

In the portfolio model, we capture this response of smelter load to electricity price and aluminum price with a single UDF. This function tracks the response of each of the seven smelters separately, based on its unique cost structure. There are initial conditions provided for each smelter, representing the number of months that the smelter has been shutdown. If any smelter is shutdown for more than five years, it will be permanently retired. More details about these operations appear below.

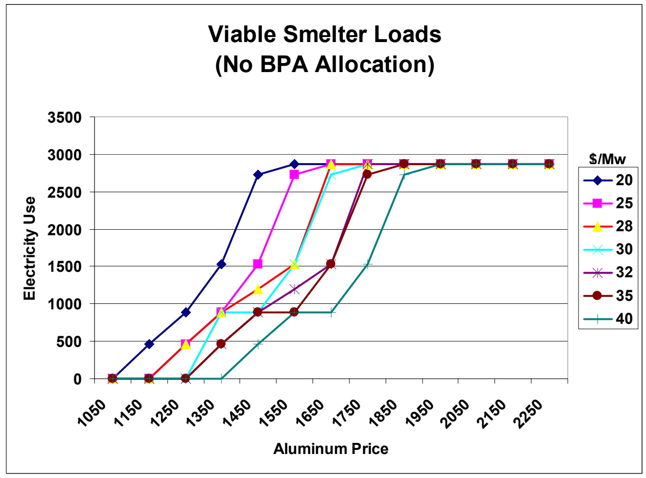



**Figure L-51: Supply Curves for Regional Smelters**

The model needs a criterion for determining whether a given plant should shutdown or restart. Figure L-52 illustrates a typical decision criterion for a smelter. Along the horizontal axis is time; along the vertical axis, the value of the decision criterion, denominated in arbitrary units. There is a horizontal line that determines whether the outlook for the smelter is favorable. We may think of the criterion as roughly the spread between aluminum electricity prices, although the reader will see shortly that the smelter-specific criterion is more detailed than this. The criterion starts out above zero, in positive territory, but soon becomes negative. The smelter enters an evaluation phase. During the evaluation phase, a decision maker would consider whether to shutdown the plant. If the decision criterion remains negative throughout the evaluation phase, the plant will be shutdown and remain down for a minimum amount of time. Later, when the criterion turns positives, the smelter enters

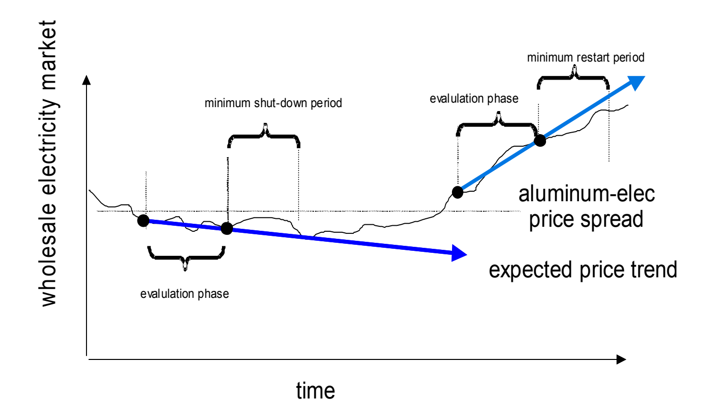



**Figure L-52: Decision Criterion for Smelter**

another evaluation phase. If the outlook for the smelter remains favorable throughout the evaluation phase, the smelter restarts. Once restarted, however, it must remain in service for a minimum amount of time. These minimum startup and shutdown times represent the time to adjust work schedules and contracts and to prepare equipment. Evaluation is ongoing during the minimum times.

The smelter-specific decision criterion *d* follows the profitability calculation in Figure L-50:

$$d = r - c \qquad (\$/\text{mT}), \text{ where}$$
$$r = p_A(1+\rho) \qquad (\text{revenue in } \$/\text{mT})$$
$$c = 0.26 p_A + c_f + p_e \alpha \quad (\text{cost in } \$/\text{mT})$$

and

$p_A$ is price of aluminum ($/mT)

$\rho$ is premium rate

$c_f$ is fixed cost of carbon, labor, capital ($/mT)

$p_e$ is price of electricity ($/MWh)

$\alpha$ is electricity intensity (MWh/mT)

The cost of alumina is $0.26p_A$. The decision criterion reflects any evaluation, so the plant operation will respond immediately to its value. Rearranging these terms, we have

$$d = p_A(1+\rho-0.26) - c_f - p_e\alpha$$

Whenever the criterion *d* turns from negative to positive, smelter operation continues or, if the smelter has been shutdown, restarts if minimum shutdown time is satisfied. When the criterion *d* turns from positive to negative, the smelter remains off-line or, if the smelter has been operating, shuts down if minimum in-service time is satisfied.

Turning to the workbook, we point out that, as opposed to all of the other UDF functions, some data hides in the UDF that calculates smelter capacity[22]. The portfolio model adopts this alternative to initializing the UDF from the worksheet because Council staff believes smelter parameters will not change significantly. If users wished to change some of these values, however, they are available in the VBA module containing the UDF code. Parameters that the user may specify are the following:

```
Const lNumberOfDSIPlants As Long = 7
Const dSmelterPricePremium As Double = 0.03
Const dAluminaCostFraction As Double = 0.26
Cosnt lNumPeriods as Long = 80

lDmd(0 To lNumberOfDSIPlants - 1)
```

[22] In range {F326:O327}, the reader will find values that appear to be parameters for the smelter UDF. This is a vestige of an older UDF. They should have been cleaned out. The model does not use these values.

dMWhPerTonne(0 To lNumberOfDSIPlants - 1)
dNonPowerCostPerTonne(0 To lNumberOfDSIPlants - 1)
dDiscountPowerPrice(0 To lNumberOfDSIPlants - 1)
dDiscountPowerAmt(0 To lNumberOfDSIPlants - 1)
lNumPersDown(0 To lNumberOfDSIPlants - 1)
lNumPersUp(0 To lNumberOfDSIPlants - 1)
lMinNumUpTimePers(0 To lNumberOfDSIPlants - 1)
lMinNumDownTimePers(0 To lNumberOfDSIPlants - 1)
dUpThreshold(0 To lNumberOfDSIPlants - 1)
dDownThreshold(0 To lNumberOfDSIPlants - 1)
lInitialPeriodsDown(0 To lNumberOfDSIPlants - 1)
lPeriodsDownBeforeShutdown(0 To lNumberOfDSIPlants - 1)

Because of the proprietary nature of some of this information, we do not provide smelter-specific values in this documentation. Most of the parameters in the list above should be self-explanatory. The parameters dUpThreshold and dDownThreshold permit users to specify thresholds above or below zero for the decision criteria on a plant specific basis. The parameter lPeriodsDownBeforeShutdown specifies how many periods of negative decision criteria values to permit before permanently shutting down the smelter.

The electricity price that the decision criterion uses may be a melded price, reflecting not only market price but also some subsidized power. The Wenachee smelter, for example, gets 40% of its power from Chelan PUD at a discount from market, and the portfolio model reflects that fact. The UDF that computes smelter load assumes that the smelter either operates at full capacity or does not operate at all. For this reason, decisions are made based on the melded price of electricity, not on the prices of each source of electricity. With this assumption, the user stipulates any discounts through the values of dDiscountPowerAmt and dDiscountPowerPrice. The definition of dDiscountPowerPrice, however, is idiosyncratic. We can express electricity price generally as:

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n} + p_m \times MWh_m}{MWh_{s_1} + \cdots + MWh_{s_n} + MWh_m}$$

where

$p_{s_i}$ is the price of discounted power from source $i, i = 1...n$

$MWh_{s_1}$ is the amount of discounted power from source $i, i = 1...n$

$p_m$ is the market price

$MWh_m$ is the market amount

Let $S$ denote the total amount of discounted power and $D$ denote the total demand.

$$S = MWh_{s_1} + \cdots + MWh_{s_n}$$
$$D = S + MWh_m$$

Because the denominator is just the total amount of demand D for the smelter, we have

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n}}{D} \; + \; p_m \times \frac{(D-S)}{D}$$

Now, the first term is entirely fixed. One can think of it as the weighted price of power,



if the price of market power were zero. This is the definition of dDiscountPowerPrice. The convenience of this definition is that if dDiscountPowerPrice and dDiscountPowerAmt ($S$) are zero, then $p_e = p_m$. Moreover, if discounted power comes in various amounts from various sources, these two variables alone still capture the total effect.

In the workbook, we find in cell AQ 327 the following formula

=lfDSICol(AP$227, AP$270, AP$46,2, AP327)

The UDF lfDSICol returns the value for the total smelter load in the region. The definition of this function is as follows

```
Function lfDSICol(ByVal sPowerPrice As Single, ByVal sAluminumPrice As Single, _
   ByVal lPeriod As Long, ByVal lSide As Long, ByVal dummy As Long) As Long

Takes:
sPowerPrice       - Electricity Price ($/MWh)
sAlumPrice        - Aluminum Price ($/metric tonne)
lPeriod  - period for which the calculation applies.  Note that to stabilize calculation, we are
           pointing to the period _preceding_ the period in which the function is called, consistent
           with the principle of causality
lSide    = 0 for east, 1 for west, 2 for both

Returns:
           Total smelter load (MW) as Long
```

The first two parameters point to the 18-month averages for electricity aluminum price in rows 227 and 270, respectively. Taking the average over an extended period in the recent past provides both inertia to the decision and a reasonable evaluation period. As discussed later in the section "Decision Criteria," these prices are proxies for forward prices. The UDF uses the flat price for electricity, the average of on and off peak electricity.

The third parameter merely tells the UDF for which period it is computing a value. The fourth parameter, which has the fixed value 2, specifies that the UDF return the sum of the loads for Eastern and Western smelters. If the user chose to employ this UDF in a different application, he or she could select loads for just those smelters in one subregion. The final parameter is merely a dummy that forces calculation of the previous period's UDF before execution of this period's UDF.

The formula in cell AQ328 computes the energy requirement in megawatt hours.

=1152*$AQ$327

This is merely the energy in average megawatts times the number of hours on peak. The cost in millions of dollars is computed in AQ329.

=AQ328*$AQ$204/1000000

Because we assume no correlation between energy prices and this load, the cost of this load is merely the product of the load and the price divided by one million. The off-peak calculation is identical.

One option that a user should consider if he or she wants to implement this UDF in their own application is that this is a specific application with potential generalization to other industries. That is, the modeling of any other industry that relies heavily on electricity, such as petrochemicals or paper refining, can make use of this UDF. Instead of the spread between aluminum prices and electricity prices, one would consider the spread between paper prices and electricity prices, for example. Indeed, the spread between the costs of any two commodities or any predictor of loads could provide a general decision criterion, although the user would obviously have to modify the UDF somewhat.

Finally, there is a utility available that permits users to view the status of each smelter for a particular future. This utility, a separate UDF, is not available in the portfolio model but is upon request.

In summary, the DSI UDF permits the portfolio model to quickly calculate total smelter load in the region based on each smelter's profitability, as determined by the prices for aluminum and electricity. It provides an idea of the long-term load response of these industries, as opposed to the short-term response captured through, for example, demand response. The UDF accommodates user-specified assumptions through VBA constants in the code, including those regarding discounted power. Although tailored to the aluminum production industry, the concepts and much of the code in this UDF are applicable to other industries as well.

## New Resources, Capital Costs, and Planning Flexibility

Certain aspects of resources permit a decision maker to respond to changing circumstances quickly or inexpensively. Collectively, we refer to this as planning flexibility. Sources of planning flexibility include:

- Modularity (small size) permits a more exact match to requirements and reduces fixed-cost risk.
- Short lead-time facilitates rapid response to opportunities or unexpected requirements.
- Cost-effective deferral or cancellation is usually available only for a limited time during the construction cycle. The decision maker values the ability to change his or her mind without incurring excessive cost.

The value of flexibility played a key role in the 2000-2001 energy crisis. The region saw load management and conservation respond to changing circumstances much faster and more effectively than conventional thermal supply-side resources.

Valuing this source of flexibility is nothing new to the Council. Planning flexibility was explicitly valued in 1991 plan with the ISAAC model. However, ISAAC used load projections to decide when to add resources, instead of using market value like the portfolio model.

The discussion in this section focuses on the third source of planning flexibility listed above, cost-effective deferral or cancellation. The portfolio model captures the value of the other sources of planning flexibility, but valuing cost-effective deferral or cancellation requires special spreadsheet logic. This section describes how the portfolio model achieves this objective with a special UDF.

Although capturing planning flexibility has been a primary objective in the design of this special UDF, the UDF also performs the important function of computing capital and fixed costs for new resources. The discussion of valuation costing that begins on page L-13 addresses variable costs. The fixed costs of existing resources do not bear on any decisions in the regional model, but total system costs still require computing fixed and capital costs for additions. That latter task belongs to this special UDF.

Cost-effective deferral or cancellation of power plants depends on the construction cycle. Cash flow, in turn, provides an important perspective on the construction cycle. A typical cash flow pattern appears in Figure L-53. Cash flow determines natural decision points. For the first 18 months in the example illustrated in Figure L-53, only siting and permitting take place. Siting and permitting are inexpensive activities. The decision maker incurs relatively little expense if he or she interrupts or cancels the power plant during this phase. After completion of siting and permitting, however, construction begins, which typically requires a substantial initial investment. The project breaks ground on administrative buildings and substations. The owner may need to make deposits on some of the most expensive equipment, such as turbines or boilers. After some period of construction, nine months in our example, the project reaches a final decision point. If the project is to proceed, the owner must take delivery of and pay for the most expensive pieces of equipment. Beyond this point, the owner will complete construction, because most of the costs are effectively sunk. The owner presumably completes the plant and brings it online.

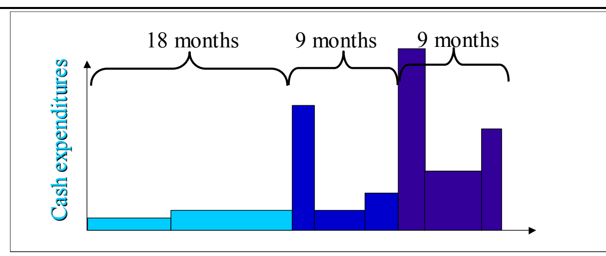


**Figure L-53: Partitioning the Construction Cycle**

As in the case of aluminum smelters, the portfolio model uses a decision criterion to determine whether to proceed through each phase of construction. The regional portfolio model assumes, however, that the first phase of siting and licensing is completed.[23] The details of the decision criterion are below, but it functions in a manner identical to that for DSIs. Given that siting and permitting is complete for a specific resource in a given plant, the decision criteria will immediately determine whether to proceed with the optional phase of construction. At any point during the optional phase of construction, the model may defer or cancel construction if the criterion turns negative. If the model defers construction ("mothballs" the plant) and construction does not resume within a number of periods specified by the user, construction terminates and the project incurs cancellation costs. During deferral, the plant accrues mothball costs instead of construction costs. Once the requisite time and cost for optional construction finishes, committed construction begins and continues until the plant goes online. Figure L-54 illustrates the decision criterion in a manner similar to Figure L-52, and Figure L-55 illustrates the effect that an adverse decision criterion value in periods five through nine would have on three plants started on a staggered schedule. The negative criterion value affects only the last plant, initiating the third period, because the criterion acquires a negative value after the planning period and before the committed construction period.

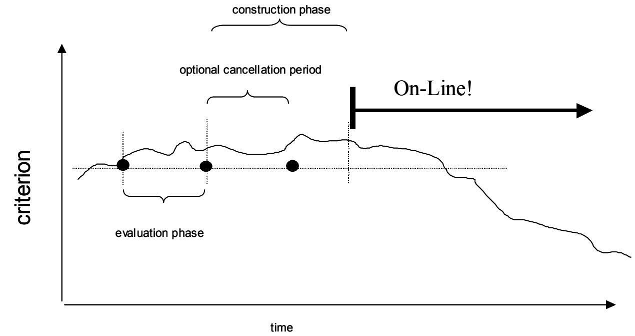


**Figure L-54: Decision Criterion and Phases**

As Figure L-55 implies, there are cohorts of plants available for planning or construction commencement in each period of the study. Each cohort has identical cost and operational characteristics. The UDF returns the cumulative capacity and total cost across all cohorts. Although the UDF makes cohorts available in each period, the user controls their size and availability by specifying a particular plan, so size and availability typically vary from period to period. The description of how to control the size and

[23] Here the fiction of a 20-year resource plan asserts itself. Although required by statute, the Council understands that a fixed blueprint for resource additions 15 years in the future, even the inexpensive siting and licensing process, is unrealistic. The purpose of the 20-year plan instead is to assure that the necessary commitments made in the Action plan do not preclude future opportunities or burden future generations in the region with imprudent, long-term obligations. Without specific future commitments, however, how does the region obtain a clear idea of the relationship of current decisions, made in the Action Plan, and future actions that might be precluded or required? For example, if the Action Plan tacitly relies on wind in the next decade, although it may not call for it in the next five years, how would the region know when to build long-lead time transmission now? Clearly, this requires a specific long-term resource plan. A fixed plan of construction, however, does not permit valuation of flexibility. The approach of the regional portfolio model is to commit to specific construction preliminaries, to the siting and licensing for specific amounts of specific technologies at specific points in the future. The Council believes this approach balances the need for specificity with the valuation of flexibility.

presence of each cohort through "decision cells" appears in the section "Parameters Describing the Plan" on page L-72.

If the user stipulates, the UDF that performs the function of tracking construction for cohorts of power plants is capable of adding plants *whenever* the decision criterion is positive. The intended application for this feature is modeling the market-driven addition of power plants. Using this feature, the user can specify that construction costs are different depending on whether power plants are planned for or are added when market conditions are favorable. Recent history shows that when market conditions are attractive, the demand for power plants and their components increases, as does the associated cost. The regional portfolio model, however, does not implement this feature. Instead, the optimizer controls all additions. The optimizer selects the timing, sizing, and choice of technology to find an optimal plan given risk constraints.

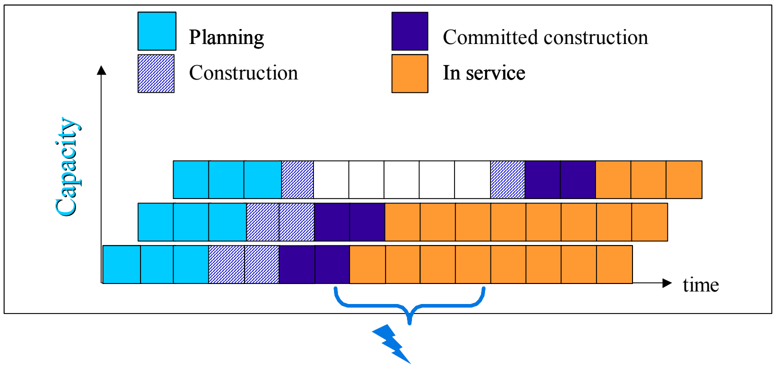



**Figure L-55: Effect of Decision Criterion on Cohorts**

The UDF can also provide for special cash flow features that the regional model *does* incorporate. First, it can capture sunk costs associated with a plan, specifically the sunk costs for planning, siting, and licensing. This takes place despite there being no planning periods per se with which to associate those sunk costs. Instead, the sunk costs merely add to subsequent levelized costs. Second, the UDF can represent the situation where the first period of optional construction incurs the total cash flow associated with that phase of construction. This type of cash flow pattern is a "pulse." Ordinarily, levelized cash flow rates increase in steps of constant size over periods when there is construction activity. The regional model uses pulse cash flow instead to better reflect the jump in cash flow at the beginning of the optional phase of construction, as illustrated in Figure L-53. Council staff felt the difference in cash flow patterns might affect valuation decisions.

The UDF also easily accommodates capacity expansion *without* planning flexibility, if the user wishes to either "hard-wire" new capacity or have an optimizer do so. The user assigns the cells containing the decision criterion a constant positive value. The Crystal Ball "decision" cells, described below, then control all additions directly.[24]

The scenarios in Chapter 7 of the plan illustrate the response of a plan to changing circumstances. These scenarios demonstrate, among other things, how this UDF controls

[24] There must be at least one planning or construction period, however.

the construction and completion of power plants. To the extent these changes are responsive and inexpensive, they add to the value of a plan.

In the workbook, three worksheet ranges control the performance of capacity additions and costing. The first are the parameters describing each technology. These values represent such things as capital cost, and they do not change unless the user changes the description of a plant. The second are the Crystal Ball decision cells, which the optimizer controls. These specify the timing, size, and type of technology, and their values specify the plan. The third are the period calculations, the values of which typically change under each future. This section will discuss each of these in turn.

### Parameters Describing Each Technology

The worksheet cells that control the characteristics of any new capacity appear in the range {B454: P519}. The cells that control the characteristics for the generic combined-cycle combustion turbine (CCCT) units appear in Figure L-56. Identical sets of parameters, obviously with different values, exist for single cycle combustion turbines (SCCT), coal plants, wind plants, and optionally demand response and coal tar processing CCCTs in Alberta.

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 453 | | | | | | | | | | | | | | | | |
| 454 | | Criterion_S | Planning_P | Optional_C | Committed | Planning_C | Mothball_C | Cancellatio | Constructic | CancelThre | Const Cost | ResourceLi | OptionLife ( | PermitMark | PlannedPla | Index |
| 455 | | CCCT Crite | 0 | 4 | 4 | 0 | 0.000292 | 0.0116796 | 0.0029199 | -99999 | -0.086% | 80 | 20 | FALSE | 0.001491 | 0 |
| 456 | | | | | | | | | | | | | | | | |

**Figure L-56: New Capacity Parameters**

Before we proceed with the description of each of the parameters appearing in this range, it may be useful to explain several conventions. First, the units of time are periods, as defined for the portfolio model. The regional model uses the hydro-year quarter. The escalation rates for capital costs are also expressed in rate of change per period. Second, all cost rates are denominated in real levelized millions of dollars per megawatt per period squared. The determination of this value is according to the following equation:

$$\frac{\text{RL \$M}}{MW \bullet per^2} = \frac{RL\$}{kWyr} \bullet \frac{yr}{per} \bullet \frac{1}{\# \, per} \bullet \frac{kW}{MW} \bullet \frac{\$\text{M}}{\$} \qquad (5)$$

This appendix has already discussed the reasons for using real levelized dollars. The reason for expressing cost rates in terms of dollars per period per period (or equivalently, dollars per period squared) is that construction can halt during the earlier



construction phase. It is therefore necessary to stipulate the *rate* at which period construction costs accumulate. Another subtlety here is that this model uses standard months and standard years for variable cost calculations. (See discussion on page L-11.) To make sure that variable and fixed costs are consistent, the model uses fixed costs in dollars per kilowatt-***standard*** year, rather than the more conventional dollars per kilowatt-year. Thus, the second term on the right-hand side of equation (5) has a value of about 0.23, which derives from the following equation:

yr/per = (std mo per std qtr)(wks per std mo)(days per wk)(hours per day)/(hours per year)
= (3)(4)(7)(24)/(8760)

The third term on the right-hand side of equation (5) is simply the reciprocal of the number of periods in the phase of construction. In the example that appears in Figure L-56, this term would have a value 1/4 for the phase associated with committed construction.

So, for example, assume a CCCT with total fixed cost, including fixed fuel and transportation but excluding planning costs, of $101.50/kWyr. This real levelized cost is in 2004 dollars, ignoring escalation. If construction requires eight hydro quarters (two years), the equivalent cost rate from equation (5) would be

$$0.0029181 = (101.50)(0.23)(1/8)(1000)(1/1000000)$$

which corresponds to the construction cost rate in column I of Figure L-56.

The only exception to this characterization of costs is for the treatment of sunk costs, described above. If the numbers of periods for the planning phase in column C is zero, and non-zero "planned planning" costs appear in column O, the UDF assumes sunk costs. In this special case, the cost rate in column O applies.

With this background, consider the entries in the columns of Figure L-56:

- Column B has a name that specifies which planning flexibility record Olivia used to create this description. (The description of Olivia appears in the section "Olivia" starting on page L-136.) The value in this column has no meaning otherwise in the portfolio model.

- Columns C through E indicate the number of periods in the planning, optional construction, and committed construction periods, respectively. For example, optional construction lasts four periods, which correspond to one year because the periods in the regional model consists of hydro quarters. The number of planning periods in all of these capacity expansion options are zero, because the model assumes planning is complete and planning costs are sunk, as described above.

- Columns F through I contain the cost rates associated with the various phases of planning and construction. During each period of these phases, the plant cost accumulates R x C x $(1+E)^P$ millions of dollars, where R is the relevant cost rate, C is the plant capacity in megawatts, E is the escalation factor in column K, and P is the number of periods since the beginning of the study. Cancellation, if it occurs, happens in one period. Like all other costs, however, cancellation costs contribute to subsequent periods for the duration of the life of the plant, stipulated in column L.

The cost rate in column F is always the cost associated with unplanned construction, driven by market conditions. The model implements the use of unplanned construction in response to market conditions only when the user sets the value in column N is TRUE *and* there is no cohort planned for the period. Otherwise, the model uses the planning cost rate in column O. (See the discussion of choices for columns N and O, below.) The regional model does not use unplanned construction in response to market conditions, and the value in this column is zero for all new capacity candidates.

- Column J has the value of the cancellation threshold. If the decision criterion falls below this value, the plant cohort will cancel immediately and will incur the cancellation penalty. None of the plants in the regional model use this option; the value of the cancellation threshold is instead set arbitrarily low.

- Column K identifies the escalation rate for capital costs, including the capitalized planning and construction costs. The rate is per portfolio model period. For example, if the annual rate of increase is negative 0.3423 percent per year and the period is a hydro quarter, as in the case of the regional portfolio model, then the period escalation rate is $-0.00085682 = (1- 0.003423)^{1/4}-1.0$. Note that conversion from conventional years to standard years is neither necessary nor appropriate. Although the numbers of hours in each are different, standard years represent conventional years. That is, costs four standard quarters later will be five percent higher, too.

- Column L specifies the resource life in periods. In the regional model, 80 periods is 20 years. The model distributes all real levelized costs according to the resource life. The associated real levelized cost contributes to the total real levelized cost when the event (planning, construction, cancellation) occurs, disappears from the total after the resource life's number of periods, and applies to all intervening periods. Note that this implies the cost contribution typically begins and ends in periods other than the on-line date or retirement period of the plant.

- Column M has the maximum number of periods that the model will hold the plant in its mothballed state before canceling the plant. Its value is arbitrary, and setting the value higher than the number of study periods effectively turns off this option.

- If the user wishes the model to start a plant cohort in any period where the decision criterion is positive, they indicate so by setting to TRUE the value in column N. In this case, the model would interpret values that otherwise would determine the plan as capacity ramp rates. Each cohort, if completed, would contribute the capacity specified by the ramp rate. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") The calculation of planning costs also depends on the value in this column, as explained in the next bullet.

- How the model interprets the value in column O depends on the value of column C, the number of planning periods. If the number of planning periods is zero, the cost rate in column O is that for the sunk cost associated with planning incurred before construction begins. As for all cost rates, these are denominated in real levelized millions of dollars per megawatt per period squared, although the UDF assumes only one period for sunk costs. In the example appearing in Figure L-56, the value is .001491. The costs incurred quarterly due to sunk planning and siting is the product of the unit capacity, 610 MW, times this value, times the escalation factor, or about $910,000 per quarter. All new plants in the regional model use the convention of sunk planning and siting cost.

  If on the other hand the value in column C, the number of planning periods, is greater than zero, then the determination of the planning cost rate hangs on the value of the market addition flag in column N. If the market addition flag is FALSE, the cost rate in column O applies to each planning period, as in the description of costs in columns F through I, above. If the market addition flag is TRUE, then the cost rate in column O applies to each planning period only if there is a non-zero entry in the decision cell for the cohort. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") Otherwise, the cost rate in column F applies to each planning period. Presumably, the cost rate in column F would be higher than that in column O, reflecting higher costs of not planning for capacity additions. Although the higher costs are associated with planning in the portfolio model, they certainly may represent the total of higher costs due to both planning and construction.

One additional controlling parameter unfortunately does not appear here. The switch that determines whether costs in the optional phase of construction are "pulsed," as in the regional model, or applied as construction proceeds is at the top of the VBA code module "mod_PlanningFlex"

```
Private Const bTrigger As Boolean = True 'determines whether all construction costs _
    for optional construction are incurred at the beginning of construction
```

Council staff added this parameter and capability late in the modeling process, and they never completed the proper establishment in the worksheet interface.

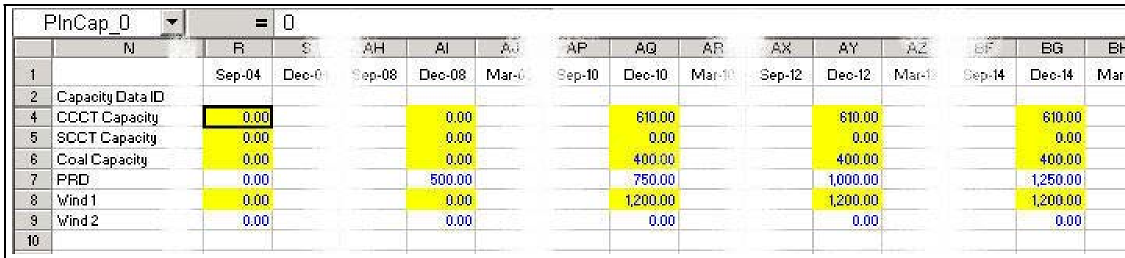
These parameters and values may be initially confusing. Once set, however, the user typically would have little need to modify them, except perhaps to update construction costs. A numerical example of how the model interprets these parameters to arrive at final costs appears below in the section "Period Calculations" beginning on page L-74.

### Parameters Describing the Plan

A plan is defined by the timing, size, and choice of technology for new resources. As explained in the previous section, the timing of new resources in the regional model is, more precisely, the earliest date of new construction. The resource's production of electricity may occur as early as the planners' scheduled completion of construction or much later or not at all, depending on circumstances.

In the worksheet, the range {R3:CS9} determines the plan. A simplified view of this range appears in Figure L-57. This range of cells contains special cells that are under the direct control of Decisioneering's Crystal Ball and OptQuest. Decisioneering Inc. refers to these as "decision cells." OptQuest is the Excel add-in performs stochastic, nonlinear optimization. During the process of seeking a Least-Cost, Risk-Constrained plan, OptQuest modifies the values of these decision cells. The decision cells in Figure L-57 are yellow, the default color for decision cells under Crystal Ball.

In the regional model, potential capacity additions occur according to an irregular schedule. The first opportunity for construction is in September 2003 (column R).[25] The next opportunity is December of calendar year 2007. After this, opportunities fall every two years through December of calendar year 2019.



PlnCap_0 = 0

| | N | R | S | AH | AI | AJ | AP | AQ | AR | AX | AY | AZ | BF | BG | BH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Sep-04 | Dec-0 | Sep-08 | Dec-08 | Mar-0 | Sep-10 | Dec-10 | Mar-10 | Sep-12 | Dec-12 | Mar-1 | Sep-14 | Dec-14 | Mar- |
| 2 | Capacity Data ID | | | | | | | | | | | | | | |
| 4 | CCCT Capacity | 0.00 | | | 0.00 | | | 610.00 | | | 610.00 | | | 610.00 | |
| 5 | SCCT Capacity | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 6 | Coal Capacity | 0.00 | | | 0.00 | | | 400.00 | | | 400.00 | | | 400.00 | |
| 7 | PRD | 0.00 | | | 500.00 | | | 750.00 | | | 1,000.00 | | | 1,250.00 | |
| 8 | Wind 1 | 0.00 | | | 0.00 | | | 1,200.00 | | | 1,200.00 | | | 1,200.00 | |
| 9 | Wind 2 | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 10 | | | | | | | | | | | | | | | |

**Figure L-57: New Capacity Decision Cells**

These dates are a bit arbitrary. Construction typically begins in December, because December is the closest to the beginning of a calendar year, a convenient milestone for describing a plan. Occasionally, utilities will attempt to complete construction before the end of a year for tax purposes, as well. It is crucial that the portfolio model use as few construction dates as possible. Increasing the number of choices for start dates and for increments of capacity additions can dramatically increase the number of possible plans. Indeed, with the rather conservative choice present in the regional model, the number of possible plans still exceeds $10^{24}$. This is the key reason optimization is useful in identifying least-cost plans. Early in the study process, it became apparent that the model constructs few resources in the first 10 years, largely due to a surplus of existing resources in that period. It made sense therefore to sample the second decade of the study period more carefully than the first decade. These considerations led to the pattern of earliest construction dates that appear in the final regional model.

The previous section described how there are cohorts of a given plant technology available in each period of the study. The user, however, must make a given cohort available by assigning a nonzero capacity to the period in which the cohort originates.

[25]The header label in Figure L-57 and in the model says "September 04" because the regional model uses hydro years. The regional model deems September through August of the following year a hydro year or streamflow year. The calendar year in which it ends, in this case 2004, designates the hydro year.

There is an Excel range name in column R of each row corresponding to a new resource. (See for example the range name **PlnCap_0** in cell {R 4} of Figure L-57.) At the beginning of a Monte Carlo run for a given plan, the workbook finds this range and reads the associated row of values to determine which cells are blank and to obtain the values from nonblank cells.

How the model interprets the values in each row depends on whether the user has specified that additions are market-driven. (See discussion of columns N and O in the previous section.) In the regional model, additions are *not* market driven. If additions are not market driven, nonblank entries represent cumulative megawatts of the resource from that period forward until the next nonblank entry. The model permits only cohorts that start in the nonblank period *and* only if the value in the period increases from the previous nonblank value. This means that if the decision criterion is negative in that period, then cohort never begins construction.[26] Consider the situation for CCCT in Figure L-57. The cumulative capacity in December hydro year 2010 and December of hydro year 2012 are both 610 MW. This means that the model can add 610 MW in hydro year 2010, but it cannot add more capacity in hydro year 2012. It is the change in cumulative capacity that enables potential new construction.

If, instead, the user specifies that additions *are* market-driven, nonblank entries represent incremental megawatts possible in that period. The same ramp rate applies to all futures periods, unless there is a nonblank entry that changes this ramp rate. When additions are market driven, the cohort of the given technology will become active in any period where there is a positive value for the decision criterion. The prevailing ramp rate in a given period determines the amount of capacity that the model will add. Whether a non-blank entry specifies the ramp rate or the ramp rate is inherited from an earlier period *does* affect planning costs. If there is a nonblank incremental capacity entry, lower planning costs are available in the portfolio model, as described in the previous section. Otherwise, the model will use higher cost for planning.

### Period Calculations

The third and final area of the worksheet that controls the capacity addition and costing are the period's cells. These cells contain the functions that return the capacity and cost. Cell {AQ455} contains the following formula, which returns the total capacity across all cohorts for the generic CCCT unit:

```
=lfPFCap(AQ$302,AQ$46,$P455)
```

The definition for this UDF is as follows

[26] Of course if they were nonblank entries in the subsequent period, the technology would "get another chance." This is not the case in the regional model, however, where options for the beginning of construction occur only once every two years.

```
Function: lfPFCap(ByVal dCriterion As Double, ByVal lPeriod As Long, _
          ByVal lPlant As Long) As Long
Takes:
          dCriterion  - Prices or criteria values that would indicate success moving forward
          lPeriod     - 0-based index to period for which the calculation pertains
          lPlant      - 0-based index to plant for which computation pertains

Returns:   A long with the number of MW
```

All of the necessary information regarding the technology and the plan are available in memory arrays to the special UDF lfPFCap. Based on this information and the value of the decision criterion, the UDF determines the appropriate amount of capacity to add, according to the rules described earlier. The UDF updates the real levelized costs at the same time. There are identical formulas for generic coal plants, wind plants, and the other new resources in other periods. Each generic technology, of course, points to its own decision criterion and plant index.

The second special UDF, sfPFCost, then retrieves the period real levelized costs totaled across all cohorts for this technology.

=sfPFCost(AQ455,AQ$46,$P455)

The definition of the special UDF is as follows

```
Function sfPFCost(ByVal lDummy As Long, ByVal lPeriod As Long,
          ByVal lPlant As Long) As Single
Purpose:
          This function is a companion to lfPFCap.  It reads the cost matrices and
          returns the appropriate period's information

Takes:
  lDummy    - Forces calculation of lPFCap
  lPeriod   - 0-based index to period for which the calculation pertains
  lPlant    - 0-based index to plant to which computation pertains

Returns:
  The real dollar amount ($M) for the period, after escalation, but before discounting
```

Up to this point, this section has discussed the use of the capacity expansion and planning flexibility logic in detail but has not provided an example of how all these pieces fit together. To see how the model interprets the parameters and values presented above, consider Figure L-58. This illustration features two special UDFs that facilitate viewing the model's internal workings. The UDF "lfPFCohortStatus" returns the status of a given cohort for each period in the study; the UDF "sfPFCohortCost" returns the period cost for that cohort. Because the results returned by the "lfPFCap" and "sfPFCost" are aggregate capacity and period cost across all cohorts of a given technology, it is useful for diagnostic and training purposes to have UDFs that permit an analyst to study the workings of one cohort in isolation.

These UDFs are available in the portfolio model, but the only range in the regional model that refers to them is {R463:CS464}. In the model, placing an "m" before the equal sign in their formulas has deactivated them. The “m” forces Excel to interpret the formulas as strings. In Figure L-58, removing the “m” reactivated them, and pointing the parameters to updated cells eliminated some bad initial references. The VBA code module “mod_PlanningFlex” defines and recommends how to use the status UDFs, so this appendix will provide no further explanation.

The cursor in Figure L-58 is on cell {AQ464}, and the formula in that cell appears in the equation window at the top of the figure. Formula auditing is on, revealing that the parameters of the UDF point to the cohort index, to the period, to the plant index, and to the previous cell. The reference to the previous cell, as elsewhere, forces the calculation order by guaranteeing the worksheet updates the previous formula before the subject cell. Other instances of this formula in row {464} have identical parameter formulas but of course point to different period columns and different previous cells.

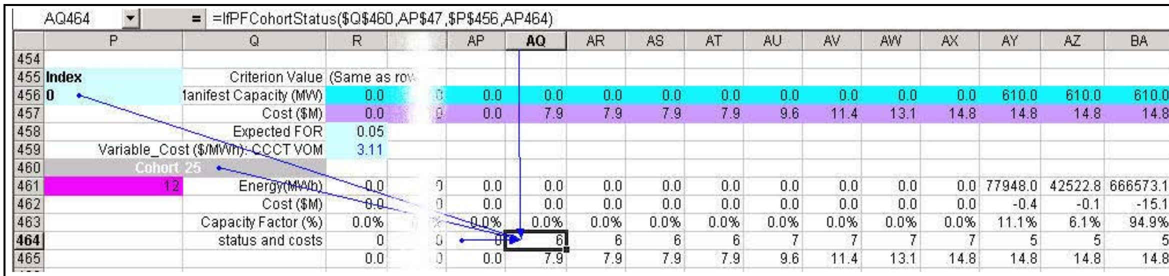



**Figure L-58: Status Functions**

In Figure L-58, the UDF lfPFCohortStatus returns the value 0 in row {464} up to column {AQ}. In columns {AQ:AT}, the value is 6; in columns {AU:AX}, the value is 7; and in columns to the right of {AX}, the value is 5. These values represent the status of cohort 25, plant 0 (the CCCT) in each period. Cohort 25 is the cohort that begins in period 25, the period in column {AQ}. The following table defines the meaning of the status codes:

lUnderConsideration As Long = 0
lNeverStarted As Long = 1
lPlanned As Long = 2
lMothballed As Long = 3
lCancelled As Long = 4
lCompleted As Long = 5
lOptionProceed As Long = 6
lConstrProceed As Long = 7
lRetired As Long = 8

The next row contains instances of the UDF sfPFCohortCost, which return costs for cohort 25 only. *With this information and the value of the decision criterion in each period, the user has the means to verify the calculations determining capacity addition and costs in each period.*

Start with the description of the construction cycle of the CCCT, including the percentage of costs and amount of time spent in each of the construction phases:

| name | | Siting and Permitting | Optional Construction | Commited Construction | Totals |
|---|---|---|---|---|---|
| CCCT | Periods to complete phase (quarters) | 8 | 4 | 4 | 16 |
| CCCT | Periods to complete phase (months) | 24 | 12 | 12 | 48 |
| CCCT | Cost to complete phase (Overnight, MM 2000$) | 20 | 66 | 234 | 320 |
| CCCT | Cost to complete phase (Overnight, 2000$/kW) | 33 | 108 | 384 | 525 |
| CCCT | Cost to complete phase (% Overnight) | 6% | 21% | 73% | 100% |

**Figure L-59: CCCT Construction Cycle**

In Figure L-56, the specification of periods for optional and committed construction is evidently consistent with Figure L-59. The next step is to determine the cost and cost escalation rates for planning and construction. Figure L-60 identifies the real levelized costs for generic CCCT plant started in each year listed in column A. The capital cost in column T includes planning costs. The calculation adds fixed O&M and fixed fuel costs to arrive at a total fixed real levelized cost for each generation of generic CCCTs. From this calculation, we take away two numbers, the 2004 levelized cost in cell Z38 and the quarterly cost escalation rate in cell Z62. This quarterly escalation rate calculation is on page L-71; it matches the escalation rate in Figure L-56.

Z40 = =W40+U40+T40

| | A | T | U | V | W | X | Y | Z |
|---|---|---|---|---|---|---|---|---|
| 32 | Levelized costs by service year (2004$): | | | | | | | |
| 33 | | | | | | | | |
| 34 | | Capital (2004$) | Operation (2004$) | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | | | | |
| 37 | Service Year | ($/kW/yr) | Fixed O&M ($/kW/yr) | Variable O&M ($/MWh) | Fixed Fuel ($/kW/yr) | Variable Fuel ($/MWh) | | Total fixed for portfolio |
| 38 | 2004 | $53.77 | $29 | $3.11 | $25 | $25 | | $108 |
| 39 | 2005 | $53.56 | $29 | $3.11 | $26 | $24 | | $108 |
| 40 | 2006 | $53.34 | $29 | $3.11 | $26 | $24 | | $108 |
| 41 | 2007 | $53.13 | $29 | $3.11 | $26 | $24 | | $107 |
| 42 | 2008 | $52.92 | $28 | $3.11 | $26 | $24 | | $107 |
| 43 | 2009 | $52.71 | $28 | $3.11 | $26 | $24 | | $107 |
| 44 | 2010 | $52.50 | $28 | $3.11 | $25 | $24 | | $106 |
| 45 | 2011 | $52.29 | $28 | $3.11 | $25 | $24 | | $106 |
| 46 | 2012 | $52.08 | $28 | $3.11 | $25 | $24 | | $106 |
| 47 | 2013 | $51.87 | $28 | $3.11 | $25 | $24 | | $105 |
| 48 | 2014 | $51.67 | $28 | $3.11 | $25 | $24 | | $105 |
| 49 | 2015 | $51.46 | $28 | $3.11 | $25 | $24 | | $104 |
| 50 | 2016 | $51.25 | $28 | $3.11 | $25 | $24 | | $104 |
| 51 | 2017 | $51.05 | $28 | $3.11 | $25 | $24 | | $104 |
| 52 | 2018 | $50.85 | $28 | $3.11 | $25 | $24 | | $103 |
| 53 | 2019 | $50.64 | $28 | $3.11 | $24 | $24 | | $103 |
| 54 | 2020 | $50.44 | $28 | $3.11 | $24 | $23 | | $102 |
| 55 | 2021 | $50.24 | $28 | $3.11 | $24 | $23 | | $102 |
| 56 | 2022 | $50.04 | $28 | $3.11 | $24 | $23 | | $102 |
| 57 | 2023 | $49.84 | $27 | $3.11 | $24 | $23 | | $101 |
| 58 | 2024 | $49.64 | $27 | $3.11 | $24 | $23 | | $101 |
| 59 | 2025 | $49.44 | $27 | $3.11 | $24 | $23 | | $100 |
| 60 | Escalation, 2004-25 | -0.399% | -0.23% | 0.00% | -0.32% | -0.34% | | -0.342% |
| 61 | | | | | | | | |
| 62 | | | | | | | Quarterly | -0.00085682 |

**Figure L-60: Year-by-Year Real Levelized Costs**

Not all of the $108/kWyr is construction cost. Figure L-59 specifies the portion of this that is planning cost, and the difference is the basis from the construction cost rate estimate illustrated in Figure L-61. The detailed construction cost rate calculation for this CCCT already appears as the example on page L-70. Applying the planning fraction of construction costs to the total construction cost in $M/MW gives the planning cost rate in Figure L-62. Recall that, despite the number of periods for planning that appears in Figure L-59, the number of periods is taken as one (1) when the user models planning costs as sunk, as does the regional model. This planning cost rate matches that in Figure L-56.

| | | |
|---|---|---|
| CCCT | | |
| | RL$/kWyr | $101.50 |
| | 1/#per | 0.125 |
| | RL $M/MW/per/per | 0.0029199 |

**Figure L-61: Construction Cost Rate**

D72 = =D9/(1-D9)*(E5+F5)*D40

| | A | B | C | D |
|---|---|---|---|---|
| 69 | | | | |
| 70 | | **Planning Costs** | | |
| 71 | | | | |
| 72 | | CCCT | | 0.001491007 |
| 73 | | | | |

**Figure L-62: Planning Cost Calculation**

Having reproduced the values in Figure L-56, the final step is to verify the costs in Figure L-58. From the status codes, it is evident that construction proceeds without interruption. The optional phase of construction takes four periods and the committed phase takes four periods. Figure L-63 reproduces the costs in each period of Figure L-58. Column D identifies the 0-based period, and the costs begin in period 25 for cohort 25. Column E is just the period escalation factor, i.e., one plus the escalation rate, all raised to the number of periods. Column F has the one-time sunk cost for planning, just the escalation factor times the capacity times the planning rate. (This and the other formulas here are as in the description of columns F through I on page L-70.) In column G, rows 15 through 18, the formula is identical except that the formula uses the construction cost rate instead of the planning rate. The formula appears in the equation window at the top of the page. In column G, row 11, the formula is the same as that in rows 15 through 18, except multiplied by four because all the optional construction costs are "pulsed" into the first period. The reader may now compare the cumulative costs in column H with the costs in row 465 of Figure L-58. Because there is only one active cohort, these costs match those in row 457.

This concludes the description of the new resource capital costing and planning flexibility representation in the portfolio model. This section described the portfolio model's concept of planning and construction flexibility, including features such as market addition of plants, sunk costs for planning, and pulsed construction costs. It presented the three ranges in the workbook that implement new resource additions and planning flexibility. In illustrating the range that specifies the resource plan, it provided some background on the reasons why the Council chose planning commitments to describe the plan and how they selected the planning intervals. Finally, the section reproduced the costs associated with a cohort, using special UDFs that identify the construction status and costs of any specific cohort.

Two areas of modeling are conspicuously absent: summarizing the costs and development of the decision criteria that drive both the DSI and the planning flexibility UDFs results. The present value calculations are in the following subsection. The important issue of decision criteria has its own section following this one.

G16 = =E16*$C$3*$C$5

| | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| 2 | escalation | -0.0008568 | per quarter | | | | |
| 3 | cap | 610 | MW | | | | |
| 4 | planning rat | 0.00149 | $M/MW/per^2 | | | | |
| 5 | constr rate | 0.00292 | $M/MW/per^2 | | | | |
| 6 | | | | | | | |
| 7 | | Column | Period | escl | incr plng | incr cnstr | cum |
| 8 | | | | | (M$) | (M$) | (M$) |
| 9 | | AO | 23 | | | | 0.000 |
| 10 | | AP | 24 | | | | 0.000 |
| 11 | | AQ | 25 | 0.9788 | 0.890 | 6.973 | 7.864 |
| 12 | | AR | 26 | 0.9780 | | | 7.864 |
| 13 | | AS | 27 | 0.9771 | | | 7.864 |
| 14 | | AT | 28 | 0.9763 | | | 7.864 |
| 15 | | AU | 29 | 0.9754 | | 1.737 | 9.601 |
| 16 | | AV | 30 | 0.9746 | | 1.736 | 11.367 |
| 17 | | AW | 31 | 0.9738 | | 1.734 | 13.101 |
| 18 | | AX | 32 | 0.9729 | | 1.733 | 14.834 |
| 19 | | AY | 33 | 0.9721 | | | 14.834 |
| 20 | | AZ | 34 | 0.9713 | | | 14.834 |
| 21 | | BA | 35 | 0.9704 | | | 14.834 |

**Figure L-63: Costs in Each Period**

## Present Value Calculation

Previous sections have presented the concepts, equations, and formulas for computing the cost of each source of load and energy. Loads, including smelter loads, and resources such as thermal generation, hydrogeneration, conservation, contracts, and renewables -- all of these produce period costs. As seen in the last section, the portfolio model treats the fixed costs associated with capital investment, fuel, and O&M as real levelized period costs, as well. The final step in the portfolio model is to compute the total net present value from these period costs.

The net present value calculation appears in column {CV}. For example, the net present value cost for the on-peak non-DSI loads is in row {323}:

```
=8760/8064*NPV(0.00985340654896882,$R323:$CS323)*(1+0.00985340654896882)
```

This equation has three multiplicative terms. The first term is the ratio of the number of hours in a calendar year to the number of hours in a standard year. As described in section "Single Period," all period calculations assume standard months, quarters, and years. This first term performs the cosmetic task of converting dollars per standard year to dollars per year. The portfolio model does not concern itself with the exact number of on- and off-peak hours in each quarter.[27]

The second and third terms discount the period costs to the first period. The Excel net present value function NPV discounts cash flows to the period immediately *before* the first cash flow. The third term merely moves it up to the first cash flow. The discount rate is the discount per quarter, given the four percent discount per year.

This formula represents an unfortunate instance where data appears in code. The ratio of hours in a calendar year to a standard year is a constant and might be appropriate for a formula like this one. The discount rate, however, should never appear in a formula like this. This formula is a vestige of an earlier version of the portfolio model.

The formulas in {CV1063} and {CV1065} total the net present value cost contributions for energy use and production and for the fixed costs of new resources. The only resource that does not contribute to the total net present value cost is the supply curve associated with commercial use of hydrogeneration. The section "Price-Responsive Hydro" explains this convention.

Cell {CV1065} is a Crystal Ball "forecast" cell. It has the default sky-blue color of such cells. Crystal Ball tracks the values in forecast cells and makes them available to the OptQuest add-in. One may think of these cells as the primary "output" of the worksheet.

Below the formulas in cell {CV 1065}, the reader will recognize several cells as risk measures. In fact, it is not possible to determine the risk associated with the distribution of net present value costs from a single future. Instead, after all 750 futures have been simulated and their total system costs calculated by this workbook, and an Excel subroutine uses Crystal Ball functions to recover the 750 values for {CV 1065}, stored in memory. The subroutine then calculates risk measures such as $\text{TailVaR}_{90}$ and places the resulting values in Crystal Ball "forecast" cells for use by that application. The section "Using the Regional Model" explains this process.

## Decision Criteria

The previous section introduced the concept of decision criteria. Both the DSI smelter startup/shutdown decision and the construction decision for new electric power resources rely on decision criteria. Conservation also uses a decision rule to determine whether to buy more conservation than short-term cost effectiveness would suggest, and if so how much.

This section begins with background on what decision criteria are, how the regional model uses them, and some of the discoveries and considerations that went into selecting the decision criteria. The specific criteria for new resources, conservation, and DSIs then

[27] As explained at the beginning of the section "Single Period," if it became important to do so, a user could recover the exact calendar year costs by applying to each standard quarter the weighting of on- and off-peak hours in that quarter relative to the other quarters in the year.

each have their own sections. The sections describe the particular aspects of each criterion and trace the formulas that implement them though the sample workbook.

## Background

The defining characteristic of planning under uncertainty is imperfect foresight. With perfect foresight, there would be no risk. A risk model must therefore incorporate at least two special features. First, a risk model must have the ability to add resource capacity or other course of action without the benefit of perfect foresight. Most production cost or system simulation models capable of capacity expansion use techniques that assume perfect foresight. For example, these models may remove resources that do have sufficient value in the market to cover forward going fixed costs or add resources that would make a risk-adjusted profit in the market. An iterative process removes or adds resources until all new resources would just cover their risk-adjusted costs. Alternatively, a capacity expansion model may choose a capacity expansion schedule that minimizes cost. Both of these approaches must determine future hourly costs and prices to feed back to the capacity expansion algorithm. This feedback determines whether some adjustment to the construction schedule is necessary. If the model modifies the schedule, of course, the model must re-estimate future costs and price changes. The process repeats until the model finds a solution. These estimates of future costs and prices represent perfect foresight regarding how resources, costs, and prices affect one another. Perfect foresight, however, is contrary to the principles of risk analysis.[28]

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

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

All decision criteria implement the concept of causality. Decisions to build, shut down or start up smelters, and so forth rely on the strict past (prior periods). That is, the logic that controls construction progress or smelter operation references the criterion value in the *prior* period. The reasons appear above in the section "Concept Of Causality," beginning on page L-58.

All decision criteria formulas are in the Twilight Zone, rows {223} through {316}. The model updates these before beginning any period calculations and with any iterations of

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

the RRP algorithm. The reason this is necessary is that some intermediate values that contribute to decision criteria will change with each iteration, such as power plant value when electricity price changes.

## New Resource Selection

The section "New Resources, Capital Costs, and Planning Flexibility" describes how the model uses a decision criterion to halt or continue activity during the earlier phase of construction. The model incorporates such behavior to permit the valuation of planning flexibility.

Given how important the decision criterion is to assessing planning flexibility, it is natural to ask what alternatives exist and why the Council chose this particular decision rule. The first rule implemented in early versions of the portfolio model was valuation using forward prices. One concern that arose when consideration turned to valuing conservation is that plans with more conservation often received substantial value by virtue of "being there" when high market price excursions occurred.[29] Resources that used only valuation in the market could only react to these excursions; often completing construction after the excursion subsided. Although this may help describe behavior during the 2000-2001 energy crisis, a more experienced market will probably pay careful attention to physical resource adequacy in the future. Moreover, when a resource-load balance criterion replaced the market valuation criterion in the portfolio model, the feasibility space and its efficient frontier displayed reduced risk at no increase in cost. Resource-load balance does a better job of predicting the need for resources.

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

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

[29] This value comes not only from the advantageous resource-load position, but also from price moderation due to the additional resources. This raised the question of whether other resources, built to maintain some reserve margin, would not also benefit plans. This turns out to be the case, although – as the section "Conservation Value Under Uncertainty" describes – conservation often can serve this role a lower net cost.

If the model needs a resource to meet anticipated future load, the criterion consults pertinent forward prices for each resource. For example, for a gas-fired power plant, the model would estimate the plant's value from forward prices for electricity and natural gas and compare those to capital and other fixed costs to determine whether the plant would pay for itself. If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues.

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

Model Representation

In the workbook, we will trace the decision criterion for the CCCT backward from the final value. This section will also point out any differences with the decision criteria for the coal plant, SCCT, demand response, and wind. Demand response and wind, in particular, merit a paragraph each at the end of this discussion.

The CCCT new capacity UDF in cell {AQ455} points to the decision criterion in cell {AP302}. The formula in cell {AP302} is as follows

```
=IF(AP$297<$O303,IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1),-1)
```

This formula first checks to determine whether the forecasted crossover point for resource-load balance is less than the lead time for construction of the CCCT. If that is false, then the decision criterion is set to -1 (no-go). Otherwise, the formula sets the value to +1 (go) if the CCCT either is expected to make money in the market or is the least cost resource among the available alternatives and to –1 otherwise. It may be useful to parse the formula to better understand it. The outside "if statement"

```
=IF(AP$297<$O303,...,-1)
```

checks the forecasted crossover point in cell {AP297} against the number of periods for construction in cell {O303}. If the lead time for construction is greater than the forecasted crossover time, the formula returns to –1 indicating that construction is unnecessary and undesirable. Otherwise the inner if statement is executed

```
IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1)
```

the first condition in the OR test

```
AP253>=0
```

checks whether the CCCT makes money in the market. The second condition in the OR test

```
AP253>(AP$282-$R$283)
```

checks to see whether the cost of the CCCT is within some small interval, specified in {R283}, of the minimum cost among all resources, calculated in cell {AP253}. There are four key variables in this formula:

- Construction lead time
- Neighborhood of the minimum cost
- Forecasted Energy Margin Crossover Point
- Market Viability

The first two variables are easy to describe. The construction lead-time is the sum of the periods for optional and committed construction:

```
=C455+D455+E455
```

The first term in the sum points to the number of periods for planning and siting, but that value is zero for all new resources in the regional model.

The test with the minimum uses a neighborhood for technical reasons. The model does not test whether the cost of the CCCT is *exactly* the minimum cost among all resources, because of the problem associated with comparing any two real numbers in computer code. That is, some manipulation, e.g., finding the minimum of a set of numbers, may corrupt the minimum by an infinitesimal amount. This corruption could render the comparison invalid. To avoid this situation, the formula instead checks whether the resource is within some very small neighborhood of the minimum.

The remaining two variables, Forecasted Energy Margin Crossover Point and Market Viability, are more complex and merit their own sections. These are the next two sections.

### Forecasted Energy Margin Crossover Point

The forecasted crossover point ({AP297}) is an estimate of when requirements will surpass resources. The calculation of load requirements for this estimate, however, includes the addition of a user-specified, energy reserve margin target. This user-specified target is under the control of the optimization software through its assignment to a Crystal Ball decision cell.

The formula in cell {AP297} is the following

```
=IF(AP295<AP296,(AP295-$T$3)*12/(AP296-AP295),IF(AP295<$T$3,-1,100))
```

This formula checks to see if resource net of total load ({AP295}) has declined over the last three years. If so, it uses the rate of decline to determine how many periods will pass before resources decline below the load plus energy reserve margin. If not, it checks whether resource net of total loads is below the energy reserve margin target ({$T$3}). If so it returns the value -1. Otherwise it returns the value 100. These values are the number of periods before crossover is anticipated to take place. Negative one (-1), of course, will be less than the construction time for any resource and will therefore result in a positive value for the decision criterion, other factors permitting. The value 100 exceeds the construction time of any resource and would typically result in a negative decision criterion value.

It can of course happen that the balance ({AP295}) has declined over the last three years but is already below the target energy-reserve margin. In this case, the formula will return a negative number. This number is a back-cast of the number of periods in the past that the balance slipped below the target. Any negative value signals that construction is necessary.

The cell {AP295} computes resources net of loads by adding the various terms immediately above that cell in the worksheet, as shown in Figure L-64. The model updates these for the new values under this future. (The Figure L-64 also demonstrates the situation described above where the balance has declined but is already below the 3000MW target energy reserve margin, and the value returned is negative.)

The load estimate in cell {AP289} is the hydro year's average, weather-corrected non-DSI load (the range {AL126: AO126}), plus the DSI load in the final period. The model's weather corrected load is simply the load, less the stochastic part that represents weather variation in the winter and summer. The reader will find a complete discussion of load representation in Appendix P.

AP295 = =SUM(AP289:AP294)

| | Q | | AP |
|---|---|---|---|
| 287 | | | |
| 288 | Reserve Margin, ver 2: annual energy (MWa) | | |
| 289 | loads | | -21000 |
| 290 | contracts, net import | | 252 |
| 291 | conservation | | 613 |
| 292 | new capacity | | 0 |
| 293 | variable capacity thermal resources | | 1,973 |
| 294 | existing resources | | 20895 |
| 295 | **total (MWa)** | | 2733 |
| 296 | **total (MWa) three year's prior** | | 3091 |
| 297 | periods to hit target reserve margin | | -9.0 |

**Figure L-64: Resources Net of Loads**

Net import contract energy in MWa (cell {AP290}) is given by

=4/7*AVERAGE(AL84:AO84)+3/7*AVERAGE(AL88:AO88)

This is merely the average of contracts (MWa) over the previous four quarters on peak (row {84}) and off peak (row {88}), weighted by the respective number of on- and off-peak hours in the standard quarters.

Conservation in MWa (cell {AP291}) is

=(SUM(AL377:AO377)+SUM(AL386:AO386)+SUM(AL741:AO741)+SUM(AL749:AO749))/(4*(1152+864))

This formula references the lost opportunity (rows 377 and 741) and discretionary (rows 377 and 741) conservation energy in MWh on- and off-peak over the last four quarters. The average MW are then this sum, divided by the hours in a standard year, 4*(1152+864).

New capacity in MWa (cell {AP292}) is

=AO455+AO469+AO483+0.3*(AO509+AO519)

The CCCT, SCCT, and coal-fired capacity in the last period is added to 30 percent of the two wind unit capacities. Energy from the wind units must be discounted, because of the low availability of wind. Missing here is any capacity from demand response (DR). DR is considered an emergency resource in these studies and its expected energy contribution is nil.

"Variable capacity thermal resources" (cell {AP292}) is a misnomer. In fact, there is a substantial amount of renewable (wind) energy in this sum. This capacity changes from year to year. It requires summing the annual average capacity of those resources.

```
=SUM(AVERAGE(AL345:AO345),AVERAGE(AL355:AO355),1497+0.3*(AVERAGE(AL536:AO536)-
1497),AVERAGE(AL610:AO610))
```

In this workbook, developed before the draft plan, three generic thermal resources are retired over 10 years. The average capacity for each appears as the first, second, and forth terms in this sum. Must run resources, the third term, include thermal resources that stay at the same capacity (1497 MW) over this period and wind resources that increase in capacity. There is an error in this formula. The energy of the wind is discounted twice, once in the values reported in the range {AL536:AO536} and again by the formula. In the version of the model used to create the final plan, there are no thermal unit retirements, and the double-discounting does not take place. The cell is also labeled more accurately, "variable must-run firm energy."

The "existing resources" (cell {AP293}) are those resources that have annual energy production that is constant over the study. Hydro generation energy is included at the critical water amount. The formula in cell {AP293} merely adds the critical-water hydro

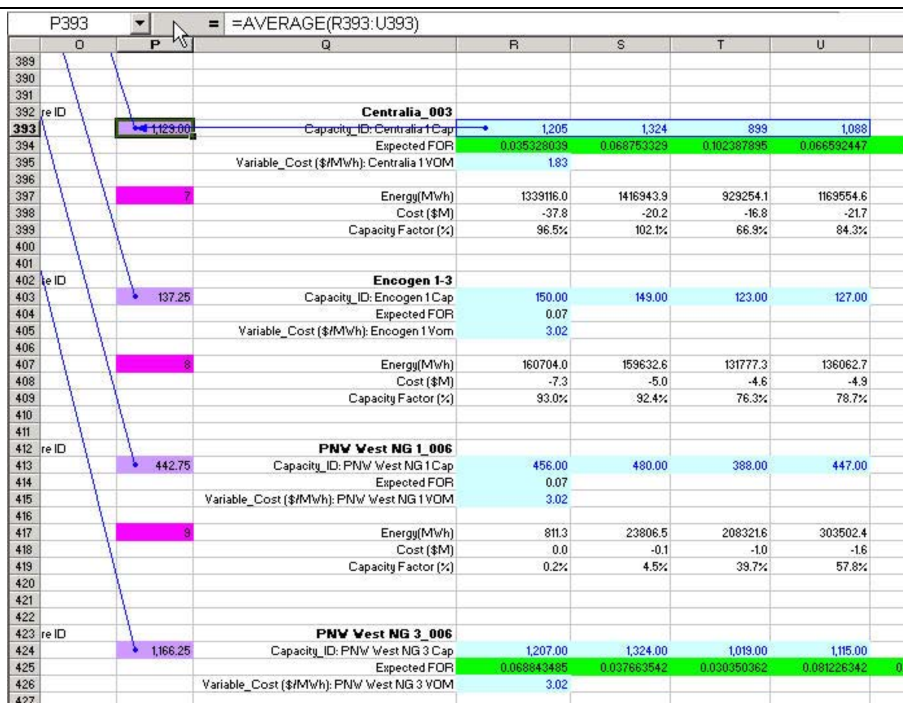



**Figure L-65: Resources with Constant Annual Energy Availability**

energy, a user-specified constant, and the total capacity for the fixed-capacity resources. The total fixed capacity in cell {I289} merely points to averages of energies across the hydro year for each relevant plant, as illustrated in Figure L-65.

### Market Viability

Returning to the beginning of this section, "Model Representation" on page L-83, the last variable in the decision criterion for new resources is market viability (cell {AP253}). The market viability test is made in a set of rows just above those where the worksheet determines resource-load balance. As explained above, the intent is to simulate forward curves values and calculate whether or not the value of the resource in the market would cover its fixed costs. Figure L-66 shows the formula for this cell.

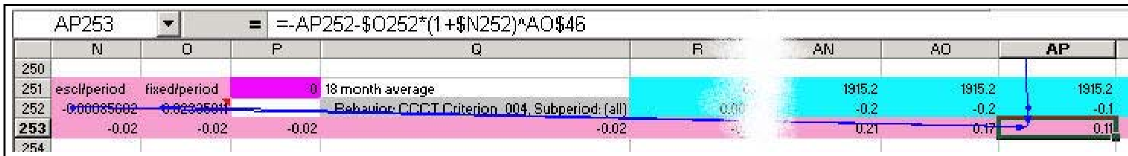



**Figure L-66: The Net Market Value Test**

The first term in the formula {AP252} is the value of the CCCT in the market. It contains a call to the spread option UDF described in the section "Thermal Generation," above, which returns the value (2004 $M) in the market. (See Figure L-67.) This call is identical to the one for the generic CCCT itself with three exceptions: the size of the plant is 1MW, the electricity price is an 18-month average of flat electricity prices, and the natural gas price is also an 18-month average. The market viability valuation uses equal 1MW capacities for all new resource candidate to normalize the value to dollars per MW. The 18-month averages of past prices, as explained above, is used as a surrogate for forward prices and to reflect the time necessary for owners to develop confidence in the forward prices. The development of these stochastic prices appears in Appendix P.

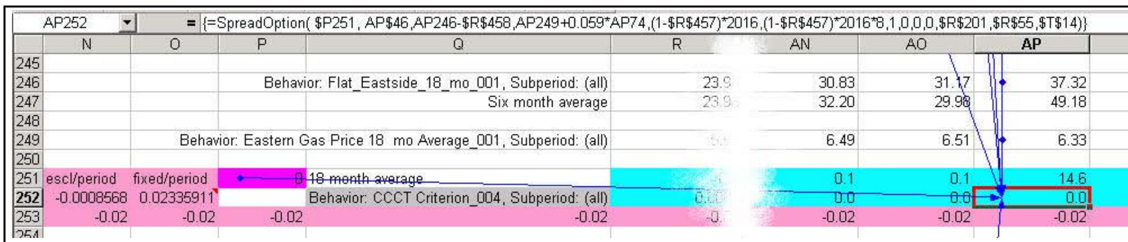



**Figure L-67: Value of Plant in Market**

The second additive term in formula {AP252}, \$O252*(1+\$N252)^AO\$46, is the fixed cost per MW. (See Figure L-66.) The cell {\$N252} references the escalation rate per period for CCCT fixed costs, and the cell {AO\$46} is the zero-based period index. The formula for 2004\$ fixed cost per MW in cell {\$O252} is

=SUM(D455:E455)*I455

which sums the number of optional and committed construction periods and multiplies it by the real levelized millions of dollars per period squared. The cost for planning periods, which are zero anyway, should not be included as they are sunk cost for the plan.

For demand response, the treatment is identical to the CCCT decision criterion with the following exceptions. Demand response (DR) is modeled as a thermal unit with a dispatch cost of $150/MWh (2004$). Because DR programs require little time to implement, they can respond more quickly to changing circumstances. Their relatively small set-up cost minimizes the risk of having the opportunity disappear. For this reason, the DR decision criterion does not use an 18-month average electricity price, but uses the period price instead. Note also that in both the draft and final plans, the plans hard-wire the plan for DR development (row {7}) rather than placing it under the control of the optimizer. The model still uses the decision criterion logic.

For wind generation, the treatment is identical to the CCCT decision criterion with the following exceptions. The value of wind in the market (cell {AP$277}) is

=2016*0.3*(AO$506-AP$247)/1000000

As before, the implied capacity is 1MW. The value in 2004 $M is then just the energy times the market price adjusted for any costs. The energy is 1MW times the number of hours in the period, times the capacity factor. The adjusted market price is the six-month average of flat electricity prices (cell {AP$247}), less the net of integration cost, production tax credit, green tag credit, and variable O&M (cell {AO$506}). The model uses a six-month average for electricity price instead of the 18-month average because the Council believed that, with the shorter construction cycle for wind, owners would want to respond more quickly and would not take as much time to build confidence in their lower dollar commitment to the more modular wind units. This represents an approach to averaging past prices that fall between that of DR and the thermal resources.

This concludes the discussion of decision criteria for new resources. One shortfall of these criteria is that they include the full fixed cost of construction irrespective of where plants are in their construction cycle. That is, forward-going construction decisions should treat costs associated with past construction as sunk cost. Modeling this economics would probably require a significant revision to the new capacity-planning flexibility UDF, as such detail must be tracked by cohort. It might make for even more realistic behavior, however.

## Conservation

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

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

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

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

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

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

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

These considerations drove the design of the decision criteria for conservation. The decision criterion takes the form of a price. This price and a supply curve determine how much conservation to develop in a given period. Both lost-opportunity and discretionary conservation[30] criteria are the sum of two terms. The first term approximates the cost-effectiveness standard. This is a "myopic" estimate of cost effectiveness, which depends on the specific future and changes over time in that future. The second term determines how much additional conservation to deploy compared to the cost-effectiveness level. This second term, a price adjustment, is under the control of the logic that helps the portfolio model find the least-cost plan, given a fixed level of risk.

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

Lost Opportunity Conservation

Lost opportunity conservation modeling uses the supply curve UDF described in the section "Conservation," beginning on page L-44. In the column {AQ}, the model accesses the lost-opportunity conservation supply curve using the price {AP$233+$R$375}. (See Figure L-68.) The first term represents the cost-effectiveness standard. The second term, {$R$375}, merely points to a cell which, in turn, references a Crystal Ball decision cell. The optimizer can change the value in the decision cell to specify the plan. Our focus here will be the cost-effectiveness measure in cell {AP$233}.

Note that the formula in cell {AQ377} also accesses the response to load factor in cell {AP240}. This is not part of the decision criterion. This appendix addresses the response to load factor in section "New Resources," beginning on page L-99.

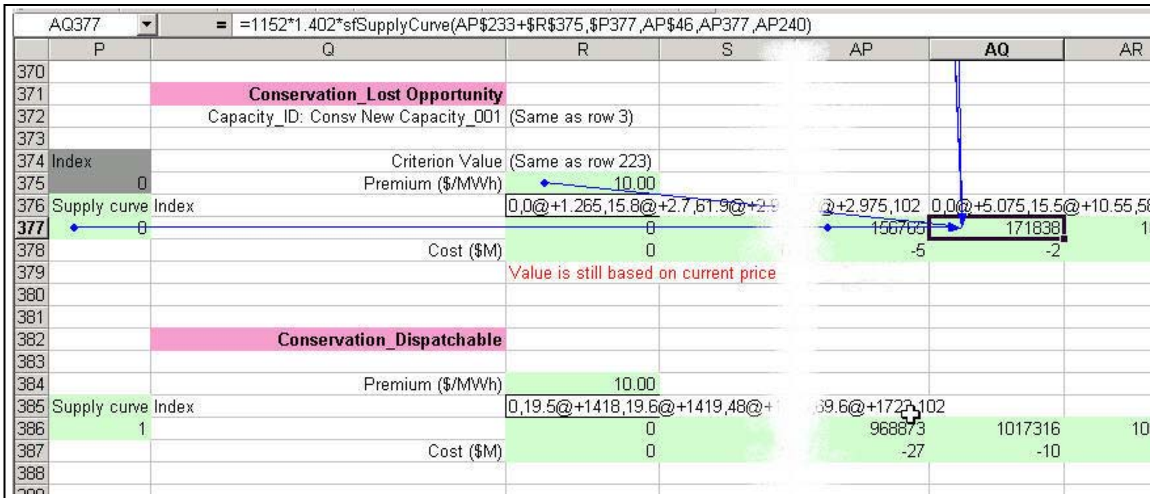



**Figure L-68: Criterion References for Conservation**

The formula in cell {AP$233} clearly does nothing more than find the highest value in the preceding row since the beginning of the study:

=MAX($Q$232:AO232)

This facilitates the "sticky downward" behavior. The value of the decision criterion will always be the highest value the preceding row achieves. As explained above, this represents such things as market transformation and the implementation of codes and standards.

Columns in the preceding row uses a fairly complicated formula. For example in column {AO}, the formula is

=MAX(0,20-AN46)*$Q$232/20+MIN(20,AN46)*
AVERAGE(OFFSET($Q$230,0,MAX(0,AN46-19),1,MIN(AN46+1,20)))/20

(Column {AO} is the last column referenced by cell {AP$233}.) This formula computes a five-year (20 period) average of the electricity price values in row {230}. The electricity price values in row {230} are weighted by the amount of conservation on- and off-peak. We will return to them shortly.

The reason for the complexity of the formula is that a single cell is providing an estimate of electricity prices in the past. For many prices and other stochastic variables, the worksheet contains explicit values for the time before the beginning of the study wherever necessary. For such a long reach into the past, however, a different approach was necessary. This formula uses the average of electricity prices over the past 20 periods, unless the beginning of the averaging interval is less than 20 periods in the past. In the latter case, it uses the value in cell {$Q$232} to form a weighted average, giving the value in {$Q$232} to as many periods as precede the beginning of the study.

The electricity price values in row {230} are of the form

=AP$207*1.402*4/7 + AP$219*0.465*3/7

This weighs the on-peak electricity price west of the Cascades by the expected on-peak conservation savings (1.402) and the fraction (4/7) of hours on peak during a standard quarter. The second term is the off-peak contribution, calculated in an identical fashion. Much of the load and conservation potential lies west of the Cascades.

Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection "Supply Curves" of the section "Resource Implementation and Data," below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of the weighting factor 1.402 appears in that section.

Discretionary Conservation

Returning to Figure L-68 and the worksheet, the user finds a near-identical supply curve formula for discretionary conservation in cell {AQ386}. As in the lost-opportunity case, the supply curve access price is the sum of two values, the cost-effectiveness standard and value that references a Crystal Ball decision cell, which is under the control of the optimizer.

The cost-effectiveness calculation is different from that for lost opportunity. In cell {AP235}, which cell {AQ386} references, we find

=AVERAGE(AH230:AK230)

Because discretionary conservation is available for implementation at any time, codes and standards are not necessary to capture it. Utilities can wait until prices and the cost-effective standards increase before taking action. This formula averages the conservation-weighted electricity price from not the immediate past year, but the *preceding* year, to obtain the cost-effectiveness level. The reason for looking back two years is to reflect budgeting delays. That is, utilities usually set a budget earlier in the year for the following year and follow that schedule the following year. When they prepare that budget, however, they would be looking back over the preceding year.

### DSIs and Smelters

As with thermal plants, the model uses prices for aluminum and electricity over the preceding 18 months as a surrogate for forward prices. These inform the decision to shutdown or start up each of the seven smelters in the region. (See section "DSIs" for a description of the algorithm for smelter operation.)

The UDF for smelter capacity in cell {AQ327} references the 18-month average of flat electricity prices in row {227} and the 18 month average of aluminum prices in row {270}. These averages are straight forward. The model of electricity prices and aluminum prices appears in Appendix P.

This section addressed decision criteria. It reviewed some of the experiences that led to the final selection of decision criteria for new resources, and it explained the calculation of resource-load balance and market viability of resources. It also explained the thinking behind, and formulas that implement, decision criteria for conservation and smelters.

With an understanding in principle of how various ranges in the worksheet function, this appendix now turns to the detailed representation of plants and conservation, including the model's data.

# *Resource Implementation and Data*

This section begins with the procedure by which existing regional resources are aggregated into the thirty plants in the regional model. It dedicates extra sections to the treatment of the region's independent power producers and system benefit charge (SBC) wind. It then addresses the candidate new resources, such as the generic CCCT, coal, and wind plants used for capacity expansion. Because forced outages are really an aspect of the future, detailed description of their modeling appears in Appendix P, although the key descriptive statistic, the effective forced outage rate (EFOR), appears in this appendix. Conservation is a candidate for meeting new requirements, and there is a section on data for the conservation supply curves and on conservation energy weighting assumptions. The section concludes with documentation for the contract data used in the model.

## Existing Resources

The portfolio model consolidates regional resources into surrogates with identical technology and similar operating characteristics. Besides simplifying the worksheet, this reduces the computation time.[31] Each surrogate has regional plants of identical fuel type

[31] Each UDF call requires approximately 300 microseconds. This execution cost appears to be largely independent of the amount of VBA code behind the UDF. The execution cost is associated primarily with Excel's handling of the function call. Each plant in the regional model occupies 80 periods and two subperiods. This results in 48 milliseconds per plant or about 21 plants per second. This computational burden does not include the calls to other UDF's, such as those for planning flexibility or smelter operation. If a worksheet requires one second to compute, a thousand plans under 750 futures -- a typical requirement for the construction of a feasibility space -- would require approximately 8.7 days of computation time. Although the regional model wound up with about 30 surrogate plants, distributed processing across 10 machines reduced computation time to one day. Although modeling each of the 115 plants individually is feasible in principle, it would have increased these runtimes fourfold with questionable benefit.

and technology (CCCT, SCCT, etc.). Surrogates also represent plants of similar variable operating cost, which plant heat rate largely determines. Surrogates have a heat rate equivalent to the capacity-weighted heat rate of their constituents.

Monthly availabilities for the surrogate are the sum of the regional plants' monthly availabilities. The monthly availability of existing regional power plants appears in Figure L-69 and Figure L-70 [**7**]. Genesys simulations generate the monthly availabilities [**8**]. The simulations rely on the database that the Council uses to populate its Aurora model. These availabilities reflect maintenance outages but not forced outages. The reference for forced outage data is [**9**]. The model captures forced outages through a stochastic variable or explicit capacity de-ration. (See Appendix P and below.)

The characteristics of the surrogate plants appear in Figure L-71[**10**]. The quarterly availabilities are averages of the corresponding monthly availabilities. Forced outage rates reflect forced outage rates of the constituent plants. For some of these plants, the model uses capacity duration to reflect forced outages. The policy for determining whether to use stochastic forced outages or capacity de-ration is that larger existing plants use stochastic forced outages. Smaller existing plants contributed little risk. Modeling stochastic forced outages for new plants represented a challenge not attended to by the regional model. In particular, the reliability of an ensemble of plants is better than that of a single plant. As the model added capacity, either the forced outage rate characteristics of the ensemble would have to improve, or the model would have to provide each cohort with its own stochastic forced outage schedule. Both of these approaches presented a considerable programming challenge for questionable benefit. This version of the regional model, therefore, takes the more simplistic approach.

In the workbook, the first on-peak resource listed is a surrogate resource, "PNW West NG 5_006." (The meta-model Olivia generated these names, and the "006" has no particular significance. See section "Olivia" below for information about this model.) In Figure L-72, auditing reveals the references for cell {AQ 339}. This cell contains the UDF for computing energy for a thermal resource. (See section "Thermal Generation.") Above, this appendix has described most of the references. The following, however, are noteworthy. First, the UDF is referencing the stochastic forced outage rate in cell {AQ 336}. The model uses this forced outage rate to modify the assumed availability of the plant. Second, the seasonal availabilities for this surrogate plant are evident in row 335, columns R through U. The formula cycles among these four availabilities. The cycling assures proper representation of seasonal variation and differences due to maintenance.

The regional model represents other thermal surrogate resources similarly. Must-run resources are an exception. The energy and value for the must-run units are simple to calculate because energy is uncorrelated with market price. The value is simply the market price of electricity times the energy. In addition, because must-run resources include system benefit charge (SBC) wind generation, and the wind capacity increases over time, the capability references do not cycle as with thermal resources. Instead, the UDF references typically point to the capability in the same period. SBC wind is the subject of the next section.

| Unit Name | Alternative name/description | Aggr_Unit | Sep (MW) | Oct (MW) | Nov (MW) | Dec (MW) | Jan (MW) | Feb (MW) | Mar (MW) | Apr (MW) | May (MW) | Jun (MW) | Jul (MW) | Aug (MW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Bailey (Clatskanie GT) | Alden Bailey | PNW West NG 7 | 10 | 11 | 11 | 11 | 11 | 11 | 10 | 9 | 9 | 9 | 10 | 10 |
| Beaver 1-7 | Beaver | PNW West NG 5 | 475 | 487 | 498 | 504 | 505 | 500 | 435 | 370 | 364 | 359 | 469 | 468 |
| Beaver 8 | Beaver 8 | PNW West NG 6 | 23 | 23 | 24 | 24 | 24 | 24 | 22 | 20 | 19 | 19 | 22 | 22 |
| Big Hanaford | Big Hanaford | PNW West NG 3 | 233 | 239 | 245 | 248 | 248 | 246 | 214 | 182 | 179 | 176 | 230 | 230 |
| Biomass-One 1 | Biomass One | Must Run | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Boardman 1 | Boardman | Boardman 1 | 556 | 556 | 556 | 556 | 556 | 556 | 467 | 379 | 379 | 379 | 556 | 556 |
| Boise Cascade Medfor | Boise Cascade Medfor | PNW West NG 1 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Boulder Park | Boulder Park | PNW East NG 6 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Boundary GT | (emergency) | PNW Oil | | | | | | | | | | | | |
| BP (Cherry Point) GTs | BP Cherry Point GTs | PNW West NG 7 | 69 | 70 | 72 | 73 | 73 | 72 | 66 | 59 | 59 | 58 | 68 | 68 |
| Centralia 1 | Centralia 1 | Centralia | 670 | 670 | 670 | 670 | 670 | 670 | 563 | 456 | 456 | 456 | 670 | 670 |
| Centralia 2 | Centralia 2 | Centralia | 670 | 670 | 670 | 670 | 670 | 670 | 563 | 456 | 456 | 456 | 670 | 670 |
| Chehalis Generation Facility | Chehalis Generating | PNW West NG 3 | 489 | 501 | 513 | 519 | 520 | 515 | 448 | 381 | 375 | 369 | 483 | 482 |
| Coffin Butte 1 | Coffin Butte | Waste Burner | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Colstrip 1 | Colstrip 1 | Colstrip 1&2 | 307 | 307 | 307 | 307 | 307 | 307 | 258 | 209 | 209 | 209 | 307 | 307 |
| Colstrip 2 | Colstrip 2 | Colstrip 1&2 | 307 | 307 | 307 | 307 | 307 | 307 | 258 | 209 | 209 | 209 | 307 | 307 |
| Colstrip 3 | Colstrip 3 | Colstrip 3&4 | 740 | 740 | 740 | 740 | 740 | 740 | 622 | 504 | 504 | 504 | 740 | 740 |
| Colstrip 4 | Colstrip 4 | Colstrip 3&4 | 740 | 740 | 740 | 740 | 740 | 740 | 622 | 504 | 504 | 504 | 740 | 740 |
| Columbia Generating Station | Columbia Generating | Must Run | 1170 | 1170 | 1170 | 1170 | 1170 | 1170 | 944 | 720 | 720 | 720 | 1170 | 1170 |
| Combine Hills I | Combine Hills I | Must Run | 12 | 11 | 17 | 22 | 24 | 32 | 7 | 10 | 8 | 7 | 7 | 11 |
| Condon Wind Project Phase I | Condon 2001 | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| Condon Wind Project Phase II | Condon 2002 | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| Corrette | J.E. Corrette | Corrette | 160 | 160 | 160 | 160 | 160 | 160 | 134 | 109 | 109 | 109 | 160 | 160 |
| Coyote Springs 1 | Coyote Springs 1 | PNW East NG 3 | 208 | 215 | 221 | 226 | 226 | 223 | 192 | 163 | 159 | 156 | 202 | 203 |
| Coyote Springs 2 | Coyote Springs 2 | PNW East NG 3 | 258 | 267 | 274 | 280 | 280 | 276 | 238 | 202 | 197 | 193 | 251 | 252 |
| Crystal Mountain 1 & | Crystal Mountain 1 & | PNW West NG 6 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| D R Johnson Lumber (Riddle, Coge | Cogen II | Must Run | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Danskin | Danskin (Evander And | PNW So ID NG 2 | 83 | 86 | 88 | 90 | 90 | 89 | 77 | 65 | 63 | 62 | 81 | 81 |
| Eastsound 4 & 5 | Eastsound 4 & 5 | PNW West NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Encogen 1 | Encogen 1-3 | Encogen 1 | 151 | 154 | 158 | 160 | 160 | 159 | 138 | 117 | 115 | 114 | 149 | 148 |
| Equilon GTs | Equilon GTs | PNW West NG 7 | 37 | 38 | 38 | 39 | 39 | 39 | 35 | 32 | 31 | 31 | 36 | 36 |
| Everett Cogen 1 | Everett Cogen | Must Run | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Finley | Finley | PNW East NG 6 | 25 | 26 | 26 | 27 | 27 | 27 | 24 | 22 | 21 | 21 | 24 | 24 |
| Foote Creek | Foote Creek | Must Run | 17 | 15 | 25 | 31 | 34 | 45 | 11 | 14 | 12 | 10 | 10 | 15 |
| Frederickson 1 | Frederickson  (PSE) | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| Frederickson 2 | Frederickson  (PSE) | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| Frederickson Power 1 | Frederickson Power ( | PNW West NG 1 | 259 | 265 | 271 | 275 | 275 | 273 | 237 | 202 | 198 | 195 | 255 | 255 |
| Fredonia 1 | Fredonia 1 | PNW West NG 6 | 117 | 120 | 122 | 124 | 124 | 123 | 107 | 91 | 89 | 88 | 115 | 115 |
| Fredonia 2 | Fredonia 2 | PNW West NG 6 | 117 | 120 | 122 | 124 | 124 | 123 | 107 | 91 | 89 | 88 | 115 | 115 |
| Fredonia 3 | Fredonia 3 | PNW West NG 6 | 57 | 59 | 60 | 61 | 61 | 60 | 55 | 50 | 49 | 48 | 57 | 57 |
| Fredonia 4 | Fredonia 4 | PNW West NG 6 | 57 | 59 | 60 | 61 | 61 | 60 | 55 | 50 | 49 | 48 | 57 | 57 |
| Frontier Energy | (no match) | Waste Burner | | | | | | | | | | | | |
| Georgia Pacific (Camas) | Georgia-Pacific (Cam | Must Run | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 |
| Georgia Pacific (Wauna) | Georgia-Pacific (Wau | Must Run | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Georgia-Pacific (Bellingham) GTs | Georgia-Pacific (Bel | PNW West NG 7 | 9 | 10 | 10 | 10 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 |
| Glenns Ferry Cogeneration | Glenns Ferry Cogener | PNW East NG 3 | 8 | 9 | 9 | 9 | 9 | 9 | 8 | 7 | 7 | 7 | 8 | 8 |
| Goldendale Energy Ce | Goldendale Energy Ce | PNW East NG 2 | 229 | 236 | 243 | 248 | 248 | 245 | 211 | 179 | 174 | 171 | 222 | 223 |
| Grays Harbor ICs | Hoquiam 1 - 5 | PNW Oil | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Hermiston Generating 1 | Hermiston Gen 1 | PNW East NG 2 | 218 | 225 | 231 | 236 | 236 | 233 | 201 | 170 | 166 | 163 | 211 | 212 |
| Hermiston Generating 2 | Hermiston Gen 2 | PNW East NG 2 | 218 | 225 | 231 | 236 | 236 | 233 | 201 | 170 | 166 | 163 | 211 | 212 |
| Hermiston Power Project | Hermiston Power | PNW East NG 1 | 581 | 600 | 617 | 629 | 630 | 621 | 536 | 454 | 443 | 435 | 564 | 566 |
| ICT PP&L/Utah&Wyo to | ICT PP&L/Utah&Wyo to | Valmy | 184 | 160 | 168 | 154 | 187 | 187 | 178 | 171 | 189 | 265 | 296 | 253 |
| Jim Bridger 1 | Jim Bridger 1 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| Jim Bridger 2 | Jim Bridger 2 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| Jim Bridger 3 | Jim Bridger 3 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| Jim Bridger 4 | Jim Bridger 4 | Bridger | 173 | 173 | 173 | 173 | 173 | 173 | 145 | 118 | 118 | 118 | 173 | 173 |
| Kettle Falls GT | Kettle Falls GT | PNW East NG 3 | 6 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 5 | 5 | 6 | 6 |
| Kettle Falls ST | Kettle Falls | Must Run | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Klamath Cogen Project | Klamath Cogeneration | PNW East NG 1 | 443 | 457 | 470 | 480 | 480 | 473 | 408 | 346 | 337 | 331 | 430 | 432 |
| Klamath Expansion (GTs) | (no match) | PNW East NG 3 | | | | | | | | | | | | |
| Klondike | Klondike | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| Libby 1 Champion | (retired) | Must Run | | | | | | | | | | | | |
| Libby 2 Champion | (retired) | Must Run | | | | | | | | | | | | |
| March Point 1&2 | March Point | PNW West NG 3 | 132 | 135 | 138 | 140 | 140 | 139 | 121 | 103 | 101 | 99 | 130 | 130 |
| Mariah | Mariah | Must Run | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Marion Solid Waste 1 | Covanta Marion | Waste Burner | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| MEAD | MEAD | PNW West NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Morrow Power | Morrow Power | PNW East NG 6 | 23 | 24 | 25 | 25 | 25 | 25 | 21 | 18 | 18 | 17 | 22 | 22 |
| Mountain View | Mountain View | PNW East NG 6 | 148 | 152 | 157 | 160 | 160 | 158 | 136 | 115 | 112 | 110 | 143 | 144 |
| Nine Canyon | Nine Canyon | Must Run | 14 | 12 | 20 | 25 | 27 | 36 | 9 | 11 | 10 | 8 | 8 | 12 |
| Nine Canyon | Nine Canyon Expansio | Must Run | 4 | 4 | 6 | 8 | 9 | 12 | 3 | 4 | 3 | 3 | 3 | 4 |
| North Side | North Side | PNW East NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Northeast | Northeast 1 & 2 | PNW East NG 6 | 62 | 64 | 66 | 67 | 67 | 66 | 57 | 48 | 47 | 46 | 60 | 60 |
| Okanogan Co PUD ICs Ph 2 | Okanogan Co. PUD ICs | PNW Oil | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| OR RPS/SBC Wind 03 | OR RPS/SBC Wind 03 | Must Run | | | | | | | | | | | | |
| Pasco | Pasco | PNW So ID NG 2 | 40 | 41 | 42 | 43 | 43 | 42 | 38 | 34 | 34 | 33 | 39 | 39 |
| Pine Products | (out of the mix) | Must Run | | | | | | | | | | | | |
| Pocatello Waste 1 | (lost) | Waste Burner | | | | | | | | | | | | |
| Point Whitehorn 2 | Point Whitehorn 2 | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| Point Whitehorn 3 | Point Whitehorn 3 | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| Potlatch Corp 1-4 | Potlatch Corp. 1-4 | Must Run | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| Prairie Wood Products (Cogen 1) | Prairie Wood Product | Must Run | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Randolph Road 1- 20 | Randolph Road 1- 20 | PNW East NG 6 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| Rathdrum 1 & 2 | Rathdrum 1 & 2 | PNW East NG 6 | 162 | 168 | 172 | 176 | 176 | 174 | 150 | 127 | 124 | 121 | 158 | 158 |
| Rathdrum Power Project | Rathdrum Pwr Proj | PNW East NG 2 | 223 | 231 | 237 | 242 | 242 | 239 | 206 | 174 | 170 | 167 | 217 | 218 |
| River Road 1 | River Road | PNW West NG 1 | 233 | 239 | 245 | 248 | 248 | 246 | 214 | 182 | 179 | 176 | 230 | 230 |
| Rock River | Rock River | Must Run | 17 | 15 | 25 | 31 | 34 | 45 | 11 | 14 | 12 | 10 | 10 | 15 |
| Roosevelt Landfill | Hill | Must Run | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Rupert Cogeneration | Rupert Cogeneration | PNW So ID NG 2 | 8 | 9 | 9 | 9 | 9 | 9 | 8 | 7 | 7 | 7 | 8 | 8 |
| Salmon 1 & 2 | Salmon 1 & 2 | PNW East NG 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| SDS Lumber ST | (unavailable) | Must Run | | | | | | | | | | | | |
| Short Mountain | Short Mountain | Waste Burner | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Simplot Cogen 1 | Simplot Pocatello | PNW East NG 3 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Skagit Co Waste 1 | (retired) | Waste Burner | | | | | | | | | | | | |
| SP Newsprint (Newberg) | SP Newsprint GT | PNW West NG 3 | 86 | 88 | 90 | 91 | 91 | 90 | 82 | 74 | 73 | 72 | 85 | 84 |
| Spokane MSW 1 | Spokane MSW | Waste Burner | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Springfield ICs Phase II | Springfield Ph II | PNW West NG 6 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Stateline | Stateline | Must Run | 156 | 141 | 227 | 286 | 310 | 415 | 98 | 129 | 111 | 93 | 91 | 141 |
| Steam Plant No 2 1 | (retired) | Waste Burner | | | | | | | | | | | | |
| Steam Plant No 2 2 | (retired) | Must Run | | | | | | | | | | | | |
| Sumas Energy 1 | Sumas Energy | PNW West NG 3 | 116 | 119 | 121 | 123 | 123 | 122 | 106 | 90 | 89 | 87 | 114 | 114 |
| Tacoma Landfill | Tacoma Landfill | PNW West NG 6 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Tenaska 1 | Tenaska Washington I | PNW West NG 3 | 231 | 236 | 242 | 245 | 245 | 243 | 211 | 180 | 177 | 174 | 228 | 227 |
| Vaagen Bros 1 | Vaagen Bros Lumber | Must Run | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Valmy 1 | Valmy 1 | Valmy | 127 | 127 | 127 | 127 | 127 | 127 | 107 | 86 | 86 | 86 | 127 | 127 |
| Valmy 2 | Valmy 2 | Valmy | 134 | 134 | 134 | 134 | 134 | 134 | 113 | 91 | 91 | 91 | 134 | 134 |
| Vansycle Ridge | Vansycle | Must Run | 6 | 5 | 9 | 11 | 12 | 16 | 4 | 5 | 4 | 4 | 3 | 5 |
| Wah Chang | (unavailable) | PNW West NG 1 | | | | | | | | | | | | |
| Warm Spgs Forest Products | Warm Springs Forest | Must Run | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| West Boise Waste 1 | (lost) | Must Run | | | | | | | | | | | | |
| West Point Treatment Plant 3 | West Point | Must Run | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Weyco Energy CTR 1 | Weyerhaeuser Springf | Waste Burner | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Whatcom MSW | Whatcom MSW | Waste Burner | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Willamette Industries (Albany) GT U | (unavailable) | PNW West NG 3 | | | | | | | | | | | | |
| Wood Plants 2 | Evergreen Forest Pro | Must Run | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |

**Figure L-69: Existing Resources, Sorted by Name**

| Fuel | Heat Rate | VOM | Unit Name | Alternative name/description | Aggr_Unit | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | BTU/kWh | 2004$/MWh | | | | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) |
| ##55 | 10836 | 1.83 | Boardman 1 | Boardman | Boardman 1 | 556 | 556 | 556 | 556 | 556 | 556 | 467 | 379 | 379 | 379 | 556 | 556 |
| | 9990 | 1.40 | Jim Bridger 1 | Jim Bridger 1 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| | 9990 | 1.40 | Jim Bridger 2 | Jim Bridger 2 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| | 9990 | 1.40 | Jim Bridger 3 | Jim Bridger 3 | Bridger | 177 | 177 | 177 | 177 | 177 | 177 | 149 | 121 | 121 | 121 | 177 | 177 |
| | 9990 | 1.40 | Jim Bridger 4 | Jim Bridger 4 | Bridger | 173 | 173 | 173 | 173 | 173 | 173 | 145 | 118 | 118 | 118 | 173 | 173 |
| ##53 | 10240 | 1.83 | Centralia 1 | Centralia 1 | Centralia | 670 | 670 | 670 | 670 | 670 | 670 | 563 | 456 | 456 | 456 | 670 | 670 |
| ##53 | 10240 | 1.83 | Centralia 2 | Centralia 2 | Centralia | 670 | 670 | 670 | 670 | 670 | 670 | 563 | 456 | 456 | 456 | 670 | 670 |
| | 11170 | 1.30 | Colstrip 1 | Colstrip 1 | Colstrip 1&2 | 307 | 307 | 307 | 307 | 307 | 307 | 258 | 209 | 209 | 209 | 307 | 307 |
| | 11170 | 1.30 | Colstrip 2 | Colstrip 2 | Colstrip 1&2 | 307 | 307 | 307 | 307 | 307 | 307 | 258 | 209 | 209 | 209 | 307 | 307 |
| | 10650 | 1.83 | Colstrip 3 | Colstrip 3 | Colstrip 3&4 | 740 | 740 | 740 | 740 | 740 | 740 | 622 | 504 | 504 | 504 | 740 | 740 |
| | 10650 | 1.83 | Colstrip 4 | Colstrip 4 | Colstrip 3&4 | 740 | 740 | 740 | 740 | 740 | 740 | 622 | 504 | 504 | 504 | 740 | 740 |
| | 11010 | 1.83 | Corrette | J.E. Corrette | Corrette | 160 | 160 | 160 | 160 | 160 | 160 | 134 | 109 | 109 | 109 | 160 | 160 |
| #112 | 5000 | 3.02 | Encogen 1 | Encogen 1-3 | Encogen 1 | 151 | 154 | 158 | 160 | 160 | 159 | 138 | 117 | 115 | 114 | 149 | 148 |
| ###7 | 8000 | 2.15 | Biomass-One 1 | Biomass One | Must Run | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| ###5 | 10064 | 2.15 | Columbia Generating Station | Columbia Generating | Must Run | 1170 | 1170 | 1170 | 1170 | 1170 | 1170 | 944 | 720 | 720 | 720 | 1170 | 1170 |
| | | | Combine Hills I | Combine Hills I | Must Run | 12 | 11 | 17 | 22 | 24 | 32 | 7 | 10 | 8 | 7 | 7 | 11 |
| ##30 | 0 | 1.40 | Condon Wind Project Phase I | Condon 2001 | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| ##30 | 0 | 1.40 | Condon Wind Project Phase II | Condon 2002 | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| ###7 | 8000 | 2.15 | D R Johnson Lumber (Riddle, Coge | Cogen II | Must Run | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| ###7 | 5000 | 2.15 | Everett Cogen 1 | Everett Cogen | Must Run | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| | | | Foote Creek | Foote Creek | Must Run | 17 | 15 | 25 | 31 | 34 | 45 | 11 | 14 | 12 | 10 | 10 | 15 |
| ###7 | 5000 | 2.15 | Georgia Pacific (Camas) | Georgia-Pacific (Cam | Must Run | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 |
| ###7 | 5000 | 2.15 | Georgia Pacific (Wauna) | Georgia-Pacific (Wau | Must Run | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| ###7 | 14380 | 2.15 | Kettle Falls ST | Kettle Falls | Must Run | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| ##30 | 0 | 1.40 | Klondike | Klondike | Must Run | 7 | 6 | 10 | 12 | 14 | 18 | 4 | 6 | 5 | 4 | 4 | 6 |
| ###7 | 12380 | 2.15 | Libby 1 Champion | (retired) | Must Run | | | | | | | | | | | | |
| ###7 | 15476 | 2.15 | Libby 2 Champion | (retired) | Must Run | | | | | | | | | | | | |
| | | | Mariah | Mariah | Must Run | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ##30 | 0 | 1.40 | Nine Canyon | Nine Canyon | Must Run | 14 | 12 | 20 | 25 | 27 | 36 | 9 | 11 | 10 | 8 | 8 | 12 |
| ##30 | 0 | 1.40 | Nine Canyon | Nine Canyon Expansio | Must Run | 4 | 4 | 6 | 8 | 9 | 12 | 3 | 4 | 3 | 3 | 3 | 4 |
| ##30 | 0 | 1.40 | OR RPS/SBC Wind 03 | OR RPS/SBC Wind 03 | Must Run | | | | | | | | | | | | |
| ###7 | 17000 | 2.15 | Pine Products | (out of the mix) | Must Run | | | | | | | | | | | | |
| ###7 | 8000 | 2.15 | Potlatch Corp 1-4 | Potlatch Corp. 1-4 | Must Run | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| ###7 | 5000 | 2.15 | Prairie Wood Products (Cogen 1) | Prairie Wood Product | Must Run | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| | | | Rock River | Rock River | Must Run | 17 | 15 | 25 | 31 | 34 | 45 | 11 | 14 | 12 | 10 | 10 | 15 |
| ###7 | 10000 | 2.15 | Roosevelt Landfill | Hill | Must Run | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| ###7 | 6000 | 2.15 | SDS Lumber ST | (unavailable) | Must Run | | | | | | | | | | | | |
| ##30 | 0 | 1.40 | Stateline | Stateline | Must Run | 156 | 141 | 227 | 286 | 310 | 415 | 98 | 129 | 111 | 93 | 91 | 141 |
| ###7 | 14000 | 2.15 | Steam Plant No 2 2 | (retired) | Must Run | | | | | | | | | | | | |
| ###7 | 8000 | 2.15 | Vaagen Bros 1 | Vaagen Bros Lumber | Must Run | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| ##30 | 0 | 1.40 | Vansycle Ridge | Vansycle | Must Run | 6 | 5 | 9 | 11 | 12 | 16 | 4 | 5 | 4 | 4 | 3 | 5 |
| | | | Warm Spgs Forest Products | Warm Springs Forest | Must Run | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| ###7 | 8000 | 2.15 | West Boise Waste 1 | (lost) | Must Run | | | | | | | | | | | | |
| ###7 | 8000 | 2.15 | West Point Treatment Plant 3 | West Point | Must Run | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| ###7 | 8000 | 2.15 | Wood Plants 2 | Evergreen Forest Pro | Must Run | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| #114 | 6700 | 3.02 | Hermiston Power Project | Hermiston Power | PNW East NG 1 | 581 | 600 | 617 | 629 | 630 | 621 | 536 | 454 | 443 | 435 | 564 | 566 |
| #114 | 6800 | 3.02 | Klamath Cogen Project | Klamath Cogeneration | PNW East NG 1 | 443 | 457 | 470 | 480 | 480 | 473 | 408 | 346 | 337 | 331 | 430 | 432 |
| | | | Goldendale Energy Ce | Goldendale Energy Ce | PNW East NG 2 | 229 | 236 | 243 | 248 | 248 | 245 | 211 | 179 | 174 | 171 | 222 | 223 |
| #114 | 7050 | 3.02 | Hermiston Generating 1 | Hermiston Gen 1 | PNW East NG 2 | 218 | 225 | 231 | 236 | 236 | 233 | 201 | 170 | 166 | 163 | 211 | 212 |
| #114 | 7050 | 3.02 | Hermiston Generating 2 | Hermiston Gen 2 | PNW East NG 2 | 218 | 225 | 231 | 236 | 236 | 233 | 201 | 170 | 166 | 163 | 211 | 212 |
| #114 | 7000 | 3.02 | Rathdrum Power Project | Rathdrum Pwr Proj | PNW East NG 2 | 223 | 231 | 237 | 242 | 242 | 239 | 206 | 174 | 170 | 167 | 217 | 218 |
| #114 | 7050 | 3.02 | Coyote Springs 1 | Coyote Springs 1 | PNW East NG 3 | 208 | 215 | 221 | 226 | 226 | 223 | 192 | 163 | 159 | 156 | 202 | 203 |
| #114 | 6950 | 3.02 | Coyote Springs 2 | Coyote Springs 2 | PNW East NG 3 | 258 | 267 | 274 | 280 | 280 | 276 | 238 | 202 | 197 | 193 | 251 | 252 |
| #120 | 8000 | 3.02 | Glenns Ferry Cogeneration | Glenns Ferry Cogener | PNW East NG 3 | 8 | 9 | 9 | 9 | 9 | 9 | 8 | 7 | 7 | 7 | 8 | 8 |
| #114 | 9500 | 8.62 | Kettle Falls GT | Kettle Falls GT | PNW East NG 3 | 6 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 5 | 5 | 6 | 6 |
| #114 | 8700 | 8.62 | Klamath Expansion (GTs) | (no match) | PNW East NG 3 | | | | | | | | | | | | |
| #120 | 5000 | 3.45 | Simplot Cogen 1 | Simplot Pocatello | PNW East NG 3 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| #114 | 11600 | | Boulder Park | Boulder Park | PNW East NG 6 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| #114 | 10700 | | Finley | Finley | PNW East NG 6 | 25 | 26 | 26 | 27 | 27 | 27 | 24 | 22 | 21 | 21 | 24 | 24 |
| #114 | 11500 | | Morrow Power | Morrow Power | PNW East NG 6 | 23 | 24 | 25 | 25 | 25 | 25 | 21 | 18 | 18 | 17 | 22 | 22 |
| | | | Mountain View | Mountain View | PNW East NG 6 | 148 | 152 | 157 | 160 | 160 | 158 | 136 | 115 | 112 | 110 | 143 | 144 |
| | | | North Side | North Side | PNW East NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| #114 | 10750 | | Northeast | Northeast 1 & 2 | PNW East NG 6 | 62 | 64 | 66 | 67 | 67 | 66 | 57 | 48 | 47 | 46 | 60 | 60 |
| | | | Randolph Road 1- 20 | Randolph Road 1- 20 | PNW East NG 6 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| | | | Rathdrum 1 & 2 | Rathdrum 1 & 2 | PNW East NG 6 | 162 | 168 | 172 | 176 | 176 | 174 | 150 | 127 | 124 | 121 | 158 | 158 |
| | | | Salmon 1 & 2 | Salmon 1 & 2 | PNW East NG 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| ##84 | 13000 | | Boundary GT | (emergency) | PNW Oil | | | | | | | | | | | | |
| ##84 | 11600 | | Grays Harbor ICs | Hoquiam 1 - 5 | PNW Oil | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| ##84 | 11600 | | Okanogan Co PUD ICs Ph 2 | Okanogan Co. PUD ICs | PNW Oil | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| #120 | 12100 | | Danskin | Danskin (Evander And | PNW So ID NG 2 | 83 | 86 | 88 | 90 | 90 | 89 | 77 | 65 | 63 | 62 | 81 | 81 |
| #114 | 11500 | | Pasco | Pasco | PNW So ID NG 2 | 40 | 41 | 42 | 43 | 43 | 42 | 38 | 34 | 34 | 33 | 39 | 39 |
| #120 | 8000 | 3.02 | Rupert Cogeneration | Rupert Cogeneration | PNW So ID NG 2 | 8 | 9 | 9 | 9 | 9 | 9 | 8 | 7 | 7 | 7 | 8 | 8 |
| | | | Boise Cascade Medfor | Boise Cascade Medfor | PNW West NG 1 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| #112 | 7000 | 3.02 | Frederickson Power 1 | Frederickson Power ( | PNW West NG 1 | 259 | 265 | 271 | 275 | 275 | 273 | 237 | 202 | 198 | 195 | 255 | 255 |
| #112 | 7000 | 3.02 | River Road 1 | River Road | PNW West NG 1 | 233 | 239 | 245 | 248 | 248 | 246 | 214 | 182 | 179 | 176 | 230 | 230 |
| #112 | 5800 | 3.45 | Wah Chang | (unavailable) | PNW West NG 1 | | | | | | | | | | | | |
| #112 | 7200 | 3.02 | Big Hanaford | Big Hanaford | PNW West NG 3 | 233 | 239 | 245 | 248 | 248 | 246 | 214 | 182 | 179 | 176 | 230 | 230 |
| #112 | 7000 | 3.02 | Chehalis Generation Facility | Chehalis Generating | PNW West NG 3 | 489 | 501 | 513 | 519 | 520 | 515 | 448 | 381 | 375 | 369 | 483 | 482 |
| | | | March Point 1&2 | March Point | PNW West NG 3 | 132 | 135 | 138 | 140 | 140 | 139 | 121 | 103 | 101 | 99 | 130 | 130 |
| #112 | 5500 | 8.62 | SP Newsprint (Newberg) | SP Newsprint GT | PNW West NG 3 | 86 | 88 | 90 | 91 | 91 | 90 | 82 | 74 | 73 | 72 | 85 | 84 |
| #112 | 8000 | 3.02 | Sumas Energy 1 | Sumas Energy | PNW West NG 3 | 116 | 119 | 121 | 123 | 123 | 122 | 106 | 90 | 89 | 87 | 114 | 114 |
| #112 | 7700 | 3.02 | Tenaska 1 | Tenaska Washington I | PNW West NG 3 | 231 | 236 | 242 | 245 | 245 | 243 | 211 | 180 | 177 | 174 | 228 | 227 |
| #112 | 5500 | 8.62 | Willamette Industries (Albany) GT U | (unavailable) | PNW West NG 3 | | | | | | | | | | | | |
| #112 | 9200 | 3.02 | Beaver 1-7 | Beaver | PNW West NG 5 | 475 | 487 | 498 | 504 | 505 | 500 | 435 | 370 | 364 | 359 | 469 | 468 |
| #112 | 11500 | | Beaver 8 | Beaver 8 | PNW West NG 6 | 23 | 23 | 24 | 24 | 24 | 24 | 22 | 20 | 19 | 19 | 22 | 22 |
| | | | Crystal Mountain 1 & | Crystal Mountain 1 & | PNW West NG 6 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| | | | Eastsound 4 & 5 | Eastsound 4 & 5 | PNW West NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| #112 | 10600 | | Frederickson 1 | Frederickson (PSE) | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| #112 | 10600 | | Frederickson 2 | Frederickson (PSE) | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| #112 | 10711 | | Fredonia 1 | Fredonia 1 | PNW West NG 6 | 117 | 120 | 122 | 124 | 124 | 123 | 107 | 91 | 89 | 88 | 115 | 115 |
| #112 | 10711 | | Fredonia 2 | Fredonia 2 | PNW West NG 6 | 117 | 120 | 122 | 124 | 124 | 123 | 107 | 91 | 89 | 88 | 115 | 115 |
| #112 | 10300 | | Fredonia 3 | Fredonia 3 | PNW West NG 6 | 57 | 59 | 60 | 61 | 61 | 60 | 55 | 50 | 49 | 48 | 57 | 57 |
| #112 | 10300 | | Fredonia 4 | Fredonia 4 | PNW West NG 6 | 57 | 59 | 60 | 61 | 61 | 60 | 55 | 50 | 49 | 48 | 57 | 57 |
| | | | MEAD | MEAD | PNW West NG 6 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| #112 | 10600 | | Point Whitehorn 2 | Point Whitehorn 2 | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| #112 | 10600 | | Point Whitehorn 3 | Point Whitehorn 3 | PNW West NG 6 | 84 | 86 | 88 | 89 | 89 | 88 | 77 | 65 | 64 | 63 | 83 | 83 |
| #112 | 11600 | | Springfield ICs Phase II | Springfield Ph II | PNW West NG 6 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| | | | Tacoma Landfill | Tacoma Landfill | PNW West NG 6 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| #112 | 11500 | | Bailey (Clatskanie GT) | Alden Bailey | PNW West NG 7 | 10 | 11 | 11 | 11 | 11 | 11 | 10 | 9 | 9 | 9 | 10 | 10 |
| #112 | 13000 | | BP (Cherry Point) GTs | BP Cherry Point GTs | PNW West NG 7 | 69 | 70 | 72 | 73 | 73 | 72 | 66 | 59 | 59 | 58 | 68 | 68 |
| #112 | 13000 | | Equilon GTs | Equilon GTs | PNW West NG 7 | 37 | 38 | 38 | 39 | 39 | 39 | 35 | 32 | 31 | 31 | 36 | 36 |
| #112 | 13000 | | Georgia-Pacific (Bellingham) GTs | Georgia-Pacific (Bel | PNW West NG 7 | 9 | 10 | 10 | 10 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 |
| | | | ICT PP&L/Utah&Wyo to | ICT PP&L/Utah&Wyo to | Valmy | 184 | 160 | 168 | 154 | 187 | 187 | 178 | 171 | 189 | 265 | 296 | 253 |
| | 10030 | 1.83 | Valmy 1 | Valmy 1 | Valmy | 127 | 127 | 127 | 127 | 127 | 127 | 107 | 86 | 86 | 86 | 127 | 127 |
| | 10030 | 1.83 | Valmy 2 | Valmy 2 | Valmy | 134 | 134 | 134 | 134 | 134 | 134 | 113 | 91 | 91 | 91 | 134 | 134 |
| ###6 | 8000 | 2.15 | Coffin Butte 1 | Coffin Butte | Waste Burner | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| ###7 | 17000 | 2.15 | Frontier Energy | (no match) | Waste Burner | | | | | | | | | | | | |
| ###6 | 8000 | 2.15 | Marion Solid Waste 1 | Covanta Marion | Waste Burner | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| ###7 | 8000 | 2.15 | Pocatello Waste 1 | (lost) | Waste Burner | | | | | | | | | | | | |
| | | | Short Mountain | Short Mountain | Waste Burner | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| ###6 | 8000 | 2.15 | Skagit Co Waste 1 | (retired) | Waste Burner | | | | | | | | | | | | |
| ###6 | 8000 | 2.15 | Spokane MSW 1 | Spokane MSW | Waste Burner | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| ###7 | 14000 | 2.15 | Steam Plant No 2 1 | (retired) | Waste Burner | | | | | | | | | | | | |
| ###6 | 12500 | 2.15 | Weyco Energy CTR 1 | Weyerhaeuser Springf | Waste Burner | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| | | | Whatcom MSW | Whatcom MSW | Waste Burner | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |

**Figure L-70: Existing Resources, Sorted by Aggregate Unit**

| Name | Heatrate | Fuel | FOR | FOR Stochastic | VOM | Sep-Nov | Dec-Feb | Mar-May | Jun-Aug |
|---|---|---|---|---|---|---|---|---|---|
| | kBTU/kWh | 2004$/MWh | | | 2004$/MWh | (MW) | (MW) | (MW) | (MW) |
| Boardman 1 | 10.836 | $1.20/MMBTU | 0.07 | TRUE | 1.83 | 556.0 | 556.0 | 408.3 | 497.0 |
| Bridger | 9.990 | $0.89/MMBTU | 0.07 | TRUE | 1.40 | 704.0 | 704.0 | 518.0 | 629.7 |
| CCCT | 7.270 | PNW East NG_006 | 0.05 | FALSE | 3.11 | 610.0 | 610.0 | 610.0 | 610.0 |
| Centralia | 10.240 | $1.82/MMBTU | 0.07 | TRUE | 1.83 | 1340.0 | 1340.0 | 983.3 | 1197.3 |
| Coal | 9.550 | $1.00/MMBTU | 0.07 | FALSE | 1.94 | 400.0 | 400.0 | 400.0 | 400.0 |
| Colstrip 1&2 | 11.170 | $0.78/MMBTU | 0.07 | TRUE | 1.30 | 614.0 | 614.0 | 450.7 | 548.7 |
| Colstrip 3&4 | 10.650 | $1.00/MMBTU | 0.07 | TRUE | 1.83 | 1480.0 | 1480.0 | 1086.7 | 1322.7 |
| Consv_LO | 0.000 | (none) | 0.00 | FALSE | | | | | |
| Consv_NLO | 0.000 | (none) | 0.00 | FALSE | | | | | |
| Contracts | 0.000 | (none) | 0.00 | FALSE | | | | | |
| Corrette | 11.010 | $1.00/MMBTU | 0.07 | FALSE | 1.83 | 160.0 | 160.0 | 117.3 | 143.0 |
| Encogen 1 | 5.005 | Waste | 0.07 | FALSE | 3.02 | 154.3 | 159.7 | 123.3 | 137.0 |
| Hydro | 0.000 | (none) | 0.00 | FALSE | | | | | |
| Hydro Commercial | 0.000 | (none) | 0.00 | FALSE | | | | | |
| Must run | 0.000 | (none) | 0.05 | FALSE | 0.00 | 1699.7 | 1956.3 | 1227.0 | 1444.7 |
| PNW East NG 1 | 6.743 | PNW East NG_006 | 0.05 | TRUE | 3.02 | 1056.0 | 1104.3 | 841.3 | 919.3 |
| PNW East NG 2 | 7.032 | PNW East NG_006 | 0.05 | TRUE | 3.02 | 915.7 | 958.0 | 729.3 | 796.7 |
| PNW East NG 3 | 7.050 | PNW East NG_006 | 0.07 | FALSE | 3.02 | 504.3 | 527.7 | 404.7 | 440.3 |
| PNW East NG 6 | 10.603 | PNW East NG_006 | 0.07 | FALSE | 3.02 | 495.3 | 515.3 | 408.7 | 438.7 |
| PNW So ID NG 2 | 11.741 | PNW So ID NG_004 | 0.00 | FALSE | 3.02 | 135.3 | 141.3 | 111.0 | 119.3 |
| PNW West NG 1 | 6.968 | PNW West NG A_006 | 0.07 | FALSE | 3.02 | 512.0 | 529.7 | 412.0 | 455.0 |
| PNW West NG 3 | 7.337 | PNW West NG A_006 | 0.05 | TRUE | 3.02 | 1318.0 | 1362.7 | 1062.0 | 1171.3 |
| PNW West NG 5 | 9.200 | PNW West NG A_006 | 0.05 | TRUE | 3.02 | 486.7 | 503.0 | 389.7 | 432.0 |
| PNW West NG 6 | 10.637 | PNW West NG A_006 | 0.05 | TRUE | 3.02 | 741.0 | 764.3 | 606.0 | 663.3 |
| PNW West NG 7 | 12.879 | PNW West NG A_006 | 0.07 | FALSE | 8.62 | 128.3 | 132.7 | 111.7 | 117.3 |
| SCCT | 9.810 | PNW East NG_006 | 0.07 | FALSE | 8.65 | 100.0 | 100.0 | 100.0 | 100.0 |
| Valmy | 10.030 | $1.00/MMBTU | 0.07 | FALSE | 1.83 | 431.7 | 437.0 | 370.7 | 504.3 |
| Waste Burner | 4.000 | Waste | 0.10 | TRUE | | 55.0 | 55.0 | 55.0 | 55.0 |
| Wind | 0.000 | (none) | 0.70 | FALSE | 1.06 | 100.0 | 100.0 | 100.0 | 100.0 |
| Wind - MT | 0.000 | (none) | 0.64 | FALSE | 1.06 | 100.0 | 100.0 | 100.0 | 100.0 |

**Figure L-71: Surrogate Plant Characteristics**


**Figure L-72: Thermal Resource UDF References**

## System Benefit Charge Wind

Senate bill 1149, the state of Oregon's 1999 electric power restructuring legislation, established a "system benefit charge" which funds conservation and renewable development. Other states have looked at establishing similar reserves. Those responsible for renewables development have identified a preliminary system benefit charge (SBC) wind development schedule for the next 10 years. The regional model does not find that wind technology will be cost effective until the next decade, but SBC wind is included in the regional models baseline set of resources in the "must run" surrogate. SBC wind is one of very few future resources included in the baseline. It is included in part because it appears certain the region is proceeding with the development of this wind. It is included in part because the Council recognizes the importance of developing experience with this resource before it becomes a major resource for the region. The recommended plan relies heavily on commercially competitive wind generation after 2010.

The amount of SBC wind in the regional model's baseline appears in Figure L-73 [**11**]. Although the table extends only through 2014, these availabilities extend indefinitely in the regional model. Apart from the capacity duration forced outage rate assigned to the must run surrogate plant in the regional model, the model does not reflect the potentially complex forced outage nature of this resource.

| Wind MWa | 1st Mo | | | |
|---|---|---|---|---|
| Hydro Year | sep | dec | mar | jun |
| 2004 | | 17.5 | 20.3 | 19.7 |
| 2005 | 15.3 | 31.9 | 45.2 | 43.9 |
| 2006 | 34.0 | 53.9 | 71.0 | 68.9 |
| 2007 | 53.4 | 76.9 | 98.1 | 95.2 |
| 2008 | 73.8 | 101.8 | 128.0 | 124.1 |
| 2009 | 96.3 | 130.8 | 163.4 | 158.5 |
| 2010 | 122.9 | 167.6 | 209.7 | 203.4 |
| 2011 | 157.7 | 216.3 | 271.2 | 263.1 |
| 2012 | 204.0 | 284.7 | 359.3 | 348.5 |
| 2013 | 270.2 | 309.9 | 359.3 | 348.5 |
| 2014 | 270.2 | 309.9 | 359.3 | 348.5 |

**Figure L-73: SBC Capability, by Hydro Year**

## Independent Power Producers

The PNUCC Northwest Regional Forecast identifies approximately 3200 average megawatts of IPP generation (3500 MW capacity) that is not under contract to Northwest load. Most of the generation is in the form of gas-fired combined cycle combustion turbines located in Washington and Oregon, much of that west of the Cascades. The 1300 MW Centralia coal-fired power plant located in western Washington is also part of that sum. The Council also surveyed the independent power producers of the region through the Northwest Independent Power Producers Coalition (NIPPC). NIPPC identify 3600 MW (capacity) in Oregon and Washington. Of that, approximately 1400 MW (capacity) is under contract through 2005, 950 MW is under contract through 2008, and 4300 MW is under contract beyond 2008. NIPPC noted, "... Virtually all IPP capacity is, as a result of transmission constraints and by design, committed exclusively to the Northwest."

The Council regards the IPP contribution to the wholesale electricity market significant, both in terms of power and of price stability. The Council chose to model the availability of this IPP generation in the market explicitly. Indeed, the Council considered the alternative of modeling ownership purchase or long-term contracts with IPP generators. They discarded this approach, however, because the region has no way of knowing what contract terms parties might eventually enter into through bilateral purchase or contract negotiation.

Although the energy from IPP generation contributes to the region's energy balance, and therefore affects price through the RRP algorithm, the value of these resources does not offset market purchases. Specifically, the energy is included in the system energy requirement calculation in cell {AQ676} of the sample workbook. When the surrogate plant is valued in the market, however, that portion of the surrogate's value associated with IPP generation does not contribute. A more concrete example of this follows.

Figure L-74 identifies regional IPP ownership [**12**]. The first column identifies the percentage of each plant under contract to meet regional load. The second column identifies to which surrogate plant each IPP unit is aggregated. To determine what fraction of the surrogate plant's capacity and value contribute to the region's portfolio, the seasonal availabilities are multiplied by the contract percentages and summed by surrogate plant. The original surrogate availabilities appear in Figure L-75. These availabilities contribute to the resource-load energy balance of the region. The seasonal availabilities meeting regional load appear in Figure L-76. These determine the amount of economic value the region gets. The fraction of each surrogate unit that contributes value to the region appears in the column on the right hand side of Figure L-76.

| Contracted | Aggr_Unit | Unit Name | FoundinFazio | Location | Fall | Winter | Spring | Summer |
|---|---|---|---|---|---|---|---|---|
| 0% | Centralia 2 | Centralia 2 | Centralia 2 | PNW West | 670 | 670 | 492 | 599 |
| 0% | Centralia 1 | Centralia 1 | Centralia 1 | PNW West | 670 | 670 | 492 | 599 |
| 0% | PNW East NG 1 | Hermiston Power Project | Hermiston Pow | PNW East | 599 | 627 | 478 | 522 |
| 21% | PNW East NG 1 | Klamath Cogen Project | Klamath Coger | | 457 | 478 | 364 | 398 |
| 100% | PNW West NG 1 | Frederickson Power 1 | Frederickson F | | 265 | 274 | 212 | 235 |
| 0% | PNW East NG 2 | Goldendale Energy Ce | Goldendale Energy Ce | | 236 | 247 | 188 | 205 |
| 100% | PNW East NG 2 | Hermiston Generating 1 | Hermiston Ger | PNW East | 225 | 235 | 179 | 195 |
| 100% | PNW East NG 2 | Hermiston Generating 2 | Hermiston Ger | PNW East | 225 | 235 | 179 | 195 |
| 0% | PNW East NG 2 | Rathdrum Power Project | Rathdrum Pwr | PNW East | 230 | 241 | 183 | 201 |
| 0% | PNW West NG 3 | Chehalis Generation Fac | Chehalis Gene | | 501 | 518 | 401 | 445 |
| 0% | PNW West NG 3 | Big Hanaford | Big Hanaford | PNW West | 239 | 247 | 192 | 212 |
| 100% | PNW West NG 3 | March Point 1 | March Point | PNW West | 135 | 140 | 108 | 120 |
| 100% | PNW West NG 3 | Sumas Energy 1 | Sumas Energy | PNW West | 119 | 123 | 95 | 105 |
| 100% | PNW West NG 3 | Tenaska 1 | Tenaska Wash | PNW West | 236 | 244 | 189 | 210 |
| 100% | PNW East NG 3 | Coyote Springs 2 | Coyote Springs | PNW East | 266 | 279 | 212 | 232 |
| 0% | PNW East NG 3 | Klamath Expansion (GTs | (no match) | | 0 | 0 | 0 | 0 |
| 0% | PNW East NG 6 | Morrow Power | Morrow Power | PNW East | 24 | 25 | 19 | 20 |

**Figure L-74: IPP Capabilities**

| Orginal | Fall | Winter | Spring | Summer | Average |
|---|---|---|---|---|---|
| Centralia | 1340.0 | 1340.0 | 983.3 | 1197.3 | 1215 |
| PNW East NG 1 | 1056.0 | 1104.3 | 841.3 | 919.3 | 980 |
| PNW West NG 1 | 512.0 | 529.7 | 412.0 | 455.0 | 477 |
| PNW East NG 2 | 915.7 | 958.0 | 729.3 | 796.7 | 850 |
| PNW West NG 3 | 1318.0 | 1362.7 | 1062.0 | 1171.3 | 1229 |
| PNW East NG 6 | 741.0 | 764.3 | 606.0 | 663.3 | 694 |
| | 5883 | 6059 | 4634 | 5203 | 5445 |

**Figure L-75: Surrogate Capabilities, including IPPs**

| Final | Fall | Winter | Spring | Summer | Average | Amt of Value to use |
|---|---|---|---|---|---|---|
| Centralia | 0.0 | 0.0 | 0.0 | 0.0 | 0 | 0% |
| PNW East NG 1 | 96 | 100 | 76 | 84 | 89 | 9% |
| PNW West NG 1 | 512.0 | 529.7 | 412.0 | 455.0 | 477 | 100% |
| PNW East NG 2 | 449 | 470 | 358 | 391 | 417 | 49% |
| PNW West NG 3 | 578.0 | 597.3 | 469.0 | 514.7 | 540 | 44% |
| PNW East NG 6 | 717 | 739 | 587 | 643 | 672 | 97% |
| | 2352 | 2437 | 1902 | 2087 | 2195 | |

**Figure L-76: Surrogate Capabilities, without IPPs**

To see a specific example of how these fractions are applied, consider the on-peak values for the surrogate plant "PNW West NG 3 006" which appear in row {429}. Recall from the discussion of valuation costing and of the thermal dispatch UDF that value is the negative cost appearing in this row. The formula in cell {CV429} discounts these values to the first period:

=0.434512325830654*8760/8064*NPV(0.00985340654896882,$R429:$CS429)*
(1+0.00985340654896882)

Comparing this formula to those described in section "Present Value Calculation," page L-79, we note that this formula has an additional leading coefficient of about 43.45%. This corresponds to the fraction identified on the far right hand side of Figure L-76.

Several of the Council members expressed interest in the impact that contracts for the export of firm energy outside the region might have on model results. A detailed discussion of the impacts appears in Appendix P[32] and in reference [**13**]. To summarize, the impact of such firm contracts would be nil. Of course, firm contract might reduce the pool of counterparties with whom regional utilities could deal. There would be no effect, however, on the market prices, upon which these LSEs are dependent for any unmet requirements.

## New Resources

The new resources in the regional model

- CCCT
- SCCT
- coal plant
- IGCC
- demand response
- wind

are based on corresponding resources in the Council's Aurora model [**14**]. Figure L-77 and Figure L-78 summarize these. (The values in these figures are from the model runs for the final plan. Values in the example workbook and in examples appearing elsewhere in this appendix may differ.)

| | Expected FOR | Stochastic FOR | Variable_Cost ($/MWh): VOM | Fuel Set (ID) | Heatrate (kBTU/kWh) |
|---|---|---|---|---|---|
| **CCCT** | 0.05 | FALSE | 3.11 | PNW East NG | 7.270 |
| **SCCT** | 0.07 | FALSE | 8.65 | PNW East NG | 9.810 |
| **Coal Plant** | 0.07 | FALSE | 1.94 | Coal_003 | 9.550 |
| **IGCC** | 0.10 | FALSE | 1.66 | Coal_003 | 7.790 |
| **Demand Response** | 0.00 | FALSE | 0.00 | (none) | (none) |
| **Wind 1** | 0.00 | FALSE | 1.06+PTC+GT+Integration(Cap) | (none) | (none) |
| **Wind 2** | 0.00 | FALSE | 1.06+PTC+GT+Integration(Cap) | (none) | (none) |

**Figure L-77: New Resource Parameters (1/2)**

The section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65, describes the parameters in Figure L-78. Reference [**15**] documents the calculation of these values. In addition to the parameters discussed in that section, a column calculating the real levelized $2004 per kilowatt year has been added to the far right hand side of Figure L-78 for reference.

[32] See "Independent Power Producers," in the Appendix P chapter, "Sensitivity Studies."

| | Criterion | Index | Planning_Periods | Optional_Construction_Periods | Committed_Construction_Periods | Planning_Costs (RL $M/MWPeriod^2) | Mothball_Costs (RL $M/MWPeriod^2) | Cancellation_Costs (RL $M/MWPeriod^2) | Construction_Costs (RL $M/MWPeriod^2) | CancelThreshold | Const Cost Escl (.01=1%/period) | Annual Escl | ResourceLife (periods | OptionLife (periods | PermitMarketAdds (T/F) | PlannedPlanning_Costs | RLL 2004$/kWyr |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CCCT** | R-L, then cost | 0 | 0 | 4 | 4 | 0 | 0.00029 | 0.01168 | 0.00292 | -99999 | -0.086% | -0.34% | 80 | 20 | FALSE | 0.00149 | 108.0 |
| **SCCT** | R-L, then cost | 1 | 0 | 0 | 4 | 0 | 0.00055 | 0.02185 | 0.00546 | -99999 | -0.100% | -0.40% | 80 | 20 | FALSE | 0.00044 | 96.8 |
| **Coal Plant** | R-L, then cost | 2 | 0 | 5 | 9 | 0 | 0.00034 | 0.01355 | 0.00339 | -99999 | 0.018% | 0.07% | 80 | 20 | FALSE | 0.00048 | 208.1 |
| **IGCC** | R-L, then cost | 2 | 0 | 8 | 8 | 0 | 0.00033 | 0.01310 | 0.00328 | -99999 | -0.116% | -0.46% | 80 | 20 | FALSE | 0.00107 | 232.3 |
| **Demand Response** | fixed | 3 | 0 | 0 | 1 | 0 | 0.00005 | 0.00200 | 0.00050 | -99999 | 0.000% | 0.00% | 80 | 80 | FALSE | 0.00002 | 2.3 |
| **Wind 1** | R-L, then cost | 4 | 0 | 2 | 2 | 0 | 0.00074 | 0.02970 | 0.00743 | -99999 | -0.430% | -1.71% | 80 | 80 | FALSE | 0.00061 | 131.7 |
| **Wind 2** | R-L, then cost | 5 | 0 | 2 | 2 | 0 | 0.00166 | 0.06623 | 0.01656 | -99999 | -0.179% | -0.71% | 80 | 80 | FALSE | 0.00135 | 293.7 |

**Figure L-78: New Resource Parameters (2/2)**

The CCCT, SCCT, Coal, IGCC, and demand response plants use the calculations described in sections "Thermal Generation" and "New Resources, Capital Costs, and Planning Flexibility" to determine costs[33]. While wind plants use the techniques described in the latter section for capital costs calculations, the variable cost calculation is different from that of the other new resources.

The variable cost for wind consists of four parts: variable operations and maintenance (VOM), green tag credit (GTC), production tax credit (PTC), and integration cost (IC). The VOM and IC increase cost; GTC and PTC decrease cost. The history of the PTC and GTC appear in Chapter 6 of the plan. The GTC and PTC are essentially aspects of the future, and Appendix P therefore covers their derivation. VOM is deterministic and IC is a function of wind deployment. This section therefore limits itself to how IC works and how the cost of wind incorporates these various cost components.

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

In the example worksheet, the cells {AQ509} and {AQ510}, which compute the wind capacity and cost of capacity, use the same new capacity UDFs as the other resources, as just mentioned:

=lfPFCap(AP$314,AP$46,$P509)

[33] The model represents demand response as a combustion turbine with a fixed $150/MWh dispatch cost. When better information is available for describing the supply curve of regional demand response, the Council will enhance this representation. Also, while implementation uses the planning flexibility logic, the plan is fixed. Given the uncertainty surrounding the cost and availability of this resource, the Council elected to hold the plan for DR constant in all simulations.

=sfPFCost(AQ509,AP$46,$P509)

The energy (cell {AQ511}) is the capacity (MW) times the capacity factor times the number of on-peak hours in a standard quarter:

=AQ509*1152*0.3

The cost of wind (cell {AQ512}) in millions of 2004 dollars is

=AQ$511*(AQ$506-AQ$204)/1000000

Here the reader will recognize the now familiar valuation formula for costs, the energy times the value of the energy in the market. The on-peak price of electricity is in cell {AQ$204} and cell {AQ$506} contains the variable costs.

During the preparation of the final plan, the calculation of the variable costs change from what is in the sample workbook. This description will first explain the old logic in the sample worksheet. It will then explain how the new logic in the final plan works.

The sample workbook, the GTC and PTC went away completely with the advent of any carbon penalty. Moreover, the IC was $4.00/MWh for 2500 MW or less of wind and $8.00/MWh otherwise. The variable cost in cell {AQ$506} contains the formula

=IF(AQ74=0,AQ79+AQ505+AQ80+AQ81*(1+$R$78*AQ$46/80),AQ505+AQ80)

This formula is testing whether there is a tax for carbon. If so, the variable costs are the sum of the integration charge (cell {AQ505}) and the variable O&M in cell {AQ80}. The integration cost, in turn is given in cell

=IF(AP509+AP519>2500,2*$R$77,$R$77)

As we might expect, the integration cost formula merely doubles the $4.00/MWh in cell {$R$77} if the sum of the capacities for the wind plants exceeds 2500 MW.

If there is no carbon tax, then to these two terms the model adds the PTC (cell {AQ79}) and the GTC. The GTC has the formula

AQ81*(1+$R$78*AQ$46/80)

This simply changes the GTC linearly over time. Depending on the future, the GTC in the draft plan always started out at $6.66 (2004$) and increased or decreased linearly over time.

In the revised logic that the final plan employs, the situation is a bit more complicated. The GTC and PTC are relatively large, and several parties commented that it seemed unreasonable that these would disappear if even the smallest carbon tax occurred. The Council agreed. To make the behavior more realistic, the Council decided that PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains [34]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range. A complete description of the regional model's treatment of GTC and PTC appear in the Appendix P chapter, "Uncertainties."

[34] 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.

In the workbook, the variable cost formula is now

=AQ505+AQ82-AQ81-AQ83

The VOM in cell AQ82 of the new workbook is still fixed, and the integration cost in cell AQ505 is similar to the test described as above. The other two components, however, are more interactive with the carbon tax and the model treats them strictly as elements of the model future. Appendix P therefore describes those worksheet formulas.

## Supply Curves

The portfolio model employs supply curves to represent conservation and price response hydro. This section describes data that the model uses, and it explains some of the choices and considerations behind these representations. During the Council's early modeling efforts, an unexpected relationship emerged between the shape of the supply curve and the value of conservation under uncertain market prices. This appendix describes those discoveries in section "Conservation Value Under Uncertainty," beginning on page L-129.

This section begins with a description of energy allocation for conservation across the on- and off-peak periods. The allocation pertains to both lost opportunity and discretionary conservation.

### Energy Allocation

Figure L-79 illustrates the assumed conservation energy allocation by month [**16**]. Because these are percentages of annual energy, instead of power rates (MW), both the rate of usage and the number of hours in each subperiod influence the values. The regional model, which uses standard periods and power rates, requires the restatement of these percentages.

| | High Load | Low Load |
|---|---|---|
| Jan | 7.7% | 1.9% |
| Feb | 7.1% | 1.7% |
| Mar | 7.5% | 1.5% |
| Apr | 7.0% | 1.6% |
| May | 6.2% | 1.3% |
| Jun | 5.5% | 2.0% |
| Jul | 5.8% | 1.5% |
| Aug | 6.0% | 1.2% |
| Sep | 5.6% | 1.3% |
| Oct | 7.0% | 2.0% |
| Nov | 6.9% | 1.8% |
| Dec | 7.6% | 2.1% |
| Jan | 7.7% | 1.9% |
| Feb | 7.1% | 1.7% |

**Figure L-79: Energy by Month**

| 2005 | High Load | Low Load | Total |
|---|---|---|---|
| Jan | 416 | 328 | 744 |
| Feb | 384 | 288 | 672 |
| Mar | 432 | 312 | 744 |
| Apr | 416 | 304 | 720 |
| May | 416 | 328 | 744 |
| Jun | 416 | 304 | 720 |
| Jul | 416 | 328 | 744 |
| Aug | 432 | 312 | 744 |
| Sep | 416 | 304 | 720 |
| Oct | 416 | 328 | 744 |
| Nov | 416 | 304 | 720 |
| Dec | 432 | 312 | 744 |
| | | | 8760 |

| | on-peak | off-peak | |
|---|---|---|---|
| Sp | 1232 | 928 | 2160 |
| Sum | 1248 | 936 | 2184 |
| Fall | 1264 | 944 | 2208 |
| Win | 1264 | 944 | 2208 |
| | | | 8760 |

**Figure L-80: Typical Hours Per Year and Hydro Quarter**

Using the assumptions in Figure L-80, which represent a typical year, we obtain the average power by hydro quarter by subperiod in Figure L-81:

MW=MWh/hrs

There is significant difference in the weightings for on-and off peak power, but the seasonal variations in these factors is relatively small. To simplify calculations, the model uses the average of the seasonal values, which appear in Figure L-81. These averages are the constants to which the section "Conservation" (page L-44) and other sections refer.

| | on-peak | off-peak |
|---|---|---|
| Sp | 1.48 | 0.42 |
| Sum | 1.22 | 0.44 |
| Fall | 1.35 | 0.46 |
| Win | 1.55 | 0.53 |
| average | 1.402 | 0.465 |

**Figure L-81: Relative Power Rates**

## Lost Opportunity Conservation

As explained in Chapter 3, lost opportunity conservation arises from new building construction and similar situations. While current codes and standards capture a significant amount of lost opportunity conservation, these effects are already captured in the "frozen efficiency" load forecast. That is, the frozen efficiency load forecast incorporates the effects of existing codes and standards on *future* growth in requirements. The lost opportunity conservation in the regional model's supply curves is therefore *new, incremental* conservation. Much of the potential for lost opportunity conservation comes from the advent of new technology.

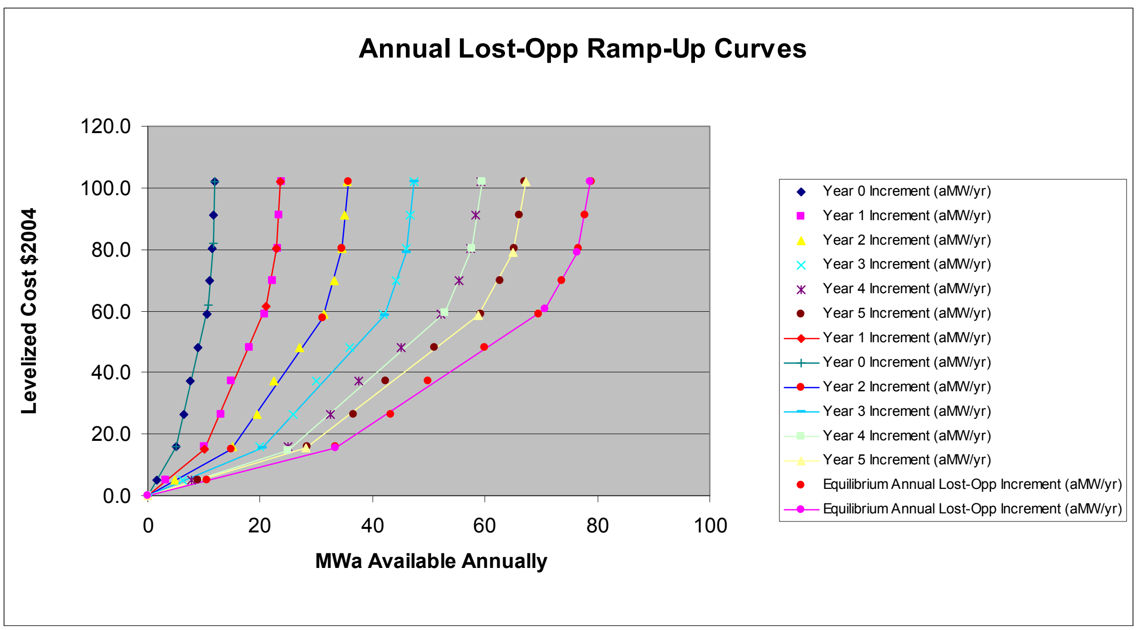



**Figure L-82: Lost Opportunity Supply Curves**

The regional model captures the development of new lost opportunity conservation technology through a sequence of supply curves that reflect increasing potential over time at each price point. This set of supply curves appears in Figure L-82, and the corresponding data appear in Figure L-83 [**17**]. At the bottom of Figure L-83, the reader will find the corresponding representation that the regional portfolio model uses. All supply curves reflect 5.5 mills per kilowatt-hour T&D credit and credit for any benefits unrelated to electric energy efficiency improvement.

In Figure L-83, six years pass before conservation achieves a mature level of potential. This mature level of potential is 85 percent of the theoretical potential. The Council recognizes that the even under the most optimistic conditions, the region will not be able to develop all conservation. Moreover, the rate of development is even more gradual in the regional model than this figure suggests. Instead of one year between supply curves, the regional model assumes two years, and no conservation commences before December of calendar year 2004. For lost opportunity, therefore, the first supply curve applies to the one year period after December 2004, the next supply curve applies to December 2005 up to December 2007, and the remaining supply curves apply every second year through December 2015, when potential reaches maturity.

| Annual Energy (Q) | Year 0 Increment (aMW/yr) | Year 1 Increment (aMW/yr) | Year 2 Increment (aMW/yr) | Year 3 Increment (aMW/yr) | Year 4 Increment (aMW/yr) | Year 5 Increment (aMW/yr) | Equilibrium (aMW/yr) |
|---|---|---|---|---|---|---|---|
| Point 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Point 2 | 5.06 | 10 | 14.9 | 20.3 | 25 | 28.1 | 33.5 |
| Point 3 | 10.8 | 21.1 | 31.2 | 42.2 | 52.8 | 58.8 | 70.6 |
| Point 4 | 11.6 | 22.9 | 34.6 | 45.9 | 57.7 | 65 | 76.5 |
| Point 5 | 11.9 | 23.6 | 35.6 | 47.4 | 59.4 | 67.2 | 78.8 |

| Quarterly Energy (Q) | Year 0 Increment (aMW/yr) | Year 1 Increment (aMW/yr) | Year 2 Increment (aMW/yr) | Year 3 Increment (aMW/yr) | Year 4 Increment (aMW/yr) | Year 5 Increment (aMW/yr) | Equilibrium (aMW/yr) |
|---|---|---|---|---|---|---|---|
| Point 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Point 2 | 1.265 | 2.5 | 3.725 | 5.075 | 6.25 | 7.025 | 8.375 |
| Point 3 | 2.7 | 5.275 | 7.8 | 10.55 | 13.2 | 14.7 | 17.65 |
| Point 4 | 2.9 | 5.725 | 8.65 | 11.475 | 14.425 | 16.25 | 19.125 |
| Point 5 | 2.975 | 5.9 | 8.9 | 11.85 | 14.85 | 16.8 | 19.7 |

| Price (P) | Year 0 Increment (aMW/yr) | Year 1 Increment (aMW/yr) | Year 2 Increment (aMW/yr) | Year 3 Increment (aMW/yr) | Year 4 Increment (aMW/yr) | Year 5 Increment (aMW/yr) | Equilibrium (aMW/yr) |
|---|---|---|---|---|---|---|---|
| Point 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Point 2 | 15.8 | 15 | 15 | 15.5 | 14.5 | 15.5 | 15.5 |
| Point 3 | 61.9 | 61.5 | 57.6 | 58.5 | 59.5 | 58.5 | 60.5 |
| Point 4 | 81.8 | 80.3 | 80.3 | 78.9 | 80.3 | 78.9 | 78.9 |
| Point 5 | 102 | 102 | 102 | 102 | 102 | 102 | 102 |

0,0@+1.265,15.8@+2.7,61.9@+2.9,81.8@+2.975,102
0,0@+2.5,15@+5.275,61.5@+5.725,80.3@+5.9,102
0,0@+3.725,15@+7.8,57.6@+8.65,80.3@+8.9,102
0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102
0,0@+6.25,14.5@+13.2,59.5@+14.425,80.3@+14.85,102
0,0@+7.025,15.5@+14.7,58.5@+16.25,78.9@+16.8,102
0,0@+8.375,15.5@+17.65,60.5@+19.125,78.9@+19.7,102

**Figure L-83: Lost Opportunity Supply Curve Values**

As described in section "Supply Curves," page L-44, lost opportunity conservation depends on the rate at which construction is taking place, which is related to overall load growth. The supply curve logic for lost opportunity conservation accommodates this behavior. In the sample workbook, the cell {AQ377} contains the following formula

=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)

The last parameter in the UDF refers to cell {AP240}. Row 240 contains the ratio of on-peak load in column {AP} to an on-peak load benchmark level:

=AP183/AP195

If the period's on-peak load exceeds the period's benchmark on-peak load by 1%, the applicable supply curves quantity will increase 1% at each price level.

The section "Supply Curves" describes the remaining parameters in these formulas. The section “Decision Criteria,” page L-90, explains the price criterion (AP$233+$R$375) in this formula.

## Discretionary Conservation

Discretionary conservation, also referred to as dispatchable or schedulable conservation, is energy efficiency that the region can pursue at any time. Some of these opportunities will disappear over time, so the supply curve represents a forecast of the balance of measures available in 2025. Figure L-84 illustrates a supply curve that the regional models uses for representing discretionary conservation. The values are in Figure L-85 [17]. This source of conservation also has a T&D credit of 5.5 mills per kilowatt-hour.

Discretionary conservation does not increase over time for a couple of reasons. First, the Council does not attempt to forecast technology improvements. The technology and standards are static. Second, the Council assumes that any structure built today with all cost-effective efficiencies will have no potential for additional improvement in 10 years. If conservation for the new facility becomes a lost opportunity, it remains a lost opportunity. It cannot become discretionary after some time has passed.

Several aspects of discretionary conservation economics became evident early in studies with the regional model. First, because there is so much discretionary conservation that is cost-effective at today's market prices that, without constraining the rate of development, the model would select unrealistic rates of conservation acquisition. In practice, program infrastructure, rate impacts, and budgets constrain development. To reflect this, the supply curve logic was modified to incorporate a rate limit. The Council considered several levels of ramp rate, and settled on a rate (30 MW) that appeared to significantly improve cost and risk but be realistic in light of some of the known

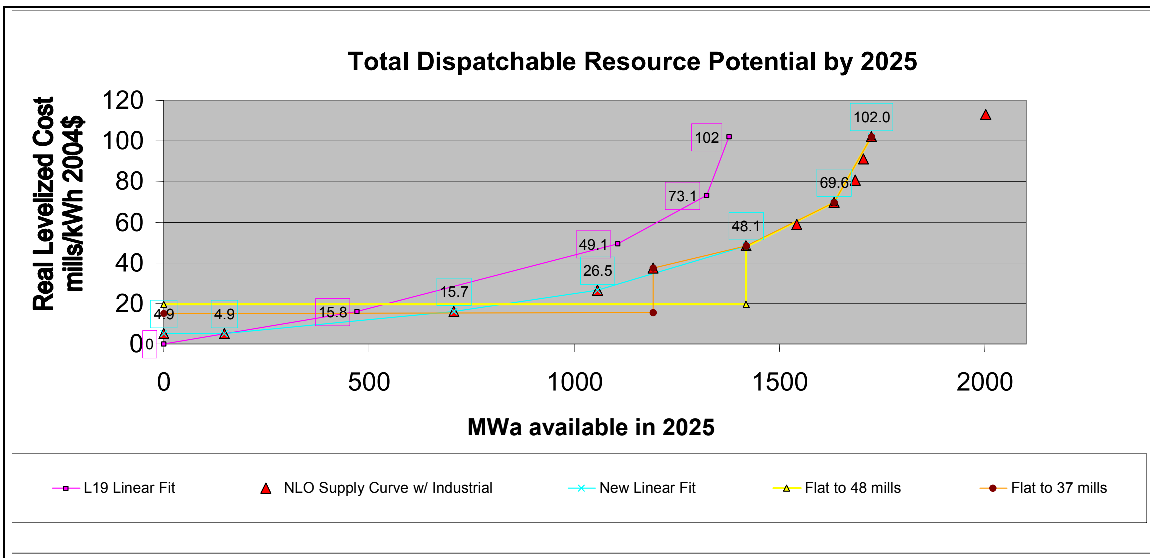



Figure L-84: Discretionary Conservation Supply Curve constraints. The selection of this discretionary conservation ramp rate is the subject of a sensitivity analysis in Appendix P.

The second aspect of discretionary conservation economics that became evident was that bundling of conservation programs prohibited strict implementation of the supply curve. When a utility decides to pursue discretionary conservation, they commit resources and crews to a commercial or industrial location. While at these locations, it makes economic sense to implement a host of programs, not just the ones below a given point on the supply curve. It is not realistic to expect that utilities will be able to "cherry pick" only those measures that are cost-effective and do so with 100 percent effectiveness.

Flat to 48 mills

**Energy (Q)**

| | Year 2025 Total Available |
|---|---|
| Point 1 | 0 |
| Point 6 | 1418 |
| Point 6 | 1419 |
| Point 8 | 1633 |
| Point 11 | 1723 |

**Price (P)**

| | |
|---|---|
| Point 1 | 19.5 |
| Point 6 | 19.6 |
| Point 6 | 48.0 |
| Point 8 | 69.6 |
| Point 11 | 102.0 |

0,19.5@+
1418,19.6@+
1419,48@+
1633,69.6@+
1723,102

0,19.5@+1418,19.6@+1419,48@+1633,69.6@+1723,102

**Figure L-85: Data for Discretionary Conservation Supply Curve**

To model the situation, the model uses a modified discretionary conservation supply curve. Council staff decided to change the shape of the supply curve to increase the average cost of discretionary conservation available at the low end of the supply curve. Where to make these modifications is to an extent arbitrary. Council staff considered several factors including the regional portfolio model's apparent appetite for discretionary conservation costing less than 40 mills per kilowatt-hour, the historic performance of utility programs, and the mix of discretionary conservation measures available. The staff chose to represent discretionary conservation with a first block representing all the conservation under the curve up to 48 mils per kilowatt-hour. This is about 1490 average megawatts and average cost of 19.6 mils per kilowatt-hour in 2004 constant dollars. It includes 200 average megawatts of conservation above 40 mils per kilowatt-hour. [17]

The supply curve logic for discretionary conservation in cell {AQ377} contains the following formula

=sfSupplyCurve(AP235+$R$384,$P386,AP46,AP386)*1152*1.402

The section "Supply Curves" describes the parameters in this formulas. The section "Decision Criteria," page L-91, explains the price criterion (AP235+$R$384) in this formula.

## Price Responsive Hydro

The model uses a reversible supply curve to represent price responsive hydro. Section "Supply Curves," page L-48, describes the considerations that went into selecting values to represent this resource.

## Contracts

Contract data represents firm energy imports and exports to the region. The source of this data is the BPA 2004 White Book [18]. Energy values appear in Figure L-86 as extracted from the source. Note that this figure uses calendar years, not hydro years.

Using a calendar of NERC holidays, the energy values in Figure L-86 become power levels over each hydro quarter. This permits restatement in standard periods. Figure L-87 illustrates the resulting values, which the model then incorporates. Because the values provided by BPA extend only through 2014 and because of the regular pattern exhibited in the last several years, the model extends the pattern of energy values through the end of the study.

As explained in section "Contracts," page L-32, the model can counter-schedule these firm contracts for economic reasons. Consequently, the contracts have little effect on market prices. Counter-scheduling affects the amount of power available to the market, which stabilizes prices. The contracts, however, do affect portfolio economics and risk. Regional load still benefits from the protection that these contracts afford against economic exposure to the market.

This concludes the appendix description of resources that the regional model uses. The model represents existing regional resources in aggregate plants, but SBC wind and IPP modeling requires special attention. Contract data reflects the most recent BPA White Book, extended through the end of the study. Most new resources use the UDF described in the section "New Resources, Capital Costs, and Planning Flexibility" for capital costs; all new resources except wind use the UDF described in "Thermal Generation" for variable costs. Wind must account for integration cost and special renewables credits. New conservation energy has its own, special supply curve logic.

One aspect of the resources that this section did not discuss is how the model constructs plans. Plans must conform to certain constraints: A plant, once constructed, may not disappear the next year, for example, and there are constraints on the addition of wind generation. The next section describes how the Crystal Ball and OptQuest Excel add-ins use the regional model to prepare the feasibility space, including constructing plans subject to constraints and finding least-cost plans subject to risk constraints. It also describes some utilities that help the analyst make sense of the simulation results.

| MWhs | | | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| On/Off Peak | Cal Yea | I/E | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| On-Peak | 2004 | Export | | | | | | | | 1009725 | 982675 | 877696 | 824291 | 874006 |
| | | Import | | | | | | | | 163798 | 127562 | 170293 | 313234 | 424215 |
| | 2005 | Export | 801258 | 733297 | 790424 | 773177 | 784213 | 876105 | 909973 | 910011 | 873102 | 742359 | 705020 | 736716 |
| | | Import | 392401 | 318405 | 287876 | 234573 | 130284 | 172270 | 190170 | 187681 | 155162 | 179321 | 329674 | 412567 |
| | 2006 | Export | 727018 | 665963 | 737764 | 712355 | 739955 | 795224 | 811648 | 804054 | 772577 | 617872 | 585371 | 606787 |
| | | Import | 382401 | 307691 | 269559 | 219490 | 102443 | 171521 | 181210 | 149319 | 132522 | 153725 | 301904 | 373910 |
| | 2007 | Export | 611999 | 552671 | 611035 | 592672 | 615517 | 672647 | 710778 | 728831 | 693228 | 609790 | 572397 | 594008 |
| | | Import | 345772 | 262714 | 226411 | 178287 | 87527 | 143906 | 134992 | 140868 | 92166 | 139149 | 279464 | 363590 |
| | 2008 | Export | 554273 | 517882 | 548613 | 540204 | 548669 | 577665 | 591676 | 566925 | 552765 | 544691 | 505046 | 534237 |
| | | Import | 265610 | 259835 | 231893 | 194563 | 106788 | 149176 | 156358 | 68746 | 56616 | 80397 | 157859 | 208871 |
| | 2009 | Export | 533241 | 481879 | 527510 | 522319 | 530517 | 566911 | 576003 | 615994 | 600009 | 593652 | 556458 | 587668 |
| | | Import | 207370 | 179846 | 171864 | 133744 | 49577 | 84542 | 82144 | 68746 | 56616 | 80397 | 157859 | 208871 |
| | 2010 | Export | 582702 | 530029 | 584596 | 573560 | 583288 | 613019 | 623807 | 604813 | 589060 | 578493 | 551365 | 578666 |
| | | Import | 201310 | 179846 | 176774 | 133744 | 49577 | 65323 | 63549 | 50151 | 56616 | 77930 | 123928 | 168103 |
| | 2011 | Export | 573659 | 521787 | 575314 | 564448 | 572062 | 607287 | 613611 | 602545 | 582472 | 571772 | 545234 | 572658 |
| | | Import | 162110 | 142214 | 134438 | 92976 | 49577 | 65323 | 61792 | 51574 | 56616 | 77930 | 123928 | 168103 |
| | 2012 | Export | 567608 | 533510 | 569018 | 553813 | 567586 | 594468 | 600522 | 588566 | 564402 | 559651 | 530453 | 554066 |
| | | Import | 162110 | 147835 | 134438 | 90327 | 50794 | 65323 | 61792 | 51574 | 54726 | 80397 | 117520 | 156565 |
| | 2013 | Export | 556503 | 502423 | 549805 | 543019 | 551864 | 574990 | 589465 | 573374 | 550241 | 553050 | 524466 | 548234 |
| | | Import | 159981 | 136234 | 131096 | 92976 | 50794 | 63816 | 63549 | 51574 | 54726 | 80397 | 117520 | 156565 |
| | 2014 | Export | 550624 | 497030 | 543662 | 536926 | 545266 | 547101 | 560816 | | | | | |
| | | Import | 159981 | 136234 | 131096 | 92976 | 50794 | 63816 | 63549 | | | | | |
| Off-Peak | 2004 | Export | | | | | | | | 294739 | 277615 | 204704 | 200887 | 212999 |
| | | Import | | | | | | | | 151512 | 129214 | 157907 | 254667 | 322426 |
| | 2005 | Export | 206106 | 173346 | 185717 | 187526 | 187707 | 220818 | 278787 | 228051 | 227494 | 177214 | 175611 | 184580 |
| | | Import | 315020 | 223304 | 199821 | 172771 | 114193 | 127641 | 180810 | 158877 | 151294 | 165046 | 267819 | 313242 |
| | 2006 | Export | 192800 | 162197 | 173580 | 184952 | 166932 | 190604 | 233049 | 225936 | 225078 | 113840 | 114234 | 127931 |
| | | Import | 306420 | 215268 | 186592 | 175200 | 84375 | 127094 | 173105 | 131171 | 133182 | 144848 | 245665 | 306460 |
| | 2007 | Export | 121181 | 106807 | 113301 | 123682 | 103719 | 131737 | 176143 | 174600 | 181766 | 100408 | 106934 | 120228 |
| | | Import | 254097 | 181529 | 155384 | 142399 | 72655 | 106883 | 133502 | 125022 | 107164 | 125005 | 227713 | 297585 |
| | 2008 | Export | 81735 | 71666 | 78202 | 78940 | 63894 | 81183 | 85311 | 83285 | 79150 | 69034 | 77862 | 80842 |
| | | Import | 195503 | 176759 | 171776 | 138310 | 74153 | 103328 | 125513 | 60159 | 56590 | 68730 | 130767 | 142349 |
| | 2009 | Export | 80178 | 69203 | 76357 | 77201 | 64188 | 74782 | 83524 | 81268 | 77238 | 67130 | 78969 | 82189 |
| | | Import | 133657 | 104994 | 108520 | 86326 | 31222 | 47578 | 66998 | 60159 | 56590 | 68730 | 130767 | 142349 |
| | 2010 | Export | 85423 | 70346 | 73597 | 78239 | 65095 | 75714 | 84594 | 82248 | 78101 | 72013 | 76203 | 83601 |
| | | Import | 139718 | 104994 | 103609 | 86326 | 31222 | 28637 | 47277 | 40438 | 51694 | 61810 | 96586 | 112734 |
| | 2011 | Export | 86806 | 71546 | 74821 | 79328 | 66045 | 76693 | 90101 | 78848 | 78988 | 72996 | 77395 | 85051 |
| | | Import | 108535 | 79055 | 75563 | 61165 | 26162 | 28637 | 49034 | 39016 | 51694 | 61810 | 96586 | 112734 |
| | 2012 | Export | 88228 | 73662 | 76080 | 84855 | 64784 | 77699 | 91245 | 79895 | 84318 | 63831 | 72235 | 83606 |
| | | Import | 108535 | 81337 | 75563 | 63815 | 24945 | 28637 | 49034 | 39016 | 53583 | 59343 | 96586 | 117651 |
| | 2013 | Export | 79220 | 68301 | 74755 | 75553 | 59241 | 76751 | 81468 | 74743 | 78558 | 64894 | 73523 | 85174 |
| | | Import | 104042 | 79055 | 78905 | 61165 | 24945 | 30144 | 47277 | 39016 | 53583 | 59343 | 96586 | 117651 |
| | 2014 | Export | 80757 | 69633 | 76115 | 76764 | 60299 | 77839 | 82705 | | | | | |
| | | Import | 104042 | 79055 | 78905 | 61165 | 24945 | 30144 | 47277 | | | | | |

**Figure L-86: Regional Contract Energy (MWh)**

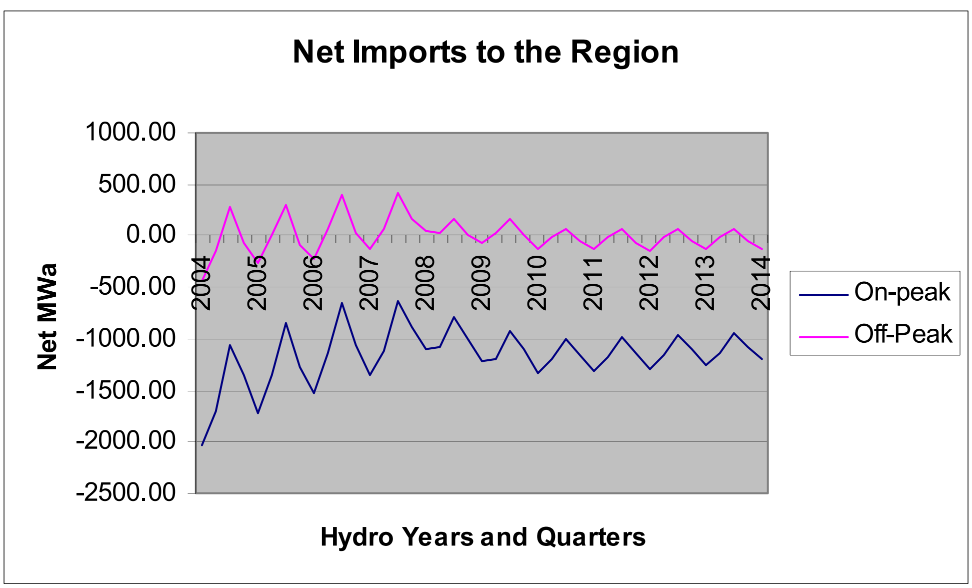



**Figure L-87: Net Contract Imports MW**

# *Using the Regional Model*

This section describes how a user can run the regional model alone, or can use Excel add-ins to perform Monte Carlo simulation and plan optimization. The last portion of this section describes utilities the Council used to verify modeling and extract additional insights from the simulations.

## Stand-Alone Calculation

When the workbook opens, the Excel calculation mode is set to Manual and special macros recalculate the worksheet in the order described in section "Logic Structure," at page L-9, and in section "RRP algorithm," page L-51. Because the workbook does not recalculate automatically, making changes to data in the workbook appears to have no effect.

To recalculate the worksheet, the user must execute the workbooks "Auto_Open" macro. By default, this macro is assigned the hotkey combination <CTRL>-I.

When the user presses <CTRL>-I, she can watch the calculations proceed from left to right across the worksheet. Recalculation requires about a second and a half. During recalculation, most of the values in the worksheet, and in particular the total system cost, are invalid. Their values may appear nonsensical. For example, prices may be negative.

## Crystal Ball Simulations

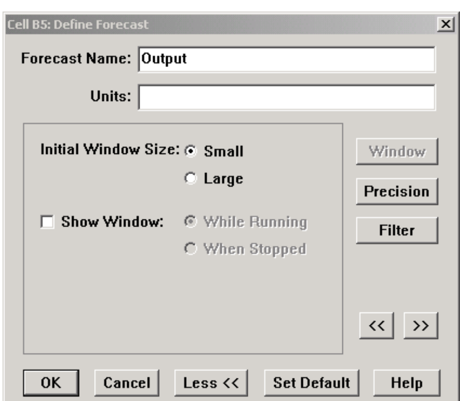



**Figure L-88: Defining Forecasts**

To perform Monte Carlo simulation or to prepare for creating a feasibility space, the user must specify Monte Carlo run preferences. The user should configure forecast cells to suppress forecast windows during the run, as in Figure L-88. Clicking on the Run Preferences button, illustrated in Figure L-89, the user has a sequence of choices to make.

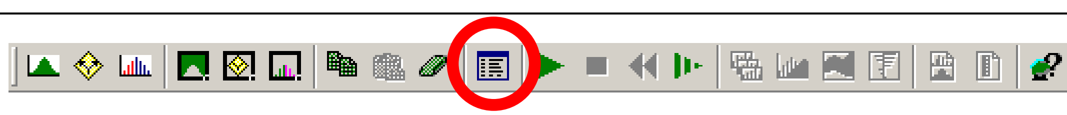


Figure L-89: Run Preferences

The first of these choices, illustrated in Figure L-90, determines the number of games or futures and how the application should handle calculation in each of those. Regional model studies used 750 games. This assured that there are 75 samples of the 10% worse outcomes. This number of samples yields a standard error that is about 12% of the tail's standard deviation. The 750 games provide a standard error of the mean that is about 4% of the distribution's standard deviation, or about $250 million net present value. Because of the size of the standard error of the mean, the Council always studied those plans that were nearly efficient. The Council examined all plans that were within $250 million cost and risk of the efficient frontier for evidence that a different resource strategy might be efficient.

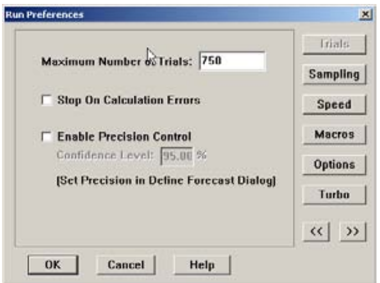



**Figure L-90: Run Prefs, Trials**

The second run preference is Sampling (Figure L-91). All studies used the same sequence of random numbers and the same initial seed value. Specifying the random number seed value is essential to reproducing and verifying simulations. Latin Hypercube is a statistical method that forces the sampling of less likely portions of a statistical distribution. All regional model simulations used the Latin Hypercube option.

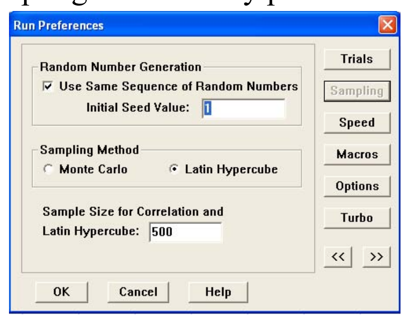



**Figure L-91: Run Prefs, Sampling**

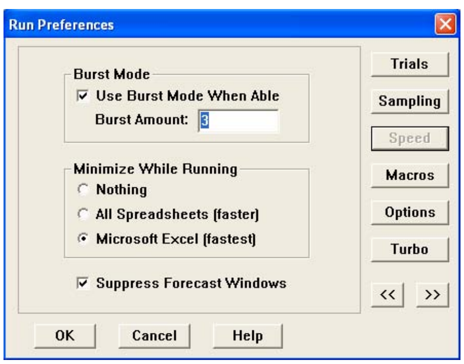



**Figure L-92: Run Prefs, Speed**

The third run preference, Speed, features an option called Burst Mode (Figure L-92). Burst Mode does different things depending on whether the user is running under Normal or Turbo simulation mode. Under Normal mode, this option suppresses screen updating for the number of games that the user specifies. Under Turbo mode, this controls the number of games each Worker receives in a packet. For the regional model, small packets containing only three futures appear to optimize performance.

The fourth run preference permits the user to specify macros that Crystal Ball will run during its simulation. The regional model employs two such macros, illustrated in Figure L-93. The macro names must be here whenever the user runs a Monte Carlo simulation or executes the regional model under Crystal Ball's single-step feature.[35] The regional model has a special macro that loads the names of the two subroutines into the correct fields in this dialog box. The user invokes this macro by pressing <CTRL>-M. Using the macro not only saves time but also reduces the likelihood of inadvertent errors. The

[35] Warning: The single-step feature does not reproduce the same games as when Monte Carlo simulation employs a user-specified seed value, even if the user specifies a seed value. The next section describes a utility to extract the values for assumption cells corresponding to a particular future.

subroutine names specified in this run preference dialog box must include the name of the regional portfolio model workbook. This name to typically changes from run to run.

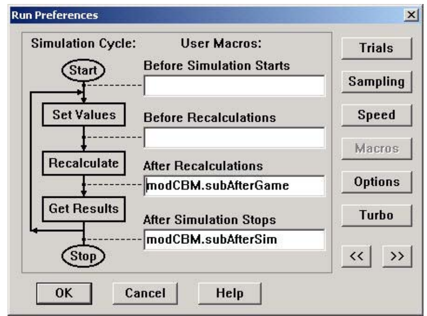



**Figure L-93: Run Prefs, Macros**

Executing the <CTRL>-M macro serves another purpose. For the macros in the regional model to perform correctly, there must not be any other Excel workbook present. Depending on the computer environment, Excel may load personal or hidden workbooks that are not evident to the user. This macro will locate any such workbooks and warn the user to close them.[36]

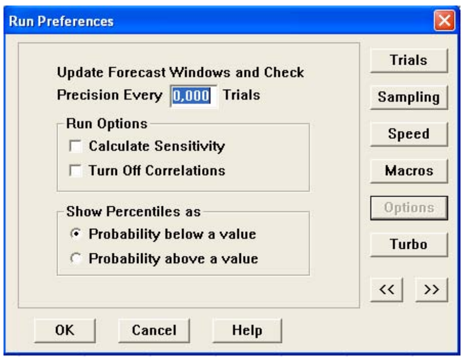



**Figure L-94: Run Prefs, Options**

Figure L-94 illustrates a fifth option, which should be set up as shown and thereafter disregarded. For reasons described in the next section, the regional model does not use precision or confidence testing.

The final option controls whether the Monte Carlo simulation will run in Normal (Figure L-96) or Turbo mode (Figure L-95). The user can run the regional model in either mode. For the Council's work, Turbo mode produced a tenfold decrease in run time for the creation of feasibility spaces. An important verification test, described below, is comparing the results of a plan run under Normal mode on a single machine and under Turbo model on multiple machines. The results for each game must be identical.

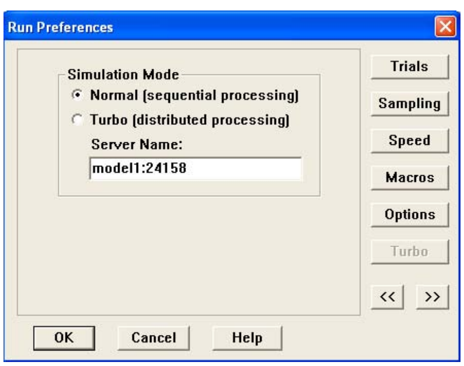



**Figure L-96: Run Prefs, Turbo (Normal)**

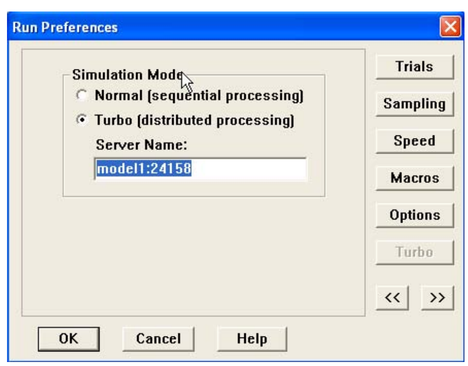



**Figure L-95: Run Prefs, Turbo (Turbo)**

[36] Closing the workbook may require entering the Visual Basic editing environment and issuing the Workbooks("***name***.xls").close command in the Immediate Window, where ***name*** is the offending workbook.

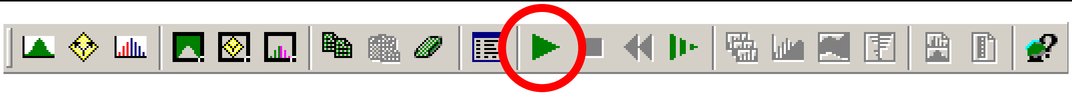


**Figure L-97: Begin Simulation**

With these preparations, the user is prepared to begin the Monte Carlo simulation using the start button in Figure L-97 or to prepare a stochastic optimization run as illustrated in Figure L-98. The next section describes considerations when preparing the optimization.

## OptQuest Stochastic Optimization

When a user endeavors to create feasibility space using OptQuest, he can either open an existing configuration file or create one from scratch. If he chooses to create one from scratch, OptQuest will read the workbook and find all assumption, decision, and forecast cells. The user would then proceed through the following steps.

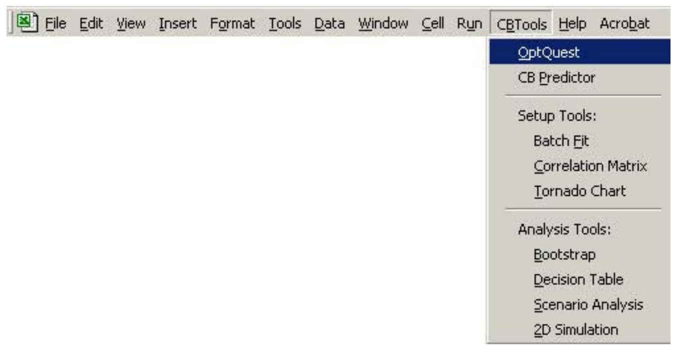
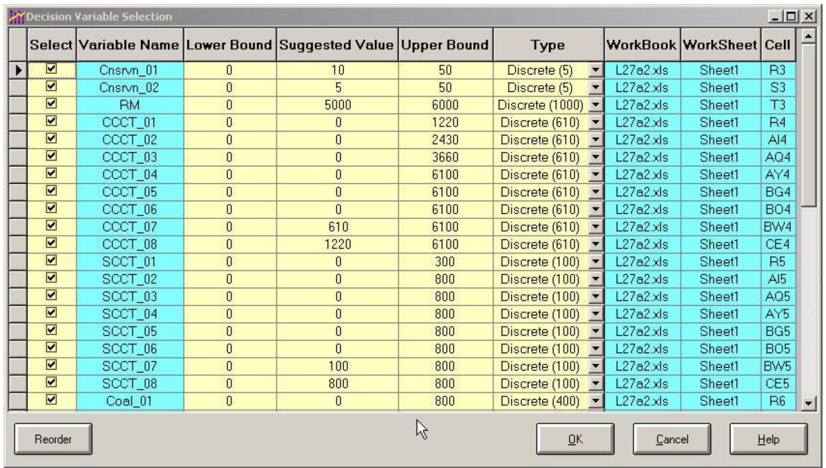



**Figure L-98: Menu Bar**

The OptQuest menu bar has four buttons that, proceeding from left to right in Figure L-99, open "Variable Selection," "Constraints," "Forecast Selection," and "Run Options" dialog boxes, respectively.

**Figure L-99: OptQuest Menu Bar**

Variable Selection, Figure L-100, is where the user specifies the value for decision cells. The optimizer will endeavor to perform its task by modifying the values of these cells. The column labeled "Type" specifies how the optimizer can vary the associated cell value. In this example, the optimizer can choose capacities for CCCT_01 in the fourth row between zero and 1220 MW in discrete steps of 610 MW. CCCT_01 is the decision cell that determines how much cumulative construction might be started by September of calendar year 2003. (See section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65.). CCCT_02 is the corresponding number of megawatts for December, 2007, and so forth. The user must determine step size, upper limit, and lower limit through trial and error. If an upper or lower limit is constraining the plans along the efficient frontier, this would be an indication that the values for the constraints should be adjusted. The user endeavors to keep the number of choices as small as possible, however, because the size of the search space grows explosively with the number of steps and decision cells available. [**19**]




| Select | Variable Name | Lower Bound | Suggested Value | Upper Bound | Type | WorkBook | WorkSheet | Cell |
|---|---|---|---|---|---|---|---|---|
| ☑ | Cnsrvn_01 | 0 | 10 | 50 | Discrete (5) | L27a2.xls | Sheet1 | R3 |
| ☑ | Cnsrvn_02 | 0 | 5 | 50 | Discrete (5) | L27a2.xls | Sheet1 | S3 |
| ☑ | RM | 0 | 5000 | 6000 | Discrete (1000) | L27a2.xls | Sheet1 | T3 |
| ☑ | CCCT_01 | 0 | 0 | 1220 | Discrete (610) | L27a2.xls | Sheet1 | R4 |
| ☑ | CCCT_02 | 0 | 0 | 2430 | Discrete (610) | L27a2.xls | Sheet1 | AI4 |
| ☑ | CCCT_03 | 0 | 0 | 3660 | Discrete (610) | L27a2.xls | Sheet1 | AQ4 |
| ☑ | CCCT_04 | 0 | 0 | 6100 | Discrete (610) | L27a2.xls | Sheet1 | AY4 |
| ☑ | CCCT_05 | 0 | 0 | 6100 | Discrete (610) | L27a2.xls | Sheet1 | BG4 |
| ☑ | CCCT_06 | 0 | 0 | 6100 | Discrete (610) | L27a2.xls | Sheet1 | BO4 |
| ☑ | CCCT_07 | 0 | 610 | 6100 | Discrete (610) | L27a2.xls | Sheet1 | BW4 |
| ☑ | CCCT_08 | 0 | 1220 | 6100 | Discrete (610) | L27a2.xls | Sheet1 | CE4 |
| ☑ | SCCT_01 | 0 | 0 | 300 | Discrete (100) | L27a2.xls | Sheet1 | R5 |
| ☑ | SCCT_02 | 0 | 0 | 800 | Discrete (100) | L27a2.xls | Sheet1 | AI5 |
| ☑ | SCCT_03 | 0 | 0 | 800 | Discrete (100) | L27a2.xls | Sheet1 | AQ5 |
| ☑ | SCCT_04 | 0 | 0 | 800 | Discrete (100) | L27a2.xls | Sheet1 | AY5 |
| ☑ | SCCT_05 | 0 | 0 | 800 | Discrete (100) | L27a2.xls | Sheet1 | BG5 |
| ☑ | SCCT_06 | 0 | 0 | 800 | Discrete (100) | L27a2.xls | Sheet1 | BO5 |
| ☑ | SCCT_07 | 0 | 100 | 800 | Discrete (100) | L27a2.xls | Sheet1 | BW5 |
| ☑ | SCCT_08 | 0 | 800 | 800 | Discrete (100) | L27a2.xls | Sheet1 | CE5 |
| ☑ | Coal_01 | 0 | 0 | 800 | Discrete (400) | L27a2.xls | Sheet1 | R6 |

**Figure L-100: Variable Selection**

The values for decision cells illustrated in Figure L-100 are completely independent. The optimizer uses the equations in the Constraints dialog box, Figure L-101, to enforce any relationship among those values. The first seven equations in Figure L-101, for example, constrain the amount of CCCT capacity to be non-decreasing. The last seven equations in Figure L-101 specify that the model construct no more than 2000 MW of wind between decision cells. Two years separate each technology's decision cells after 2007 in the regional model.

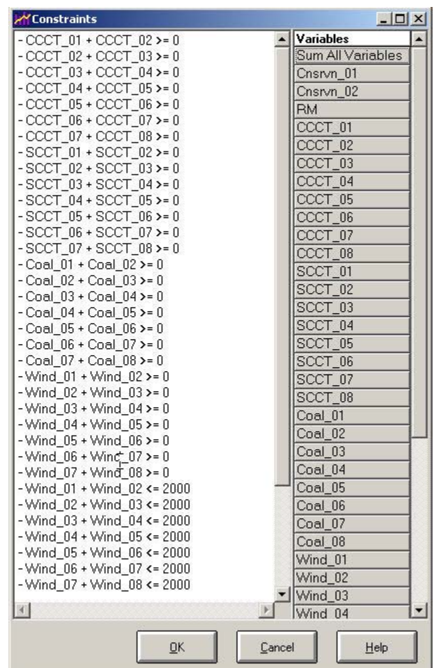
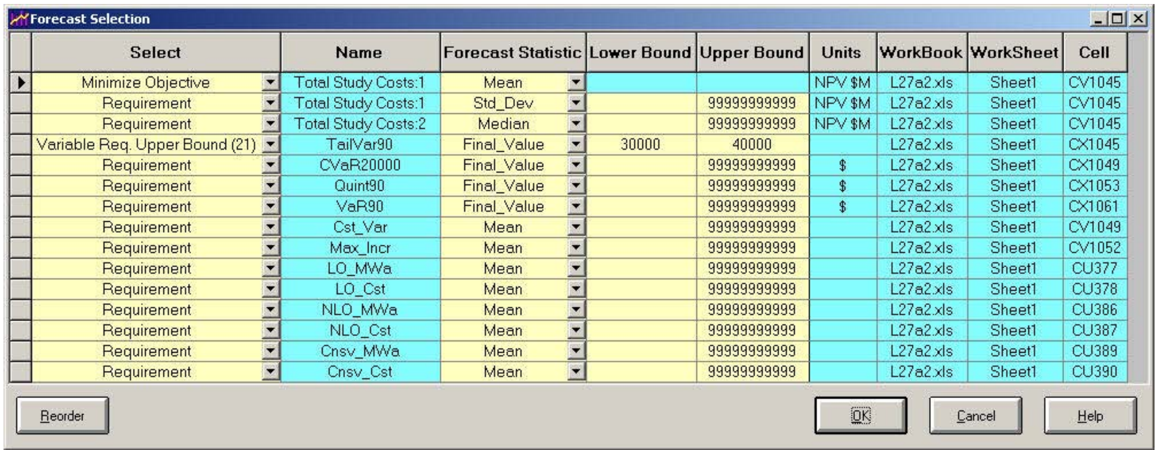



**Figure L-101: Constrains**

The "Forecast Selection" dialog window, illustrated in Figure L-102, is where the user specifies the objective function and risk constraint. The first row in this example specifies that our objective is to minimize total study cost. The fourth row specifies that a plan will be deemed feasible if it satisfies the upper bound on $\text{TailVaR}_{90}$. The optimization does not use the other rows. By specifying that other variables are requirements and placing an upper bound on these requirements guaranteed to be non-binding, the user fools the optimizer into keeping track of their values and reporting their values in the final optimization log.

Specifying that the $\text{TailVaR}_{90}$ risk measure is a variable-requirement upper bound permits the user to create the efficient frontier. Initially, this upper bound will start out at its lowest value, \$30 B in this example. (Bounds for $\text{TailVaR}_{90}$ in Figure L-102 are in millions of 2004 NPV dollars.) The optimizer will first attempt to find a plan that satisfies this upper bound. By choosing a sufficiently low upper bound, the user guarantees that the optimizer will seek the least-risk plan. After giving the optimizer sufficient opportunity to identify the least-risk plan, the user lifts the upper bound. In our example, the upper bound will have 21 even steps between \$30 B and \$40 B inclusive. (See the value in parenthesis under the first column.) After the upper bound has been



| Select | Name | Forecast Statistic | Lower Bound | Upper Bound | Units | WorkBook | WorkSheet | Cell |
|---|---|---|---|---|---|---|---|---|
| Minimize Objective | Total Study Costs:1 | Mean | | | NPV $M | L27a2.xls | Sheet1 | CV1045 |
| Requirement | Total Study Costs:1 | Std_Dev | | 99999999999 | NPV $M | L27a2.xls | Sheet1 | CV1045 |
| Requirement | Total Study Costs:2 | Median | | 99999999999 | NPV $M | L27a2.xls | Sheet1 | CV1045 |
| Variable Req. Upper Bound (21) | TailVar90 | Final_Value | 30000 | 40000 | | L27a2.xls | Sheet1 | CX1045 |
| Requirement | CVaR20000 | Final_Value | | 99999999999 | $ | L27a2.xls | Sheet1 | CX1049 |
| Requirement | Quint90 | Final_Value | | 99999999999 | $ | L27a2.xls | Sheet1 | CX1053 |
| Requirement | VaR90 | Final_Value | | 99999999999 | $ | L27a2.xls | Sheet1 | CX1061 |
| Requirement | Cst_Var | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CV1049 |
| Requirement | Max_Incr | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CV1052 |
| Requirement | LO_MWa | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU377 |
| Requirement | LO_Cst | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU378 |
| Requirement | NLO_MWa | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU386 |
| Requirement | NLO_Cst | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU387 |
| Requirement | Cnsv_MWa | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU389 |
| Requirement | Cnsv_Cst | Mean | | 99999999999 | | L27a2.xls | Sheet1 | CU390 |



**Figure L-102: Forecast Selection and Requirements Specification**

lifted a sufficient number of times, the optimizer will find at least one plan that satisfies the upper bound. At this point, the optimizer will endeavor to minimize the cost objective function. The optimizer will attempt to find the least cost plan subject to this risk constraint. After giving the optimizer sufficient opportunity to identify the least cost plan, the user then again lifts the upper bound on $\mathrm{TailVaR}_{90}$. The optimizer will then endeavor to minimize cost subject to the new upper bound on $\mathrm{TailVaR}_{90}$. The process continues until the optimizer has swept out the entire efficient frontier.

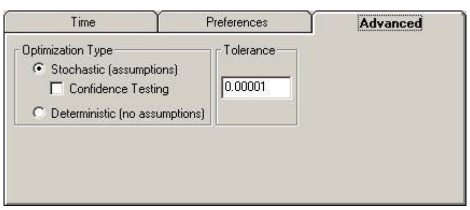



**Figure L-103: Run Options (1/3)**

Finally, the user specifies options for the run by clicking on the clock icon on the OptQuest menu bar (Figure L-99) to open the Options tab sheet. The first tab, labeled Advanced in Figure L-103, permits the user to specify whether optimization should be deterministic or stochastic. To create the feasibility space, the user selects Stochastic. It is imperative that the user leave the Confidence Testing option box unchecked. An undocumented problem running Crystal Ball Turbo under OptQuest produces random, meaningless results. The second to Options tab, Preferences, permits users to specify a descriptive string for output reports and the location of the optimization log file. An example of the log file appears below. The third Options tab, Time, permits the user to specify the amount of time for the optimization run. Using the Turbo mode, a feasibility space requires between 24 and 30 hours. Permitting two days for the optimization run should be ample therefore.

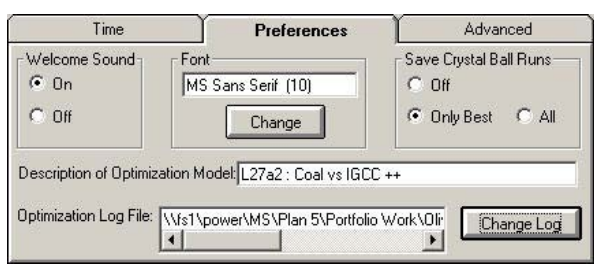



**Figure L-104: Run Options (2/3)**

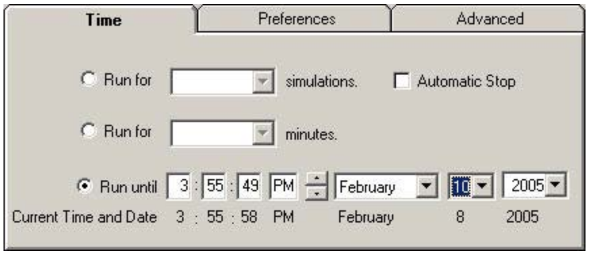



**Figure L-105: Run Options (3/3)**

The optimization is ready to run. The user may click on the run button in Figure L-106 to launch the optimization.

**Figure L-106: LAUNCH!**

## Portfolio Model Reports And Utilities

In section "New Resources, Capital Costs, and Planning Flexibility," page L-74, the appendix describes a utility for extracting the planning status and cost for each cohort of a new resource. The Council has developed many other applications for extracting and evaluating regional model data. This section describes some of these utilities, including those that help the user perform the important tasks of verifying the computer simulations and "drilling down" through simulation results to the calculations performed by each cell for each plan, under each future.

This section describes utilities which

- create feasibility spaces and efficient frontiers
- extract data for each future and animate the "spinner" graphs, illustrating the behavior and performance of a plan under each future
- extract the assumption values for a particular future and populate a copy of the portfolio model with them for detailed examination
- run arbitrary sets of plans automatically and collect data
- paint prescribed cells with assumptions or forecasts
- compare two feasibility spaces to determine which, if any, plans are identical
- permit the user to compute the "stochastic adjustment" that results in distributions with a target mean, by period
- install menu bars to perform standard portfolio model or Olivia tasks, such as those listed above

Many of these utilities are included as special macros in the regional model. Some of them are macros in stand-alone workbooks. All of them are available to users from the Council upon request. They appear in this appendix because they demonstrate the ease with which and Excel-based model facilitates analysis. They also provide some insight into how the Council performed some of the tasks described elsewhere in this appendix.

## Creating Feasibility Spaces and Efficient Frontiers

The previous section describes the means to constructing a feasibility space. A routine analysis is the comparison of two feasibility spaces. For example, one feasibility space may reflect a slightly modified set of assumptions, such as alternative probabilities for a $CO_2$ tax; the other may employ basecase assumptions. The comparison takes the form of an Excel graph such as the example in Figure L-107. The steps that the user would go through manually to create such a graph are:

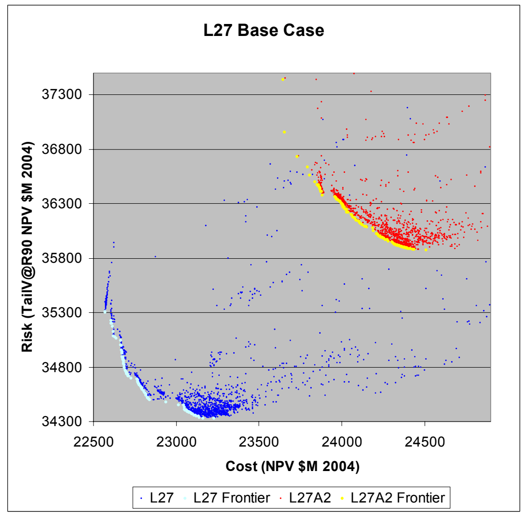



**Figure L-107: Comparison of Feasibility Spaces**

- Convert the OptQuest output (see Figure L-108) to an Excel worksheet for analysis
- Sort the plans to reveal those that are 1) on the efficient frontier, 2) near the efficient frontier, and 3) do not belong to either of these categories (see Figure L-109)
- Re-label columns for easier comprehension. For example, the column of representing values for CCCT_02 might be relabeled to CCCT_1207 to reflect the fact that this decision cell controls construction beginning December 2007.
- Add the data points from the worksheet to a graph that already has the data points for the basecase. This includes identifying which points are on the efficient frontier and formatting those points with a distinct shape and color so that they are clearly distinguished.

The workbook "Analysis of Optimization Run.xls"[37] contains the macro sub_PROCESS, which performs these tasks automatically. To use the macro, the user merely identifies the file containing the OptQuest output and a string for labeling the analysis or sensitivity case.

It may be helpful to understand the typical structure of the worksheet containing sorted plans, illustrated in Figure L-109. An example of this report appears in worksheet "Base Case" of the workbook "Analysis of Optimization Run.xls." Figure L-109 is an abbreviated version, with certain columns and rows removed for clarity.

- Column A identifies the plan number, which is assigned sequentially as the simulations are performed
- Columns B through AR specify the value of decision cells. As described in previous sections, these specify the plan.

[37] This workbook is available from the Council's website or from the Council upon request.

- Columns AS through BG specify the values for forecast cells. These are the results of the simulation. Particularly significant are the mean net present value study cost in column AS and the $TailVaR_{90}$ risk in column AV.
- Column BH specifies plans on the efficient frontier. This report sorts the plans so that all of the plans on the efficient frontier appear together at the top of the report.
- Column BI specifies plans that are near the efficient frontier. These are plans within $250 million cost and risk of the efficient frontier.

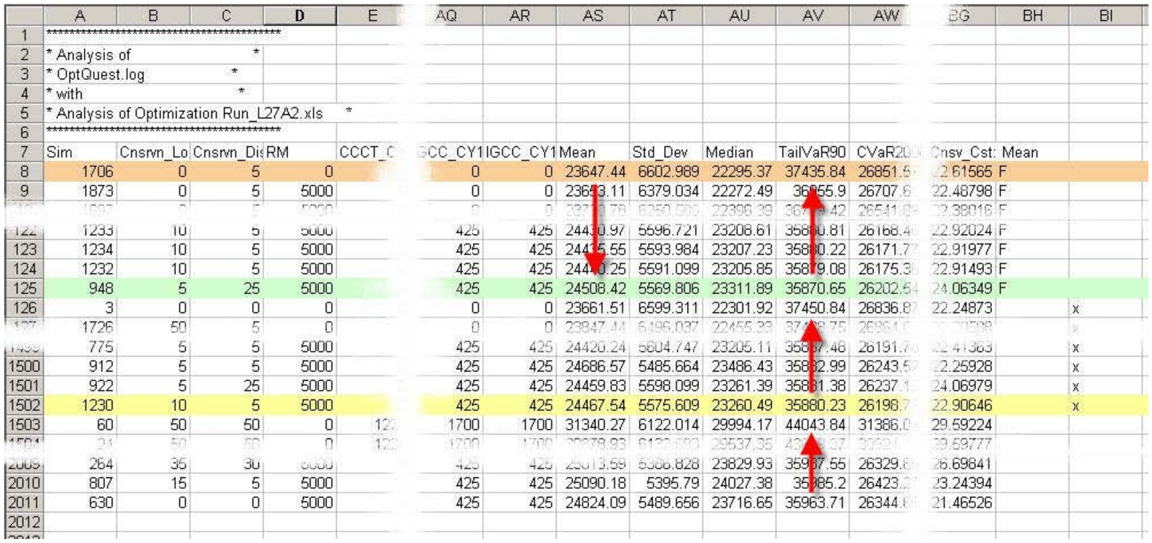
```
Simulation: 1

Values of Variables:
Cnsrvn_01: 20
Cnsrvn_02: 10
RM: 5000
CCCT_01: 0
CCCT_02: 0
CCCT_03: 0
CCCT_04: 0
CCCT_05: 0
CCCT_06: 0
CCCT_07: 610
CCCT_08: 1220
SCCT_01: 0
SCCT_02: 0
SCCT_03: 0
SCCT_04: 0
SCCT_05: 0
SCCT_06: 0
SCCT_07: 200
SCCT_08: 200
Coal_01: 0
Coal_02: 0
Coal_03: 0
Coal_04: 0
Coal_05: 0
Coal_06: 0
Coal_07: 0
Coal_08: 0
Wind_01: 0
Wind_02: 0
Wind_03: 100
Wind_04: 600
Wind_05: 2500
Wind_06: 4500
Wind_07: 5000
Wind_08: 5000
IGCC_01: 0
IGCC_02: 0
IGCC_03: 0
IGCC_04: 425
IGCC_05: 425
IGCC_06: 425
IGCC_07: 425
IGCC_08: 425

Objective: Total Study Costs:1: Mean: 24421.4227133067
Feasible Requirement: Total Study Costs:1: Std_Dev: 5614.3871222492
Feasible Requirement: Total Study Costs:2: Median: 23223.7005012319
Feasible Requirement: TailVar90: Final_Value: 35924.8641878857
Feasible Requirement: CVaR20000: Final_Value: 26183.2357784132
Feasible Requirement: Quint90: Final_Value: 32370.2595941873
Feasible Requirement: VaR90: Final_Value: 7948.83688088056
Feasible Requirement: Cst_Var: Mean: 5.01001288051045
Feasible Requirement: Max_Incr: Mean: 13.503317703262
Feasible Requirement: LO_MWa: Mean: 1016.67790085181
Feasible Requirement: LO_Cst: Mean: 25.4497985131799
Feasible Requirement: NLO_MWa: Mean: 1561.91236255434
Feasible Requirement: NLO_Cst: Mean: 23.278176520789
Feasible Requirement: Cnsv_MWa: Mean: 2578.59026340615
Feasible Requirement: Cnsv_Cst: Mean: 24.1821505178384


Simulation: 2

Values of Variables:
Cnsrvn_01: 25
Cnsrvn_02: 25
RM: 3000
CCCT_01: 610
CCCT_02: 1220
CCCT_03: 1830
CCCT_04: 3050
CCCT_05: 3050
CCCT_06: 3050
CCCT_07: 3050
…. Etc….
```

**Figure L-108: OptQuest Log**

Plan A dominates Plan B if Plan A has lower cost *and* lower risk then Plan B. The plans on the efficient frontier of those plans that are not dominated by any other plan. Along the efficient frontier, sorting by risk automatically sorts by cost. We illustrated this sorting by the arrows in columns AS and AV of Figure L-109. For the remaining plans, there generally is no way to simultaneously sort cost and risk. The report sorts the near-efficient plans and the remaining plans, therefore, merely by risk.

## Data Extraction And Spinner Graphs

A developer does not validate a strategic planning model that incorporates uncertainty the same way that he would most models. When a developer wants to validate the typical simulation model, he performs calibration of the model on a portion of historical data but withholds a portion of historical data for testing. Validation consists of checking the performance of the model against this test data. The situation is different for a long-term planning model. The future will differ from the past in ways that are predictable. For example, structural changes in the supply and demand of natural gas will affect future prices. New resources will similarly affect demand for natural gas, supply of electricity, and transmission power flows. Using data from the past would not be valid. Similarly, while some types of variation, like stream flows, may indicate future variation, they probably don't have any bearing on strategic uncertainty or risk. Strategic uncertainty deals with changes about which we have little current information, such as diminished stream flow due to climatic change, new regulation, or unforeseen changes in irrigation requirements.



| | A | B | C | D | E | AQ | AR | AS | AT | AU | AV | AW | BG | BH | BI |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ****************************************** | | | | | | | | | | | | | | |
| 2 | * Analysis of * | | | | | | | | | | | | | | |
| 3 | * OptQuest.log * | | | | | | | | | | | | | | |
| 4 | * with * | | | | | | | | | | | | | | |
| 5 | * Analysis of Optimization Run_L27A2.xls * | | | | | | | | | | | | | | |
| 6 | ****************************************** | | | | | | | | | | | | | | |
| 7 | Sim | Cnsrvn_Lo | Cnsrvn_Dis | RM | CCCT_C | GCC_CY1 | IGCC_CY1 | Mean | Std_Dev | Median | TailVaR90 | CVaR2[illegible] | Cnsv_Cst: | Mean | |
| 8 | 1706 | 0 | 5 | 0 | | 0 | 0 | 23647.44 | 6602.989 | 22295.37 | 37435.84 | 26851.5[illegible] | [illegible]2.61565 | F | |
| 9 | 1873 | 0 | 5 | 5000 | | 0 | 0 | 236[illegible]3.11 | 6379.034 | 22272.49 | 36[illegible]55.9 | 26707.6 | 22.48798 | F | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | [illegible] | 0 | 237[illegible].78 | [illegible] | 22396.39 | 36[illegible].42 | 26541.[illegible] | [illegible].38016 | F | |
| 122 | 1233 | 10 | 5 | 5000 | | 425 | 425 | 244[illegible]0.97 | 5596.721 | 23208.61 | 358[illegible]0.81 | 26168.4[illegible] | 22.92024 | F | |
| 123 | 1234 | 10 | 5 | 5000 | | 425 | 425 | 244[illegible]5.55 | 5593.984 | 23207.23 | 358[illegible]0.22 | 26171.7[illegible] | 22.91977 | F | |
| 124 | 1232 | 10 | 5 | 5000 | | 425 | 425 | 244[illegible]0.25 | 5591.099 | 23205.85 | 358[illegible]9.08 | 26175.3[illegible] | 22.91493 | F | |
| 125 | 948 | 5 | 25 | 5000 | | 425 | 425 | 24508.42 | 5569.806 | 23311.89 | 35870.65 | 26202.5[illegible] | 24.06349 | F | |
| 126 | 3 | 0 | 0 | 0 | | 0 | 0 | 23661.51 | 6599.311 | 22301.92 | 37450.84 | 26836.8[illegible] | 22.24873 | | x |
| 127 | 1726 | 50 | 5 | 0 | | 0 | 0 | 23847.44 | 6496.037 | 22455.33 | 37[illegible]8.75 | [illegible] | [illegible] | | [illegible] |
| [illegible] | 775 | 5 | 5 | 5000 | | 425 | 425 | 24420.24 | 5604.747 | 23205.11 | 358[illegible]7.48 | 26191.7[illegible] | [illegible]2.41363 | | x |
| 1500 | 912 | 5 | 5 | 5000 | | 425 | 425 | 24686.57 | 5485.664 | 23486.43 | 358[illegible]2.99 | 26243.5[illegible] | [illegible]2.25928 | | x |
| 1501 | 922 | 5 | 25 | 5000 | | 425 | 425 | 24459.83 | 5598.099 | 23261.39 | 358[illegible]1.38 | 26237.1[illegible] | 24.06979 | | x |
| 1502 | 1230 | 10 | 5 | 5000 | | 425 | 425 | 24467.54 | 5575.609 | 23260.49 | 35880.23 | 26198.7[illegible] | 22.90646 | | x |
| 1503 | 60 | 50 | 50 | 0 | 12[illegible] | 1700 | 1700 | 31340.27 | 6122.014 | 29994.17 | 44043.84 | 31386.0[illegible] | 29.59224 | | |
| 1504 | [illegible] | [illegible] | [illegible] | 0 | 12[illegible] | [illegible] | [illegible] | [illegible]878.93 | [illegible] | 29537.35 | [illegible] | [illegible] | [illegible].59777 | | |
| 2009 | 264 | 35 | 30 | 5000 | | 425 | 425 | [illegible]13.59 | 5386.828 | 23829.93 | 359[illegible]7.55 | 26329.[illegible] | 26.69841 | | |
| 2010 | 807 | 15 | 5 | 5000 | | 425 | 425 | 25090.18 | 5395.79 | 24027.38 | 35[illegible]85.2 | 26423.[illegible] | 23.24394 | | |
| 2011 | 630 | 0 | 0 | 5000 | | 425 | 425 | 24824.09 | 5489.656 | 23716.65 | 35963.71 | 26344.[illegible] | 21.46526 | | |
| 2012 | | | | | | | | | | | | | | | |

**Figure L-109: Plans, Arranged By Cost and Risk**

In lieu of traditional validation, therefore, the Council relies on decision makers' direct evaluation of futures. That is, witnessing individual futures, including all sources of uncertainty taken as a joint event, convinces decision makers and builds credibility. If decision makers find that the futures are realistic and the plans respond to the futures appropriately, they are apt to have confidence in the results.

The workbook L24DW02-f06-P.xls[37] contains the macro subRunPlans for running a simulation on a given plan and placing selected data from each of the 750 futures into specific worksheets. A collection of Excel graphs displays the data, including values for all sources of uncertainty in each period. A sample of these graphs appears as Figure L-7 through Figure L-11, starting on page L-12.

The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs."

The same workbook that creates the spinner graphs can also extract data for any cell in the portfolio model and for any set of plans, not just a single plan. The user can specify the plans to be subjected to the futures by pasting copies of the decision cells into the worksheet "Plans," as illustrated in Figure L-110. The macros in this workbook will

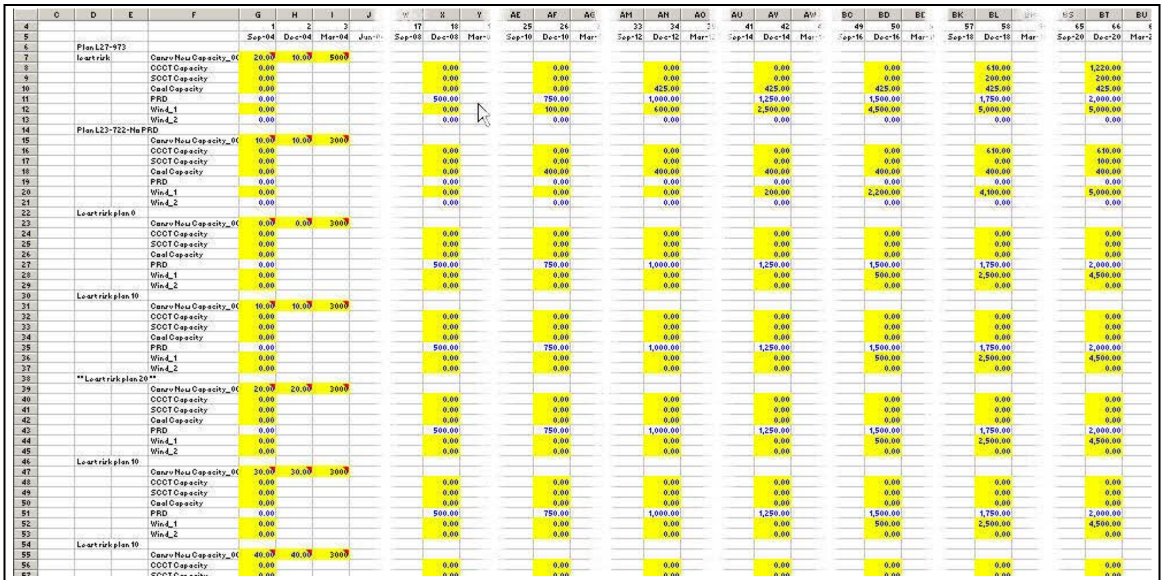


Figure L-110: Specified Plans Simulation Utility

perform a Monte Carlo simulation on each of these plans in turn and place the results in specified worksheets.

The data that the macro places into the selected worksheets comes from Crystal Ball forecast cells. To prepare a spinner graph, the user must prepare about 3200 forecast cells in the regional portfolio model worksheet. Converting a cell into a Crystal Ball forecast cell at a minimum requires the user to assign a unique name to the cell. The macro subAutoPaintForecasts in the workbook L24DW02-f06-P.xls does this work automatically. The macro reads instructions from the worksheet "Forecast Addresses", illustrated in Figure L-111. This worksheet identifies the rows and columns to be "painted with" forecast cells. The text in column B forms the names that the macro assigns to the forecast cells, together with the number of the column, and the address of the cell. Column H determines the names of the worksheets into which the macro places the resulting data. With a minor modification, this macro can also paint cells as Crystal Ball *assumption* cells.

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| 2 | | | long | long | long | long | long | string | |
| 3 | Description | Name | Start Row | Start Col | Width | Offset | Step | Root of New Worksheet Name | |
| 4 | natural gas price, 2004 $/MMBTU | NGP | 68 | 18 | 80 | 0 | 1 | NGP | |
| 5 | CO2 Tax, 2004 $/US short ton | CO2Tax | 74 | 18 | 80 | 0 | 1 | CO2Tax | |
| 6 | electricity price, independent term, 2004 $/MWh | EP_ind | 104 | 18 | 80 | 0 | 1 | EP_ind | |
| 7 | aluminum price, 2004 $/metric tonne | AL | 174 | 18 | 80 | 0 | 1 | AL | |
| 8 | electricity price, Western system, on-peak, 2004 $/MWh | EP_NP | 207 | 18 | 80 | 0 | 1 | EP_NP | |
| 9 | electricity price, Western system, off-peak, 2004 $/MWh | EP_FP | 219 | 18 | 80 | 0 | 1 | EP_FP | |
| 10 | annual reserve margin, MWa | RM | 295 | 22 | 73 | 0 | 4 | Other | |
| 11 | CCCT manifest capacity, MW | CCCT_cap | 455 | 18 | 80 | 0 | 1 | CCCT_cap | |
| 12 | SCCT manifest capacity, MW | SCCT_cap | 469 | 18 | 80 | 0 | 1 | SCCT_cap | |
| 13 | Coal manifest capacity, MW | Coal_cap | 483 | 18 | 80 | 0 | 1 | Coal_cap | |
| 14 | Wind manifest capacity, MW | Wind1_cap | 509 | 18 | 80 | 0 | 1 | Wind1_cap | |
| 15 | imports in addition to contracts, on-peak, MWh | Req_NP | 676 | 18 | 80 | 0 | 1 | Req_NP | |
| [illegible] | Unmet requirement[illegible] | [illegible] | [illegible] | [illegible] | [illegible] | 0 | 1 | Unmet_NP | |
| [illegible] | [illegible] | Shortfall_Av | [illegible] | [illegible] | [illegible] | 0 | 1 | Shortfall_Av | |
| 37 | lost-op conservation, MWa | LO_MWa | 1055 | 18 | 80 | 0 | 1 | LO_MWa | |
| 38 | non-lost-op conservation, MWa | NLO_MWa | 1056 | 18 | 80 | 0 | 1 | NLO_MWa | |
| 39 | Total study cost (NPV $M 2004) | study_cost | 1065 | 100 | 1 | 0 | 1 | Other | |
| 40 | lost-op conservation EOS, MWa | LOEOS_MWa | 377 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 41 | lost-op conservation EOS, 2004 $/MWh | LOEOS_Cost | 378 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 42 | non-lost-op conservation EOS, MWa | NLOEOS_MWa | 386 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 43 | non-lost-op conservation EOS, 2004 $/MWh | NLOEOS_Cost | 387 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 44 | total (lost op + non-lost op) conservation EOS, MWa | CnsvEOS_MWa | 389 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 45 | total (lost op + non-lost op) conservation EOS, 2004 $/MWh | CnsvEOS_Cost | 390 | 99 | 1 | 0 | 1 | CnsvEOS | |
| 46 | | | | | | | | | |
| 47 | | | | | | | | | |

Figure L-111: Specified Cells To Make Assumptions or Forecasts

## Calculations for a Particular Future

To verify the calculations in the regional model, the user must be able to drill down into the results to check calculations at the lowest level. Typically, when the user sees something that he or she does not understand, they will attempt to identify a plan in which that behavior is extreme. Using this plan, they look for a future in which the same behavior is evident. Depending on the issue, they may then need to trace the problem to a particular resource or period under that future. This final step requires that the user have access to the calculations taking place in every cell of the portfolio model worksheet for that plan and for that future.

As mentioned in the previous section (page L-110), single stepping with Crystal Ball does not reproduce the same sequence of futures that obtains from a simulation starting with a specific seed value for the random number generator. For this reason, it is necessary to run the simulation up to the future of interest. In simulation mode, however, the macros that the regional model uses to recalculate are not available to the user for experimentation and debugging. Therefore, the user must capture of the values of the assumption cells and put them in a copy of the regional model that the user can run independently, as described in section "Stand-Alone Calculation."

The user can run the Monte Carlo simulation up to the future of interest, and copy and paste the values of the regional model worksheet into a new worksheet. The workbook "L24DW02-f06-P.xls"[37] contains a macro, subCBAssumptionCopy, that transfers values from the cells in one worksheet to the corresponding assumption cells in a target worksheet. A dialog box interface prompts the user for the source and target worksheet names.

## Finding the Intersection of Two Feasibility Spaces

Occasionally, an analyst may see something surprising and counterintuitive when he compares two feasibility spaces. For example, suppose the user were comparing two feasibility spaces, the first with a base case set of assumptions regarding resource availability, and the second with resources that were constrained relative to the base case. Perhaps the CCCT capacity expansion resource is constrained from developeding to the same quantity (megawatts) in later years as under the base case. We would expect that the efficient frontier for the base case would dominate that of the constrained case. That is, we would not expect a plan from the constrained case would outperform the plans from the base case. A natural question to ask would be, "has the model changed?"

This question may not be so easy to answer. Perhaps the computers or software versions are different. It may be difficult to reproduce a specific plan from the base case. Even if the results for a particular plan matched, we have little reassurance that results would have matched if we chose another plan.

The macro sub_Compare in the module mod_ComparisionOfPlans.bas[37] permits the user to locate and compare identical plans from two feasibility spaces. It compares two feasibility space plan listings, such as that illustrated in Figure L-109. Specifically, for any matching plan the macro reports the difference in mean distribution cost and $TailVaR_{90}$. If these are identical for all of the matching plans, the user has greater confidence that the difference he is seeing is real and not merely the result of the change in logic or platform.

This macro has served a particularly important role for the Council. Recall that the modeling process uses optimization to find least cost plans given risk constraints. The primary reason for using optimization is to avoid simulating and comparing a very large number of plans[38]. Optimizing nonlinear, stochastic processes is a thorny technical problem, and initial conditions and early results can lead the optimizer to suboptimal search strategies. By comparing two feasibility spaces, the user gets a better idea of when and why the optimizer began a particular search strategy. A plan like the one just described in our example may be the result of such alternative strategy. The efficient frontier produced for the base case may simply not be optimal.

This situation is a reminder that the Council's model is no substitute for judgment. The analyst must study the feasibility space to determine whether alternative strategies near the efficient frontier exist and are beneficial. She must also question whether she can improve the strategies on the efficient frontier.

It has been the experience of the Council that, where the base case efficient frontier has proven to be suboptimal, intervention made at best marginal improvement. Occasionally, one resource of a given fuel type can substitute for another of the same fuel type, and the optimizer may tend to report only one of these along the efficient frontier. This has had little impact on the overarching strategy along the efficient frontier, however. These observations have provided the Council with overall confidence in the optimizer's efficient frontier.

## Stochastic Adjustment

Prices in the model derive from the Council's assumptions for long-term equilibrium prices[39]. For reasons discussed in Chapter 6, these equilibrium prices can be associated with the median price because there is equal probability of being above and below the median price. Some users may prefer, however, for the long-term equilibrium prices to match the price distribution's ***mean***. Because prices in the regional model use a lognormal distribution, however, the mean price is *higher* than the median price. (See Appendix P.)

To accommodate this situation, the model can apply a "stochastic adjustment" to the benchmark price. This adjustment, a number between zero and one, is chosen so that the distributions mean price matches the benchmark price. An example of a stochastic

[38] For the base case used in the final version (L28) of the plan, there are about to $5.1 \times 10^{24}$ possibilities.
[39] Because the median and the mean both described the final distribution of prices after any adjustment, we refer to the starting place as the "benchmark price." The benchmark price is typically the long-term equilibrium price.

adjustment for on peak wholesale electricity market prices appears in the second row of Figure L-112.

| | Series: Market Prices Independent Term_005 | | | | |
|---|---|---|---|---|---|
| Expected_Value_Set: Market Exp Price On-Peak 4x2 | 32.29 | 33.04 | 32.99 | 32.33 | 32.66 |
| Stochastic_Adjust_Set: Stoch Adj On-Peak 4x2 | 0.87 | 0.73 | 0.78 | 0.76 | 0.85 |
| Principal_Factor_Set: Reg Mkt Prc | -0.02037443 | 1.00 | | | |
| Data_Series: Mkt Prin Fac Level | 0.50 | | | | |
| | 0.007267999 | 1.00 | | | |
| Data_Series: Mkt Prin Fac Lin Growth | 0.00 | 0.07 | | | |
| Combined factors | -0.010187215 | -0.009678455 | -0.009678455 | -0.009678455 | -0.009678455 |
| Jump_Set: Elec Mkt_002 | 8.770426174 | 0.072691876 | 8.899814829 | | |
| | 16.07130502 | 0.100080134 | 11.46780741 | | |
| Combined Jumps | 8.770426174 | 173.850772 | 0.072691876 | 173.850772 | 220.5905142 |
| | 0 | 0 | 0 | 0 | 0 |

**Figure L-112: Stochastic Adjustment**

Each period typically requires a separate stochastic adjustment. The regional model workbook macro subTarget automates this process. The user may specify several different prices, say wholesale electricity price, natural gas price, and oil price, and simultaneously find stochastic adjustments for each of these in every period.

## Menu Bars

Menu bars are available for the portfolio model. These menu bars provide a simplified interface to many of the macros and utilities that this section describes. (See Figure L-113.) The menu bars are not in the regional model, because they interfere with distributed computation (see section ".")

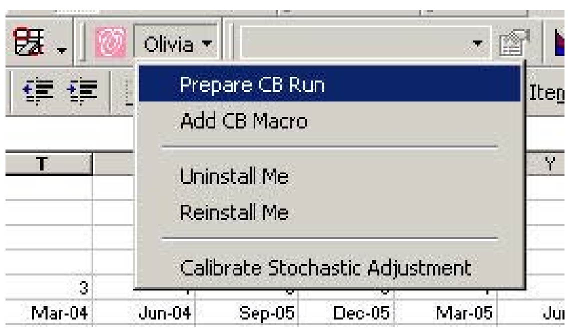



Figure L-113: Olivia Toolbar

# *Insights*

This section summarizes some of the insights and discoveries the Council has made using the regional portfolio model. Many of these insights arose out of paradoxes, behaviors that contradicted our intuition about how the model should behave. For this reason, the section presents these insights as the answers to a series of questions.

## General Paradoxes

**"The model suggests that we should build the resources we don't expect to use. It calls for conservation that is not cost effective and power plants that are not 'used and useful.' How can we justify this?"**

Building resources surplus to our requirements is analogous to buying insurance. We hope we never have to use it, but it would be foolish not to have the protection.

There are several differences between planning under uncertainty and planning with perfect foresight. Most strategic resource planning done today makes implicit use of the perfect foresight assumption. Whenever a plan assumes power plants recover their fully allocated costs or market price average around some long-term equilibrium level, planners are invoking perfect foresight.

Much of the planning today limits its treatment of uncertainty to what the Council would refer to as variation or variability. These are sources of uncertainty about which we have a great deal of information, such as hydro generation variability from year to year or the variation in loads due to weather. This kind of planning, however, does not embrace strategic uncertainty, the possibility that the underlying systems and markets themselves will change, perhaps dramatically and irreversibly. Embracing uncertainty means abandoning faith in averages and equilibrium. It means finding strategies that permit us to respond effectively and inexpensively to changing circumstances and protect us from the direst outcomes.

When we recognize that we need to protect our constituents from an uncertain future, insurance becomes useful. We hope that we will never have to use our insurance. We *hope* to lose money on the insurance, that we will forever pay a premium for our insurance and never have an opportunity to use it, *because if we ever do have to use our insurance, we will be worse off than we would have been otherwise*. The insurance merely reduces the magnitude of the damage; it does not eliminate it and it certainly should not reward us. (We would probably call such an expectation *speculation*, rather than risk mitigation.) Thus, some conservation and power plant capacity surplus to our anticipated need may not be used and useful, but it may be important protection.

Planning that does not embrace uncertainty not only fails to capture the insurance value of resources, but it in fact contributes to a riskier industry environment. Before the energy crisis, many utilities relied on the wholesale market instead of building their own resources. There are several reasons for this. The industry had surplus generating capacity and wholesale prices for electricity were low. Planners in the industry knew, however, that this situation would eventually correct itself. They relied on models, however, that computed long-term equilibrium prices for electricity. These planners elected to use a single price forecast for their analysis. Probably the single most meaningful price forecast is the long-term equilibrium price forecast, because it is the best estimate of where prices should return after any excursions, given a fixed set of assumptions. If one had to choose a single price forecast, this one would be the one to use. The problem with using a single price forecast, of course, is that it doesn't permit the planner to estimate the insurance value of resources. It does not tell the planner what kinds of risks he is incurring.

An insidious trap, however, lay in the fully allocated costs of some new resource setting the equilibrium price[40]. A CCCT is a typical candidate for new resource in the Pacific Northwest. If the planner is evaluating the utility-build decision using such a price forecast, it is unlikely that the utility build option will be cost effective. The new resource that sets the market price is the most cost effective in the region and is unlikely to be the unit that the utility is building. Even if the utility happens to be building the most cost-effective resource, however, there is no incentive to incur the risks associated with building a new resource if the planner believes the utility can purchase electricity from the market for a similar cost. Consequently, the utility does not build. Consequently, there is no gradual return of market prices to equilibrium. This produces a "boom and bust" cycle in electricity prices.

Cost-effectiveness levels change over time. Planning that ignores this will fail to capture the insurance value of resources, and in particular conservation. In the next section, this appendix documents how the shape of the supply curve for conservation and the changing cost-effectiveness level can make a policy of acquiring conservation in addition to that which appears cost effective today beneficial not only because of it reduces risk, but because the policy reduces *expected* cost.

**"The regional model tells us that we need resource surplus to our needs for insurance purposes. Why don't the combustion turbines and coal plants my utility wants to build support this objective?"**

The Regional Model tells us that having a little surplus is better than having a little deficit, but the principal strategic blunder would be to overbuild. Plans farther from the efficient frontier have higher levels of capacity.

Many utilities got themselves into difficulty during the energy crisis because of their exposure to the market. Twenty years ago, however, a crisis of equal if not greater proportion was visited on the region and much of the rest of the country when loads fell and ratepayers were exposed to fixed-cost risk. This is a source of risk that the regional model warns us may be a problem for the next decade. During the four years following the energy crisis, the region lost 2000 MWa of load and added 3000 MW of new power plants. Much of the load loss was from smelters that shut down. It is unlikely that most of these smelters will return to service. This 5000 MW is a significant portion of the 20,000 MW of regional load. The Council estimates that 3000 MW would probably have been sufficient to keep the region in balance during the energy crisis. Load growth in the region is approximately 300 MW per year, and new resources, such as the 500 MW Port Westward Project and portfolio standard wind, will continue to contribute to this surplus.

When it comes time to build for an energy reserve margin, the region has to be careful about the resources that it selects. A reserve margin criterion that only specifies how

[40] This is classical macroeconomics: equilibrium price equals long-term marginal cost.

much capacity to build surplus to requirements ignores economics and many important sources of risk. Confronted with a capacity reserve margin requirement, a utility will probably build a single-cycle combustion turbine (SCCT). On a dollar per kilowatt basis, this is the cheapest way to meet that requirement. A coal plant might be the cheapest way to meet an energy reserve margin requirement. Both of these fuels expose the utility to greater carbon emission penalty risk and fuel price risk, however.

**"Why are IPPs included in the region? My utility has a resource deficit, but there isn't sufficient transmission capacity to wheel IPP power to our load center."**

The focus of the regional model is economic efficiency and risk. Market prices across the western states do not deviate materially among themselves. Most of the time, they track each other closely. This means that a utility need not wheel power from a plant in order to reduce economic risk, because it can buy power in the market to meet its load center requirement and offset the cost of that wholesale spot power with the value of power used in a remote market. The economic effect is virtually identical to having a local power plant, selling into the market of the load center.

This is idea is not new; utilities have used this principle for many years. For example, Portland General Electric owns a portion of Colstrip Units 3 and 4 in Wyoming. While there are contracts to wheel this power to Portland, those contracts are counter-scheduled. When the Kaiser Mead and Columbia Falls aluminum smelter in eastern Washington shut down in response to federal buy-back offers in 2001, a remedial action scheme (RAS) shut down the Colstrip units to prevent instability on the Avista system. Power bottled up on the east side of the West-of-Hatway (WoH) transmission cut-plane. If the fiction of contract path transmission were true, and transmission lines were "electron pipes," there would be no reason for the Colstrip units to be taken down. The load situation in Portland certainly had not changed. The fact is, the Colstrip power is actually serving power loads and supporting the integrated power system east of the WoH cut-plane. Nevertheless, the Colstrip units remain a valuable economic hedge for PGE's customers against the more volatile market power purchased from the Mid-Columbia, and PGE accounts for the units as though the power meets Portland demand. Most utilities have similar arrangements.

**"Surplus conservation appears to have a significant benefit to the region. The benefit, however, far exceeds the product of market price and surplus conservation capacity. Where is this extra value coming from?"**

Modeling has revealed that early development of conservation can play an important role in moderating price volatility. Reducing price volatility reduces system cost. Conservation is uniquely suited to this task.

Early in regional model studies, the portfolio model used market value as the decision criterion for adding new resources. That is, when the model estimated that a resource would make money in the market based on the model's estimate of forward curves, it would proceed with construction of that resource. The exception to this situation, however, was conservation. Conservation has a slightly different decision criterion that caused continuous and early additions.

This situation effectively created a resource reserve margin. If a situation arose that created a price spike, this surplus of capacity mitigated the spikes. In fact, the value of conservation estimated by looking only at market price and the cost of the conservation would actually go down when the model added surplus conservation. Market prices lowered and conservation costs increased. Nevertheless, these plans performed better because the cost of serving load, a major cost component in the valuation equation, went down with lower market prices.

Conservation has certain advantages with respect to other resources as a source of energy reserve margin. One of these stems from the fact that, if conservation is to be developed into a significant resource, it needs to be developed continuously anyway. Whereas utilities can add power plant capacity on relatively short notice, conservation capacity must be added slowly over time, largely because the opportunities for securing conservation are constrained.

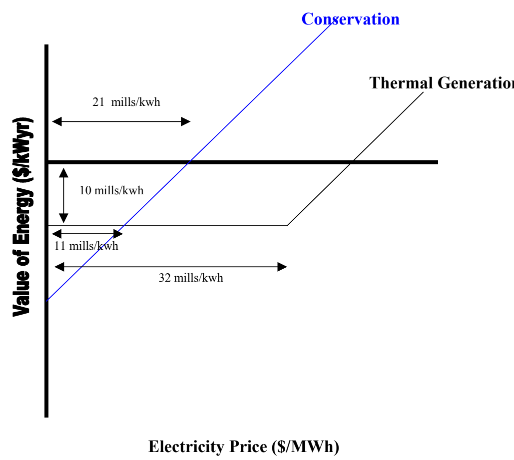



**Figure L-114: Supply for Conservation vs Dispatchable**

Another advantage of conservation is that it always contributes some value irrespective of market price. In Figure L-114, we assume a combined-cycle combustion turbine (CCCT) has a capital cost of 10 mills per kWh and a dispatch cost of 32 mills. It does not provide a positive net benefit until market prices exceed 42 mills. Assume that this CCCT is setting the market price, which would therefore be 42 mills. If this is the cost-effectiveness level of a supply curve for conservation that is linear between zero and 42 mills, the average cost of conservation would be 21 mills. Between 11 and 21 mills, both the turbine and the conservation would lose money, but the turbine would lose more money. Between 21 mills and 42 mills, the conservation is paying for itself, but the combustion turbine is not. Above 11 mills, conservation provides greater value than the CCCT. While some policymakers may be concerned that pursuing an aggressive program of conservation acquisition is risky when depressed market prices are likely in the future, this example suggests the opposite. Conservation would be the best solution unless market prices are extremely low, below 11 mills per kilowatt-hour. (And under that circumstance, lower purchase power costs for loads not met by conservation provide the utility a hedge against the extra cost.) This example, moreover, ignores the high-price risk mitigation value of conservation described in a previous paragraph.

In the past, system planners have regarded reserve margin primarily as a means to enhance system reliability. The economic and price effects of reserve margin have been largely ignored. The regional portfolio model identifies significant value in the price moderation effect of conservation. Others have seen this effect for renewables, as well. [**20**]

**"The regional model appears to find larger energy reserve margins attractive the further out in time we plan. Reserve margins have traditionally been expressed as some percentage of loads or a fixed level of energy surplus to requirements. Why does the regional model's surplus requirements grow so much faster than load growth?"**

One of the attributes of uncertainty is that it grows over time. As uncertainty grows, there must be a greater diversity of options and a greater availability (megawatts) of each option to cover contingencies. For example, assume we provide the regional model with only two candidates for new capacity: a coal plant and combustion turbine. There is greater uncertainty about loads and possible carbon penalty 20 years from today. It may also be likely that there will be high natural gas prices. Consequently, the best choice for the model is to plan for and site enough coal plant capacity and combustion turbine capacity to cover the entire load requirement. This may double the apparent amount of construction that the model is calling for. In fact, depending on the future, the owner would construct either one resource or the other, but probably not both.

A couple of related issue are the dependence of the regional model's plans – which specify options for construction – on uncertainty and the need to revise plans as that uncertainty resolves itself. The regional model specifies the risk-constrained, least-cost plans given today's view of uncertainty. Implicit in the plans is the assumption that decision makers must commit to siting and licensing today. For the most part, this is unrealistic. Before committing to plant siting and licensing for construction commencement ten years in the future, for example, there will be opportunities to review the plans to determine whether the siting and licensing costs are still warranted. Decision makers must use these opportunities to update information about assumptions and review plans before committing funds.

**"The efficient frontier sweeps out a fairly small range of cost and risk. Given the magnitude of costs going forward, why is this trade-off curve so small?"**

The primary reason the trade-off curve is small relative to the scale of costs in this study is that the regional model has no control over the choice of existing resources. While the model can choose resources going forward that reduce exposure to natural gas prices, for example, about 25% of the energy requirement will be met with natural gas in the future irrespective of what the regional model chooses.

We see in many of the sensitivity studies presented in Appendix P that the impact of uncertainties dwarfs the effect of resource choice. The efficient frontier, which may represent a trade-off of $500 million to $1 billion, moves between $6 and $10 billion if expected gas prices double. $CO_2$ emission penalties can have even larger impacts. Both of these affect the existing system, over which the model has no control. Perhaps it is useful to remember the relative scale of that which is controllable, compared to that which is out of our hands.

**"Market prices in the regional model do not behave as we would expect. For example, you are not building any resources in the future and loads are increasing. Nevertheless, electricity prices stay low. Moreover, if you increase import-export capability, market price volatility increases instead of decreasing. Access to greater imports increases reliability, doesn't it? How do you explain this?"**

A model that explicitly incorporates uncertainty behaves in ways that are counterintuitive to those who have used in deterministic models. This behavior is due to two terms: locality and modeling degrees of freedom.

Locality means the model is capturing behavior of local resources and loads, based to a large part on local prices for natural gas and other local parameters. This representation, however, ignores much of the world and many, perhaps most, sources of uncertainty. While local electricity prices depend on local loads, local hydro generation, and local natural gas prices, these factors describe perhaps half of the variation in electricity prices. As we saw during the energy crisis, factors completely outside of the region can determine our local electricity prices. Looking forward, it is easy to see that a California policy encouraging the building of surplus resources probably will affect local prices for electricity. Technology enhancements that may reduce loads and electricity prices are not represented explicitly anywhere in the regional model. For these reasons, a significant contribution to the price of electricity is an independent stochastic variable, intended to represent these factors in aggregate. This large source of uncertainty is unrelated to explicitly modeled, local factors. How can market prices remain low when loads are increasing in no resources are being built? Through non-local factors, such as purchases of inexpensive electricity, supplied by breakthrough solar photovoltaic technology or from conventional resources that are now surplus to depressed copper mine electricity requirements outside the region, for example.

Because of the first law of thermodynamics, energy supply and load must balance. Electricity price, which has the special independent term described in the previous paragraph, determines generation and must have an additive inverse among other parameters in the model. This is a mathematical degrees-of-freedom requirement. (See discussion of the section “RRP algorithm” beginning on page L-51.) In the case of the regional model, import-export capability is the dual to electricity market price. That is, given a market price that includes the independent term, import-export energy together with regional generation must match regional load requirements exactly. If electricity market price uncertainty is large, import-export capability must be large to accommodate the balance; small import-export capability accommodates only a small amount of electric price uncertainty. Having no import-export capability implies that there is only one price that balances system load requirements, that is, there can be no uncertainty about electricity prices. This explains the behavior to which the opening question refers.

To understand intuitively what is taking place in the regional model, think of the regional market as extending to the out-of-region market, via the transmission system. Much of the uncertainty comes from the out-of-region market. If the import-export capability is small, the exposure to this larger market is small. The converse is also true.

The duality between wholesale market prices and import-export levels is in a sense arbitrary. A modeler could choose variables other than import-export capability to maintain energy balance. For example, adjusting regional loads would establish balance. Alternatively, regional resources could have been manipulated through forced outage rates to achieve the same end. Using these mechanisms would have introduced the same questions about cause-and-effect, however.

Whenever we attempt to model closed systems, like transmission constrained power systems, there are conservation laws that constrain the degrees of freedom. Prices, for example, are a direct function of supply and demand in modeling. Similarly, variation of one parameter, say price, correlates perfectly with load or the sum of generation. This representation permits no freedom of any parameter from any other; all variables are dependent variables. Constraining parameters transfer variation on to other variables. If all but one variable is constrained, they all are. In our case, market price variation is dual to imports and exports.

From these observations, we conclude uncertainty models should aspire to feasible scenarios, not complete explanations. In engineering models, such as circuit diagrams, the initial conditions and the system characteristics determine the future state of the system. An analyst can explain all behavior in terms of the model and inputs. Within an uncertainty analysis, where much of the input is, by definition, unknown, the analyst does not have an explicit, detailed story that explains why stochastic variables assume the values that they do. He nevertheless must assure the behavior does not violate the laws of physics. The behavior of the stochastic variables should not conflict with what the decision maker believes is possible, although the decision maker may find the behavior highly unlikely. The decision maker must recognize the scope of possible influences.

## Conservation Value Under Uncertainty

As the previous section explains, conservation cost and risk mitigation originates from several sources, including conservation's contribution at low prices and the effect that early conservation development has on reserve margin and price volatility suppression. One of the discoveries that the Council made during studies under uncertainty was that the shape of the conservation energy supply curve could justify policies that would seem foolish if decision makers were to ignore uncertainty.

The following argument is somewhat long, but the basic idea is simple. Under certain circumstances, if the supply curve is nonlinear, the policy of acquiring more conservation than a cost-effectiveness standard would deem prudent can lower cost. Consider a simple world where there are only two market prices, $p_1$ and $p_2$, and these occur with equal frequency. (See Figure L-115) In this case, of course, the average price is between the two. Assume that these two prices fall on different segments of the supply curve for lost opportunity conservation, as shown.

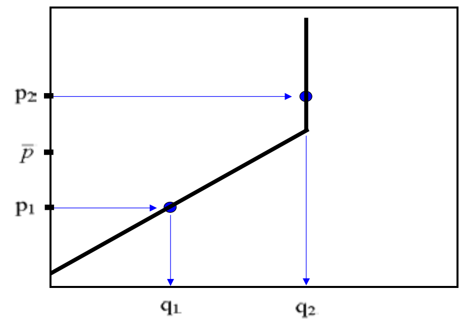



**Figure L-115: Nonlinear Curve, Market Prices**

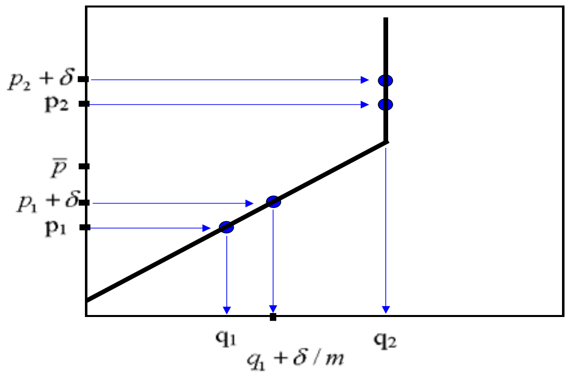



**Figure L-116: Supply Curve with Premiums**

Consider now the policy where we acquire conservation up to higher prices, $\boldsymbol{p_1+\delta}$ and $\boldsymbol{p_2+\delta}$. We obviously acquire more conservation than we would have without the premium when the market is at the lower price, $\boldsymbol{p_1}$. Because the supply curve is vertical at $\boldsymbol{p_2}$, however, the policy does not result in any additional acquisition at the price $\boldsymbol{p_2}$. The policy results in acquiring more conservation at cost that is below average. Figure L-117 shows the value of the policy as the shaded area. This figure uses the same cost and value assumptions, such as "no producers' surplus," that the appendix detailed in section "Supply Curves."

Several aspects of this example are unsatisfying. For example, conservation acquisitions must be borne over the life of the measure. This example does not address that. The remaining portion of this section, therefore, provides a more detailed example.

Before proceeding, note that this example is intended to illustrate how the policy we have just described *can* result in lower cost. This is not to suggest that it *must* result in lower cost. Whether this policy reduces cost depends in a sensitive fashion on assumptions about the shape of the supply curve, the time value of money, and other things that this example intentionally glosses over for the purpose of keeping the example a simple as possible.

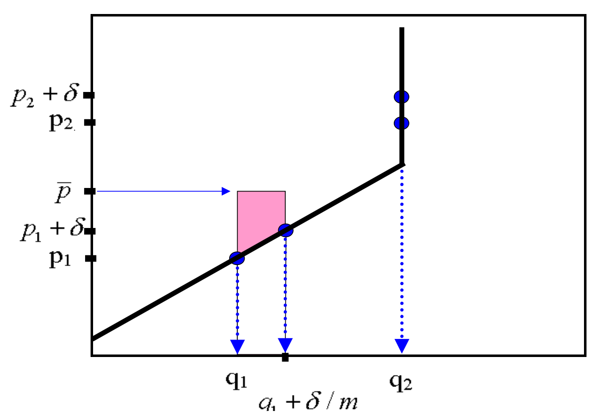



**Figure L-117: Value of the Policy**

In this example, we repeatedly referred to market price as a cost-effectiveness standard. This is a shorthand way of talking about whatever kind of cost-effectiveness standard would make sense to a decision maker. The Council has traditionally used a long-term equilibrium electricity price forecast produced by a spreadsheet model or by the Aurora model. That price effectively turns out to be the fully allocated cost of the least-expensive resource over the long term, typically taken to be a CCCT. This cost-effectiveness standard changes slowly, but its variation can still be quite large. In the late 1990s, this value would have been about \$20 per megawatt hour. During the energy crisis, it could have been hundreds of dollars per megawatt hour in the short term, but probably would have remained about \$20 per megawatt hour in the long-term. Today, with expectations for natural gas prices running about twice as high as they have historically, this value would be \$35-\$40 per megawatt hour. Irrespective of the nature of the cost-effectiveness standard, it is critical to recognize that there is variation and uncertainty in the cost-effectiveness standard over time. If that is recognized, the following example pertains.

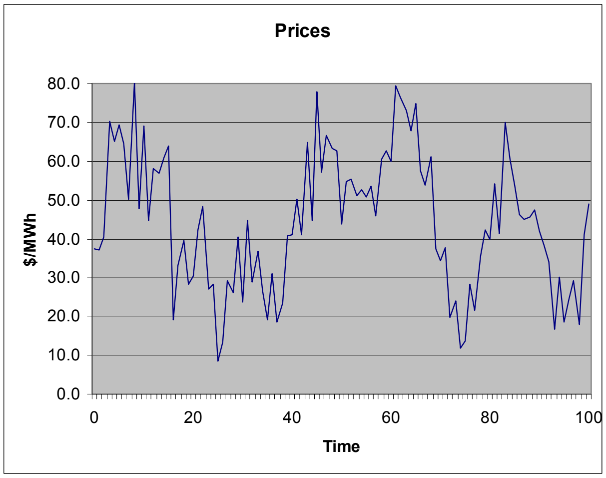



**Figure L-118: Prices**

Start by choosing a period with a representative distribution of prices (cost-effectiveness levels). This example assumes that prices are stationary over the long-term but have some variation around the average. Figure L-118 illustrates prices that this example will use, and Figure L-119 shows the frequency distribution of these prices. The period chosen, by definition, has prices representative of future periods, as Figure L-120 suggests. In Figure L-120, we take the effective life of the conservation measure to be some multiple, N, of this period. Over periods 2 through N, this example assumes that the distribution of prices, if not identical to that in the first period, has the same average as that in the first period.

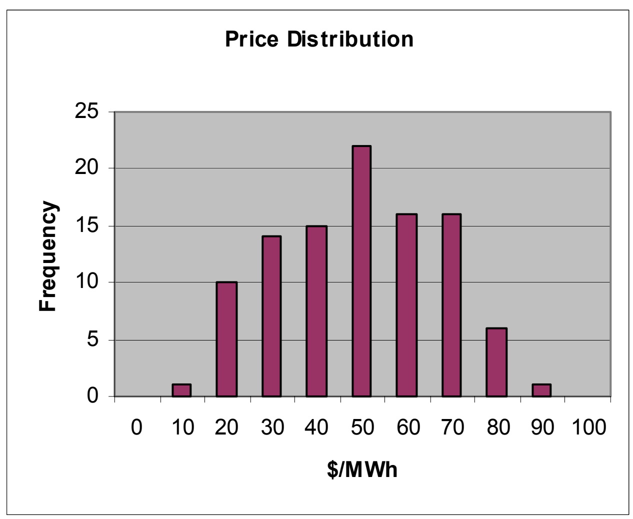



**Figure L-119: Distribution of Prices**

The conservation is a lost opportunity measure. In each period, potential conservation acquisition is represented by the supply curve in Figure L-121. This

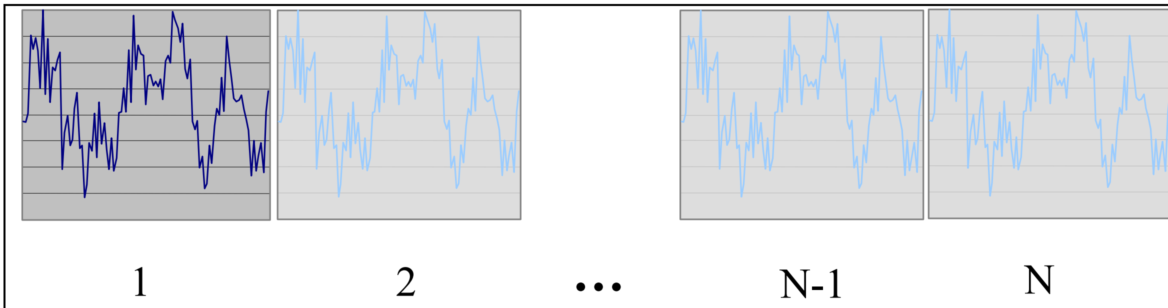



**Figure L-120: Prices over Time**

appendix's section "Supply Curves" details the technique for computing the amount of energy and the real levelized cost for the conservation from this supply curve.

During the period we have chosen, the example gatherers energy and cost according to the supply curve. In Figure L-122, the rate of acquisition of cost in the upper graph and of energy in the lower graph varies directly with the price. We note that the cost acquisition rate seems to be more sensitive to price variation than the energy acquisition rate, especially during periods of low prices, such as that identified as subperiod B in the figure. The energy and real levelized cost are present through the effective life of the conservation, which in this example we assume is identical to the economic life.

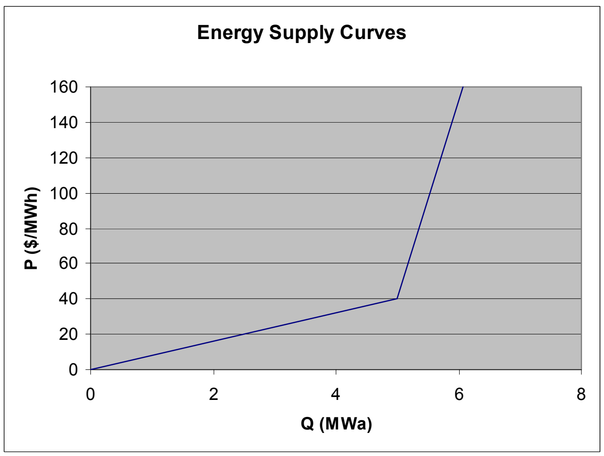



**Figure L-121: Supply Curve for Conservation**

The gross conservation value associated with the selected period is the sum of the acquisition rates over the selected period (just the cumulative height of the stacked acquisitions), times the average market price, times N-1. To see this, recall that the average market price over each of the N periods is identical, as Figure L-123 suggests. If the prices in period N are identical to those in period 1, the value the remaining life for each cohort *in* period N is unchanged *if moved to period **1***, as illustrated in Figure L-124. Note also that the *order* of the prices in period 1 does not affect the value, only the *distribution*. It is immaterial whether the process begins with a high or a low price.

A similar argument shows that the total cost of conservation acquired over the selected period is the sum of the acquisition rates for cost over the selected period, times N-1. The net benefit of conservation acquisitions over the selected period would then be the gross value minus this cost.

One of the assumptions this example makes to simplify calculations is that money has no time value. This example does not discount any of the cash flows.

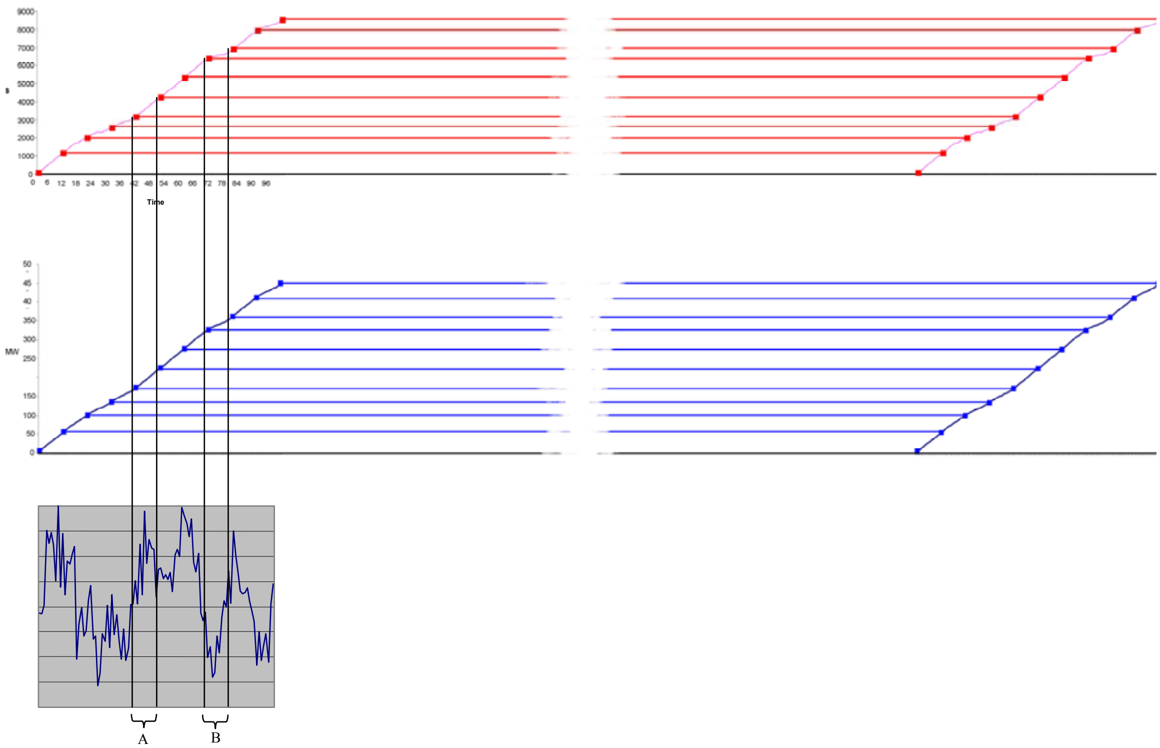



**Figure L-122: Conservation Additions**

We can summarize the above calculation of the net benefit of conservation acquisitions as follows:

$$V = \overline{p}\Delta q - \Delta c$$

where

$\overline{p}$ is the average market price

$\Delta q$ is the cumulative increase in quantity

$\Delta c$ is the cumulative increase in cost

These considerations demonstrate that gross value and cost of conservation acquired over the selected period are both proportional to the sum of the acquisition rates over the

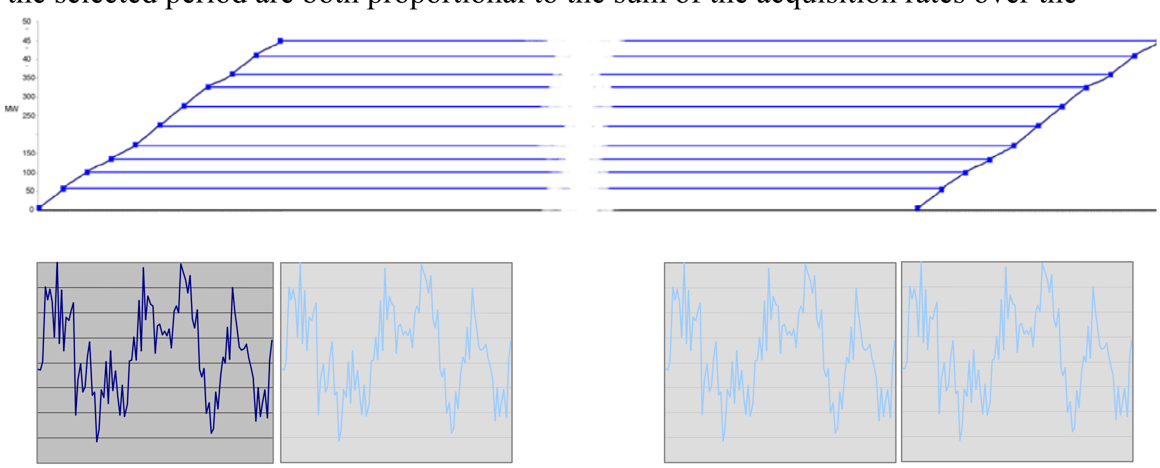


**Figure L-123: Value of Conservation**

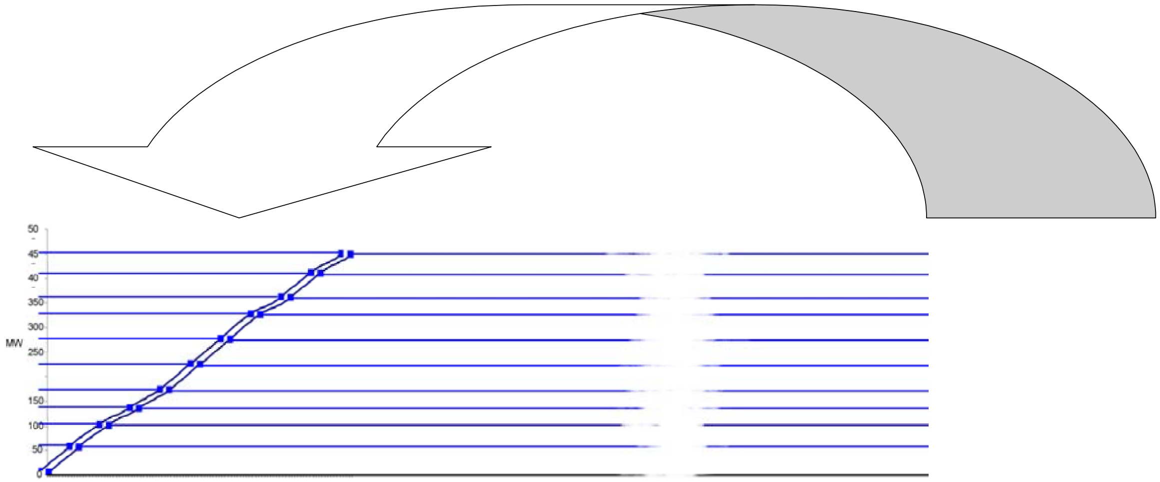
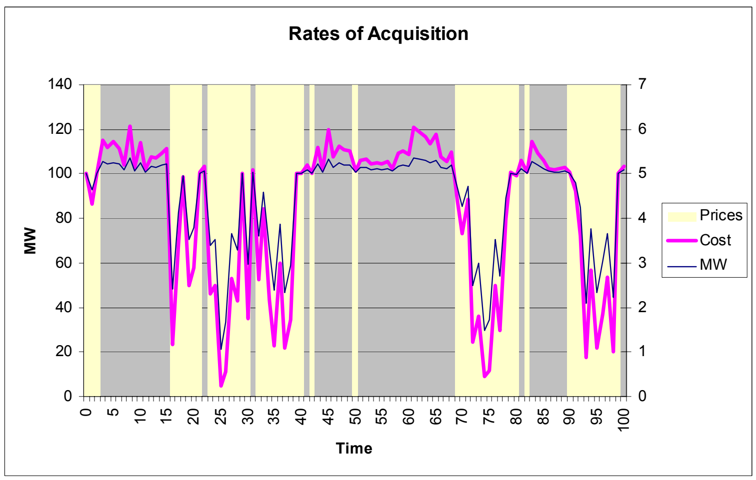



**Figure L-124: Rearranging the MW**

selected period. (The net benefit, of course, involves the average market price and is not so easily characterized.) Figure L-125 illustrates the rates of acquisition for cost and megawatts over the selected period. In this figure, the subperiods with prices that are below average are highlighted. As we would expect, cost and acquisition rates are much lower during these periods. We also note that the variation in the rate is much greater during subperiods of lower than average price.




Now consider the effect of the policy to acquire conservation up to 10 mills per kilowatt hour over market prices. The corresponding acquisition rates for costs and energy appear in Figure L-126. The policy of paying over market applies to all prices, including higher prices. What is striking, however, is that the acquisition of costs and energy during periods of high prices changes very little, while acquisition rates increase dramatically

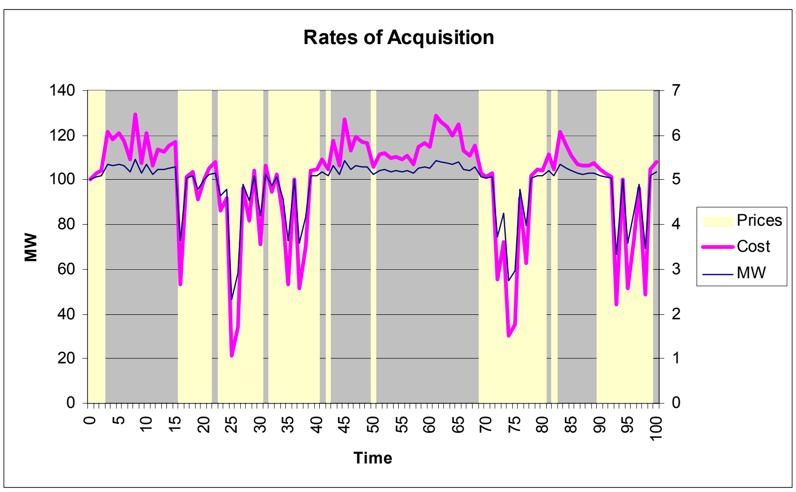



**Figure L-126: Acquisition with 10 mill/kWh Adder**

in times of lower prices. The differences in acquisition rates for energy and cost under the policy are highlighted in Figure L-127and Figure L-128, respectively. This behavior corresponds roughly to that in the example in Figure L-116, which opened this section.

Summing up rates of acquisition corresponds to finding the area under the curves in Figure L-125 and Figure L-126. Without the premium, cumulative energy acquisition is 449 MW, and cumulative cost acquisition is $8,553 per period. The average cost is 19.05 mills per kilowatt hour, about half of the average price for electricity, 44.36 mills per kilowatt hour. With the 10-mill premium, the cumulative energy and cost of course go up. The cumulative energy acquisition is 494 MW and the cumulative cost acquisition is $10,047 per period. The average cost increases to 20.33 mills per kilowatt-hour. Because we have acquired so many more megawatts at prices well under the average market price, however, the net value of conservation under the policy is greater. The net value of the policy is $520 per period, of 4.6% gain.

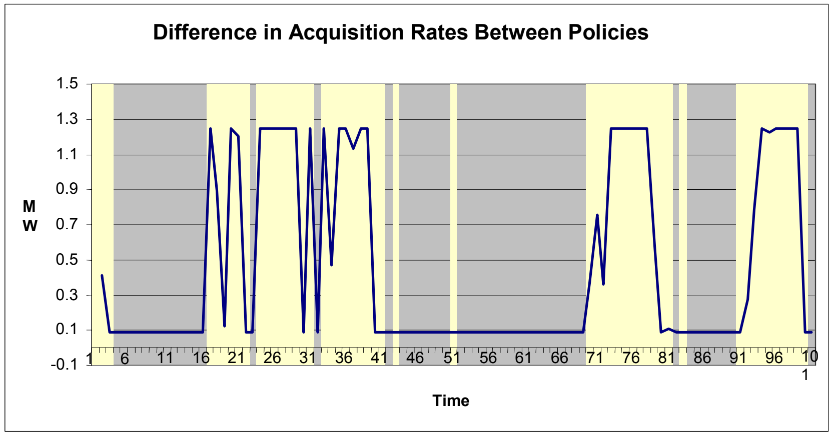



**Figure L-127: MW Difference with 10 mill/kWh**

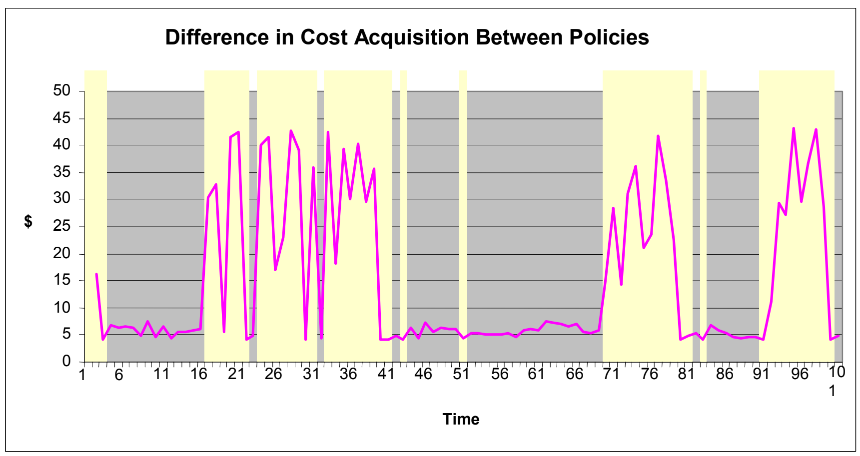



**Figure L-128: Cost Difference with 10 mill/kWh**

It is important to emphasize that the assumptions in this example are simple and not necessarily representative of existing circumstances. The purpose of this example is only to demonstrate how the shape of the supply curve could produce savings with a policy like the one this example uses. If the supply curve in this example were linear, there would be no net benefit. (Those readers who are becoming conversant in the supply curve cost computations will find the argument in Figure L-129.) Both supply curve non-linearity and uncertainty in cost-effectiveness levels are necessary for this effect.

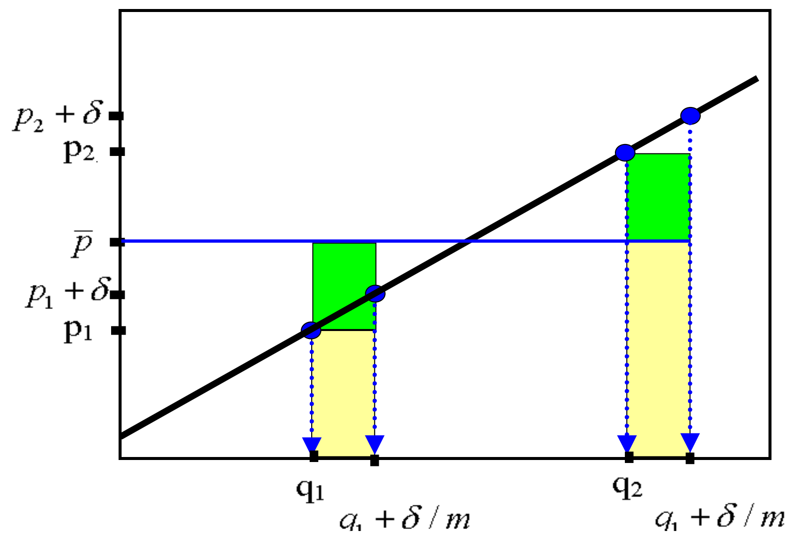



**Figure L-129: Comparing Cost Areas**

# Olivia

On February 6, 2002, the Council released Document 2002-01, "Issues for the Fifth Power Plan." This document solicited comments from the industry on issues that the Council was considering for inclusion in the plan. The first among these issues was, Incentives for Development of Generation:

> "The current market structure appears to have failed to provide adequate and timely incentives for adding new capacity to ensure power supply adequacy and to moderate price volatility. The Council proposes to assess existing incentives and disincentives for development of new generation and examine options available to encourage development that will moderate potential supply demand imbalances and price volatility. Options will be analyzed to determine their effect on prices, system costs, adequacy and reliability. If appropriate, the plan may recommend measures to address systematic problems or improve signals for market development."[41]

The Council considered possible incentives for new capacity and the issues each approach raised. Apart from the questionable efficacy of the various approaches, key

[41] Page 2 of NPPC Document 2002-01.

questions plagued all of the approaches, specifically who should be responsible and how can that responsibility be enforced? The Council was particularly cognizant of the limited formal authority granted to the Council by statute.

One approach that emerged during discussions of the regional portfolio model was to empower individual utilities to make resource selection decisions that reduce their risk and cost. This approach recognized the diverse and independent decisions that utilities make. It assumed that the real leadership the Council exercises stems not from the formal authority of the Council, but from the quality and objectivity of its ideas, data, information, and methods. Utilities have built and acquired resources to meet their own needs, subject to the approval of their commissions and boards. Their requirement for new capacity, not markets for capacity or administrative requirements, drove the demand for new power plants, including those constructed by IPP's. Arguably, utilities have always attempted to incorporate risk assessment into their resource acquisition decisions. Each utility approached risk somewhat differently, however, and consequently few standards have been forthcoming. This made communication with boards and commissions difficult. By providing these parties with concepts, methods, and tools for assessing risk and for assessing the risk mitigation value of resources, the Council would achieve the goal of improving regional reliability by empowering individual utilities to acquire resources that reduce their own risk. These concepts, methods, and tools might eventually lead to standards that would facilitate communication around risk management issues.

Ideally, the Council could hand its portfolio model to utilities and other interested parties. The regional model, however, is an Excel workbook. The selection of this platform makes it possible for those who wish to understand and reproduce the Council's results to do so easily. The associated transparency is consistent with the statutory objectives of the Council. The disadvantages of an Excel workbook, however, are several. If not carefully designed, a workbook will recalculate very slowly. A more serious problem is the structural inflexibility of calculations in a worksheet. For example, changing resources, redefining periods, modifying subperiods, and changing the attributes of resources can require significant restructuring. A utility that wanted to use the logic of the regional model to represent its system would probably need to rewrite the workbook. Because dozens of the workbook macros interact with the worksheets, a non-expert would likely introduce errors into the operation of the model.

To address these concerns, the Council designed Olivia. Olivia is a computer application, illustrated in Figure L-130, that writes workbook portfolio models. The user can characterize his utility's loads and resources, markets for electricity, imports and exports, and other relevant features with simple and high-level parameters. For example, he can type the monthly average energy by subperiod into a column of an Excel worksheet, and paste this into Olivia's database. He can define subperiods within a period and stipulate the number of hours in each. He can characterize a generation resource in terms of its capacity, heat rate, variable operation and maintenance, and most of the other parameters with which individuals who use production cost models are already familiar. He can specify correlations among sources of uncertainty and the kind of stochastic processes he wishes to use to represent the sources of uncertainty. Finally he can specify aspects of the portfolio model such as the layout, the cost and risk criteria he wishes to use, the utilities he would like included in the workbook (described in the previous section, "Portfolio Model Reports And Utilities"), and whether they should be accessible through a new menu bar in the workbook model.

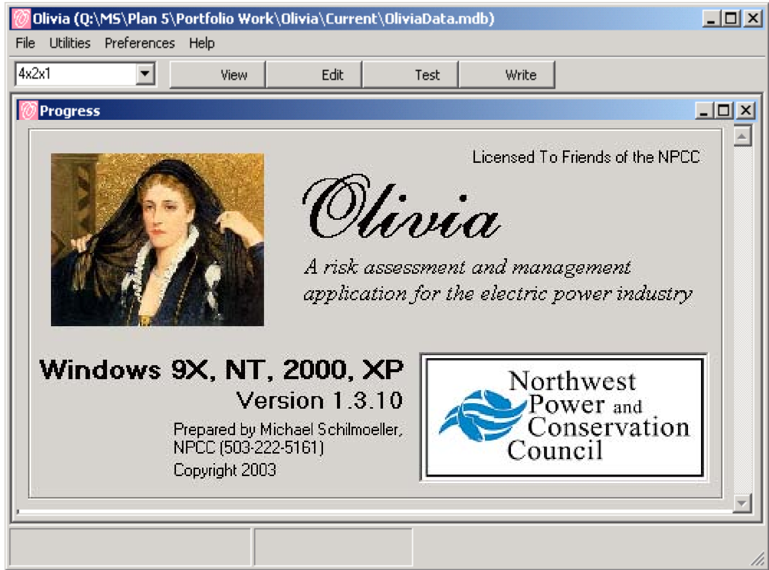



**Figure L-130: Olivia**

After pasting these data into Olivia's database, the user presses a button and Olivia writes the workbook. The workbook contains not only the data and formulas that the user specifies, but also any macros that the portfolio model needs to perform the simulation. Significantly, this workbook contains only those calculations and macros that this user requires, and no more, despite the richness of options and representations that Olivia can provide to users who need them. This keeps the workbook small and calculation as fast as possible.

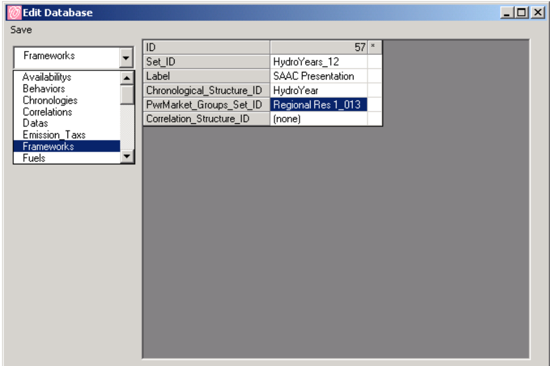



**Figure L-131: Editing Olivia's Database**

Olivia has editing features that make it easy to modify a portfolio model. The user can make these edits permanent or make edits to a "clone" of the model. Unless the user specifies otherwise, any updates to a model will automatically update all clones. This eliminates the potential for "revision sprawl" and models becoming de-synchronized. (See Figure L-131.) The editing interface features referential integrity, which guarantees that fields link to valid fields in other tables. (See Figure L-132.) There is also a utility that permits the user to test any changes he has made to a model to assure that they are legal and Olivia will interpret them properly.

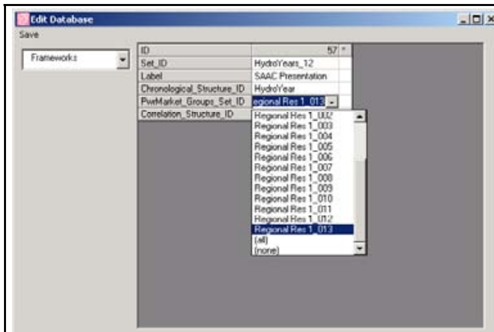



**Figure L-132: Referential Integrity**

This section is not a complete description of Olivia. As of this writing, Olivia is not in full production, although a version of Olivia extant in December 2003 produced the regional model used for this plan's analysis. The Council intends to release a production version of Olivia in Spring of 2005 and hold classes on its use shortly thereafter.

# Glossary

American option – an option that may be exercised up to expiration. (See European option, put option, call option.)

assumption cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains a value defined by a probability distribution's random variable.

availability – maximum power plant production, derated for planned outages (maintenance), but not forced outages (MW-period). Availability is synonymous with capability. Because the regional model expresses plant availability in average MW, maximum production is average capacity (MW).

call option – the right to buy the underlying asset by a certain date for a certain price.

capability – see availability.

CCCT – combined-cycle combustion turbine. A natural-gas fired combustion turbine that extracts additional efficiency from the turbine by capturing waste heat to create steam that assists generation. (See SCCT.)

CDF – Cumulative Distribution Function or Distribution Function. A function that specifies the probability that a variable's value falls at or below a given value.

cohort – a group has some descriptive factor, such as age, in common. In the regional model, all plants of a given type, e.g., SCCT, that are ready for construction in the same period are cohorts. They will respond to changing circumstances the same way and will remain in the same stage of development, production, or retirement throughout their lives.

Concept of Causality – relying on conditions that are strictly in the past (prior periods) to determine behavior in the current period.

DCF – discounted cash flow. A standard technique for the economic evaluation of projects, given the projects' associated cash flows. DCF analysis uses future free cash flow projections and discounts them to arrive at a present value, which is used to evaluate the potential for investment. Most often, DCF discounts cash flow at a weighted average cost of capital.

decision cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that the user controls. The reader may think of the value of these cells as representing the plan. The optimization program adjusts the decision cells in the regional portfolio model to minimize cost, subject to risk constraints.

distributed computation – partitioning computation into subtasks that are parceled out to several machines for processing and then reassembling the results in a manner that makes the final computation indistinguishable from that obtained from a single computer. Also referred to as "parallel processing."

dollars per kilowatt-standard year ($/kWstdyr) – the standard unit of fixed costs in the portfolio model. A standard year consists of standard months of exactly four weeks. (See "standard periods," below.) If a calendar year has 365 days, the $/kWstdyr is 336/365 or about 92 percent of the value of a project's $/kWyr. (See sections "Single Period" and "New Resources, Capital Costs, and Planning Flexibility" for discussions of standard periods and their use.)

DR – demand response. The voluntary curtailment of load, typically in response to prices. See chapter four and appendix H of the plan.

DSI – direct service industry, the community of industries that historically have been direct service customers of the Bonneville Power Administration. Aluminum smelters are a conspicuous DSI in the Pacific Northwest.

effective forced outage rate (EFOR) – percent of time that a power plant or other productive service is expected to be unavailable, due to unforeseen problems.

elasticity – The percent change in demand for a commodity divided by the percent change in the commodity's price

Energy Content Curve (ECC) – An operating guide to the use of storage water from reservoirs operated by parties to the Pacific Northwest Coordination Agreement. Gives 95 percent confidence of reservoir refill, given (projected) water conditions. The variable energy content curve (VECC) is the January-through-July portion of the energy content curve, based on the forecasted amount of spring runoff.

energy reserve margin – resource energy surplus to requirements. Unless otherwise qualified, this refers to the hydro year surplus in MWa (MW-years), assuming critical water hydrogeneration levels.

European option – an option that may be exercised only on the expiration date.

exchange option – an option to exchange a quantity of one asset, such as an mcf of natural gas, for another, such as a kWh of electricity.

feasibility space – a metric-free set of ordered pairs, where each pair represents a plan and the values of the two entries reflect the cost and risk of the plan. There is no metric because cost and risk typically are measured differently and are not comparable. Nevertheless, there is an efficient frontier of plans that are not dominated by other plans. (A plan is dominated by any plan with *both* lower risk and lower cost.)

forecast cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains statistical output of the model. The default color for these cells is turquoise. In the regional model, the primary forecast cell is the NPV cost for a plan under a 20-year future. Other forecast cells in the regional model, such as those that regional model macros assign risk values, serve to communicate data back to the OptQuest optimizer.

future – In the context of the regional model, a future is a set of circumstances over which the decision maker does not have control, such as requirements for electricity, prices for fuel, and stream flows that determine hydroelectric generation. (Appendix P addresses the complete list of uncertainties that give rise to a future in the regional portfolio model.) A set of samples for each of these, specified hourly over the 20-year planning horizon, comprises a single future.

GRAC – The Council's Generation Resource Advisory Committee

GTC – green tag credit. See Chapter 6 for a description and history of green tag credits.

IGC, IGCC – Integrated Gasification of Coal or Integrated Gasification Combined Cycle. A process for converting coal to gases suitable for combustion in power plants

IC – integration cost. Refers to costs necessary to integrate electricity from a power plant into an electric power system. Typical sources of cost are back-up or firming, shaping, and storage.

IPP – independent power producer. Synonymous with non-utility generation (NUG).

load-resource balance – see resource-load balance.

macro – a computer subroutine.

Monte Carlo simulation – Any method which solves a problem by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems which are too complicated to solve analytically. It was named by S. Ulam, who in 1946 became the first mathematician to dignify this approach with a name, in honor of a relative having a propensity to gamble (Hoffman 1998, p. 239). Ulam was involved with the Manhattan project to build the first atomic bomb, where physicists used the technique for evaluating complex integrals.

MWa – An average megawatt, typically the energy equivalent to one megawatt-year, although occasionally used rather loosely to refer to the average power rate (MW) over whichever period (day, month, quarter) is under discussion. Where it is important to avoid ambiguity, the appendix refers to the energy as a MW-year (MWyr), MW-month (MWmo), MW-quarter (MWqtr), and so forth.

NIPPC – Northwest Independent Power Production Coalition

O&M – operation and maintenance. When referring to the associated cost, may be either fixed (FOM) or variable (VOM).

On-peak, off-peak – refers to subperiods of loads and prices that are typically higher and lower, respectively. The regional model subscribes to the convention that on-peak hours are hours 7 through 22 (6AM to 10PM), Monday through Saturday, excepts for NERC holidays. Any hours that are not on-peak are off-peak. Because the regional model uses standard periods (see below), however, the model does not need to address variation due to days per month, Sundays per month, and holidays per month in cost and energy computation.

plan – The meaning of the term "plan" must be determined from context: 1) In the context of the regional model, a plan is that over which the decision maker has control, such as the siting and licensing schedule, earliest construction dates, and size and type of generation. In the regional portfolio spreadsheet model, the values of the worksheet's decision cells determine the plan. See the section "Parameters Describing the Plan" for a detailed description and explanation. 2) In the larger context, it may refer to the Council's Fifth Power Plan, either the Action Plan or the plan for resources beyond the five-year Action Plan.

put option – the right to sell the underlying asset by a certain date for a certain price.

PNUCC – Pacific Northwest Utility Conference Committee

production tax credit (PTC) – See Chapter 6 for a description and history of production tax credits.

resource-load balance – No standard definition of this term exists in the industry. In the context of this appendix, resource-load balance refers specifically to energy surplus to requirements on a hydro-year basis, assuming critical hydro water generation and weather-adjusted average load.

risk – No standard definition of this term exists in the industry. In the context of this appendix, risk always refers to the expected severity of *bad outcomes*. $\text{TailVaR}_{90}$ (see below) is the principal screen for risk in the regional portfolio model, although Council analysis considers other source of risk such as annual variation in power costs and exposure to market prices. This definition means predictability or uncertainty of costs, as measured by standard deviation, would not be a risk measure. (See the discussion of risk measures in Appendix P.)

RL costs – real levelized cost. See section "Real Levelized Costs," beginning on page L-16, for a detailed discussion.

SAAC – The Council's System Analysis Advisory Committee.

SCCT – Single- or simple-cycle combustion turbine. (See CCCT.)

scenario – a particular plan under a particular future. See the definitions of "plan" and "future."

spinner graph – A collection of Excel graphs display the data for a scenario, including values for all sources of uncertainty in each period. The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period and for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs." See section “Data Extraction And Spinner Graphs,” beginning on page L-117, for details.

standard period, standard month, standard quarter, standard year – any period based on the standard month, which has exactly four weeks (1152 on-peak hours, 864 off-peak hours). There are three standard months per standard quarter and four standard quarter (12 standard months) per standard year. See section “Single Period,” beginning on page L-11, for details.

$TailVaR_{90}$ – The average of the ten percent worst outcomes. In the regional model, the outcomes are NPV 20-year system costs for operation and forward-going fixed cost, including that for new construction. See Appendix P for details.

Twilight Zone, TLZ – a region in the regional portfolio model where computations typically are iterated several times for each subperiod or region. See section “Logic Structure,” beginning on page L-6, for a more specific description.

UDF – A Microsoft Visual Basic for Applications (VBA) user-defined function. These inhabit worksheet code modules, workbook code modules, and VBA standard modules (in contrast with VBA class modules). All regional portfolio model UDFs occupy standard modules.

valuation cost estimate – A technique for computing variable costs by referencing the gross value of each resource and the gross cost of meeting requirements to the price for marginal purchases and sales. The standard price used in the regional portfolio model is the wholesale market price for electricity. See section “Valuation Costing,” beginning on page L-13.

# Index

# References


**1** Glover, F., J. P. Kelly, and M. Laguna. "The OptQuest Approach to Crystal Ball Simulation Optimization." Graduate School of Business, University of Colorado (1998). Available at http://www.decisioneering.com/optquest/methodology.html ;
M. Laguna. "Metaheuristic Optimization with Evolver, Genocop, and OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/comparisons.html; and
M. Laguna. "Optimization of Complex Systems with OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/complexsystems.html

**2** Jeff King, NPCC, Tuesday, 4/4/2005 11:12 AM, email Subject: "RE: Appendix L," attachment AppL_050311JKcmts 040405.doc. "Perhaps unfortunately, the levelized cash flows that I supplied were based on a constant mix of developer (20% COU, 40% IOU and 40% IPP), and levelized using the blended after-tax cost of capital of these (4.9%). The resulting levelized fixed costs for a conventional coal and wind plants are about 9% and 4% greater, respectively, using these assumptions (the per MWh difference would be less because of the lower capacity factor of wind). – JK"

**3** Direct Calculation of Expected Value.doc

**4** Deriving_option_greeks.TIF and Derivative of call wrt strike.TIF

**5** The value of 6000MW was established by Council Staff analysis of intertie loadings. See, e.g., Dick Watson, intertieloading.xls, August 13, 2004.

**6** Terry Morlan, Ph.D., NPCC, Wednesday, June 23, 2004, Notes_L14.doc.

**7** Worksheet qry_041101_AppM_02 of Appendix M_04.xls

**8** Original Geneys model output is in System.out. The same subdirectory holds all the Genesys input and output files. See also Notes on comp_040626.doc for fundamental information about the database and queries and Notes.doc and Notes_Update_041103.doc for revisions. The database Appendix M.mdb and it successors are spawned from the comparison database, Comparison_040626.mdb. This latter database was originally in the subdirectory ..\Portfolio Work\Olivia\Calibration and Verification\Loads & Resources (LR) Studies\Portfolio vs LR balance 031030.

**9** Jeff King, NPCC, Tuesday, April 27, 2004 5:15 PM, *email* Subject: "GEBESYS genres list," [SIC] attachment FOR_040502.xls

**10** Worksheet "tbl_041110_Resources_in_L25" of Appendix M_04.xls

**11** Worksheet "Calc RPS" of Appendix M_04.xls

**12** Worksheet "IPP calculations" of Appendix M_04.xls

**13** MJS_Comments_041116.doc

**14** Worksheet "New Resources" of Appendix M_04.xls

**15** Worksheet "Construction Costs" of ConvertingOvernightToPeriodCosts_v06.xls

**16** The original energy allocation are from the workbook AllSectorSupply.xls worksheet "All Sector Supply," from Tom Eckman, Fri 1/16/2004 5:17 PM, email "Conservation Supply Curve Data." These calculations are from L8.xls ( see Notes on L7.doc ). See also Conservation Energy Allocation Reconstructed.xls for the simplified calculation that appears in this appendix.

**17** Workbook AllSectorSupplywithSysTDValue_L21.XLS

**18** Contracts data originally from Tim Misley, BPA, *email* Friday, August 27, 2004 3:22 PM, subject: "RE: Conversation with Tim Misley." Figure data from MSchilmoellerRegionalContracts_MJS.xls. The computation of the MWa for the regional portfolio model is in the worksheet "Contracts for Portfolio Model". Most of the data that went into preparing the workbook derives from the database Contract Data_03.mdb. See the database table "## Comments and Instructions ##" for an embedded MS Word document describing the more technical data transformations.

**19** Workbook States.xls permits a user to calculate the number of states for the choices available. It accounts for the reduction in the number of states for the constraint that no plants may be "un-built" after construction.

[20] See, for example, Paul Komor, Platts Research and Consulting, "Hedging Energy Price Risk with Renewables and Energy Efficiency," ER-04-12 Strat, September 2004.

# Global Climate Change Policy

A significant proportion of scientific opinion, based on both empirical data and large-scale climate modeling holds that the Earth is warming due to atmospheric accumulation of carbon dioxide ($CO_2$), methane, nitrous oxide and other greenhouse gasses. The increasing atmospheric concentration of these gasses appears to be largely from anthropogenic causes, in particular, the burning of fossil fuels. The effects of warming may include changes in atmospheric temperatures, storm frequency and intensity, ocean temperature and circulation, and the seasonal pattern and amount of precipitation. Possible beneficial aspects to warming, such as improved agricultural productivity in cold climates, on balance appear to be outweighed by adverse effects such as increased frequency of extreme weather events, flooding of low-lying coastal areas, ecosystem stress and displacement, increased frequency and severity of forest fires and northward migration of warm climate disease vectors. While the occurrence of warming and the general nature of its global effects are generally agreed upon, significant uncertainties remain regarding the rates and ultimate magnitude of warming and its effects.

The regional effects of climate change are more uncertain. Global models seem to agree that Northwest temperatures will be higher, but they disagree regarding levels of precipitation. Current thinking by Northwest scientists leans towards a warmer and wetter climate. The proportion of winter precipitation currently falling as high elevation snow is expected to decline and peak runoff expected to shift from springtime to winter. Summer stream flows would decline as a result of loss of snowpack. Warming would lead to a relative reduction in winter peak electricity demand and an increase in the frequency and intensity of summer peaks. The possible effects of climate change on the hydropower system are discussed in Appendix N.

Nationwide, the electric power system is a prime contributor to the production of $CO_2$, producing about 39 percent of U.S. anthropogenic $CO_2$ production in 2002[1]. Any meaningful effort to control greenhouse gas production will require substantial reduction in net power system $CO_2$ production. The most economically efficient means of achieving this likely to be through a combination of improved end use and generating plant efficiencies, addition of generating resources having low or no production of $CO_{2,}$ and $CO_2$ sequestration. Because it is unlikely that significant reduction in $CO_2$ production can be achieved without some net cost, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing.

Analytical consideration of the effects of climate change requires plausible estimates of the timing and magnitude of possible climate change actions. The approach used in this plan to capture the uncertainties of climate change policy was to separate the highly uncertain political factors (the probability and extent of actions being undertaken to control greenhouse gasses) from factors more subject to analysis (the cost of offsetting a ton of carbon dioxide).

The current state of climate change policy was summarized for the Council in April 2004 by Dr. Mark Trexler of Trexler Climate + Energy Services. Dr. Trexler noted that while the United States has not ratified the Kyoto Climate Protocol which establishes targets for reduction of

[1] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks1990 - 2002. April 2004.

greenhouse gas emissions, there is a good deal of climate policy action both in the US and internationally. Canada, for example, has ratified the Kyoto protocol, and compliance is a significant factor in Canadian energy policy. Elsewhere, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008[2].

Here in the United States, many states have or are developing climate change mitigation strategies. Oregon, Massachusetts, New Hampshire and Washington require partial offsets of $CO_2$ produced as a result of power generation.[3] The governors of the West Coast states, through the West Coast Governors' Global Warming Initiative have initiated an effort to develop common regional policy. California has recently adopted regulations that will require automakers to begin reducing the $CO_2$ production of vehicles sold in California by about 30 percent, beginning in model year 2009. Nationally, the United States Senate in late 2003 came within a few votes of passing the McCain-Lieberman Climate Stewardship Act that would have established a cap and trade system for the United States.[4] $CO_2$ reduction appears to be one of the primary drivers of efforts to reauthorize the federal renewable energy production credits and to expand state renewable portfolio standards and other renewable energy incentives. Finally, corporations increasingly are recognizing the likelihood of global climate change and the need to control greenhouse gas production[5].

Dr. Trexler presented three scenarios for the evolution of climate change policy in the United States. One scenario portrayed collapse of efforts to implement climate change policy. He viewed the probability of this to be low. A second scenario looked at the likelihood that a combination of factors would generate the political will to seriously tackle climate change. He viewed the probability of this as "modest" although perhaps somewhat greater than the probability of total collapse of climate change mitigation efforts. The third scenario was one that postulates that the issue will not go away and that there will be continue to be efforts to enact mitigation policy. He viewed the likelihood of this scenario to be high.

The Council's estimates of the cost of $CO_2$ offsets were guided by current state $CO_2$ offset experience, the conclusions of a Council-sponsored workshop held in May 2003, a June 2003 MIT study of the cost of implementing the McCain-Lieberman proposal[6] and an August 2003 MIT study of the costs of $CO_2$ sequestration[7]. A cap and trade allowance system, as called for in the McCain-Lieberman proposal and as used for a number of years for control of sulfur emissions, appears to be the most cost-effective approach to $CO_2$ control. However, to simplify modeling, a fuel carbon content tax was used as a proxy for the effects of climate change policy, whatever the means of implementation. The results are believed to be representative of any approach to control $CO_2$ production using carbon-proportional constraints on both existing and new generating resources.

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[2] Define Cap and Trade
[3] Reference these actions.
[4] S139
[5] "Global Warming: Why Business is Taking it so Seriously" Business Week August 16, 2004.
[6] Massachusetts Institute of Technology Joint Program on the Science and Policy of Global change. Emissions Trading to Reduce Greenhouse Gas Emissions in the United states: The McCain-Lieberman Proposal. June 2003.
[7] Massachusetts Institute of Technology Laboratory for Energy and the Environment. The Economics of CO2 Storage. August 2003.

The estimates of $CO_2$ control costs from these sources are very wide. The Oregon and Washington offset requirements for new generating resources include a provision whereby a developer can pay a deemed fee for each ton of $CO_2$ required to be offset. These payments currently amount to about \$0.87 per ton $CO_2$ for Oregon and \$2.10 per ton $CO_2$ for Washington. It is generally acknowledged that actual offset costs are double to triple the Oregon rate. The MIT report on the costs of compliance the Climate Stewardship Act provide a series of time-dependent estimates based on various assumptions regarding implementation. These range from \$0 to \$39 per ton $CO_2$ in 2010, \$10 to \$70 per ton $CO_2$ in 2015 and \$13 to \$86 per ton $CO_2$ in 2020. The Council workgroup estimated offset credits on the international market to range from \$5 to 10 per ton $CO_2$ in the 2005 - 2013 timeframe and \$20 to 40 per ton $CO_2$ from 2010 - 2025. Finally, the MIT study on the costs of $CO_2$ sequestration estimated costs ranging from \$2 to \$23 per ton $CO_2$ for various forms of geologic sequestration. Not included in this latter estimate was the cost of $CO_2$ separation at the power plant or possible offsetting revenues from enhanced petroleum or natural gas recovery.

# Effects of Climate Change on the Hydroelectric System

## SUMMARY

The Council is not tasked, nor does it have the resources to resolve existing uncertainties associated with global warming. Currently, there is still much debate surrounding the data, although a preponderance of scientific opinion asserts that the Earth is warming. The science has gotten stronger over the last 15 years and many uncertainties have been resolved. And although it appears that this trend is likely to continue, some uncertainties remain.

While the Council cannot resolve these issues, it does have the obligation to investigate potential impacts of climate change to the power system and to recommend mitigating actions whenever possible. While global warming cannot be modeled with precision for the Pacific Northwest, it is possible to make general predictions about potential changes and, as a result, recommend policies and actions that could be adopted and implemented today to prepare for potential future impacts.

Many nations and government agencies are already taking actions. Canada, for example, has signed on to the Kyoto agreement. Also, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008. Oregon, Massachusetts and New Hampshire require offsets for new fossil power plants and Washington legislators have recently enacted a carbon dioxide offset requirement for new power plants, similar to Oregon's.

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

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

- Putting greater flood control pressure on storage reservoirs and increasing the risk of winter flooding;
- Boosting winter production of hydropower when Northwest demands are likely to drop due to higher average temperatures;
- Reducing the size of the spring runoff and shifting its timing to slightly earlier in the year;

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

There also are potential impacts away from the river system, particularly for the electricity industry. Current scientific knowledge holds that global warming largely results from increased production of carbon dioxide and other greenhouse gasses due to human activities. Because of the widespread use of fossil fuels to produce electricity, the electricity industry worldwide is a principal contributor to the growing atmospheric concentration of carbon dioxide and would be affected by any initiatives to reduce carbon emissions.

The Council has used its resource portfolio model to look at the potential effects of control polices aimed at reducing greenhouse gas emissions on the relative cost-effectiveness of resources available to the Northwest. This involved posing different scenarios about the probability, timing and magnitude of carbon control measures and assessing their effect on different portfolios in terms of cost and risk. This analysis may also shed light on the value of various strategies to address climate change impacts.

The Council's electricity price forecasting model, AURORA©, is being used to assess the possible impact of carbon dioxide control measures on electricity prices and what changes in the composition of the generating resource mix it might induce.

The effects of the uncertainty surrounding a potential carbon tax have been incorporated into the Councils portfolio analysis and have appropriately influenced the recommended resource strategy and action plan. Further details of that analysis are provided in the main section of the power plan and in appendix M.

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

## BACKGROUND

Over the last century or so, the Earth's surface temperature has risen by about 1 degree Fahrenheit, with accelerated warming during the past two decades. The ten warmest years have all occurred in the last 15 years. Of these, 1998 was the warmest year on record. Warming has occurred in both the northern and southern hemispheres, and over the oceans. Melting glaciers and decreased snow cover further substantiate the assertion of global warming and appears to be more pronounced at higher latitudes. Figure N-1 below illustrates the warming trend, showing global temperatures from 1880 to 2000.

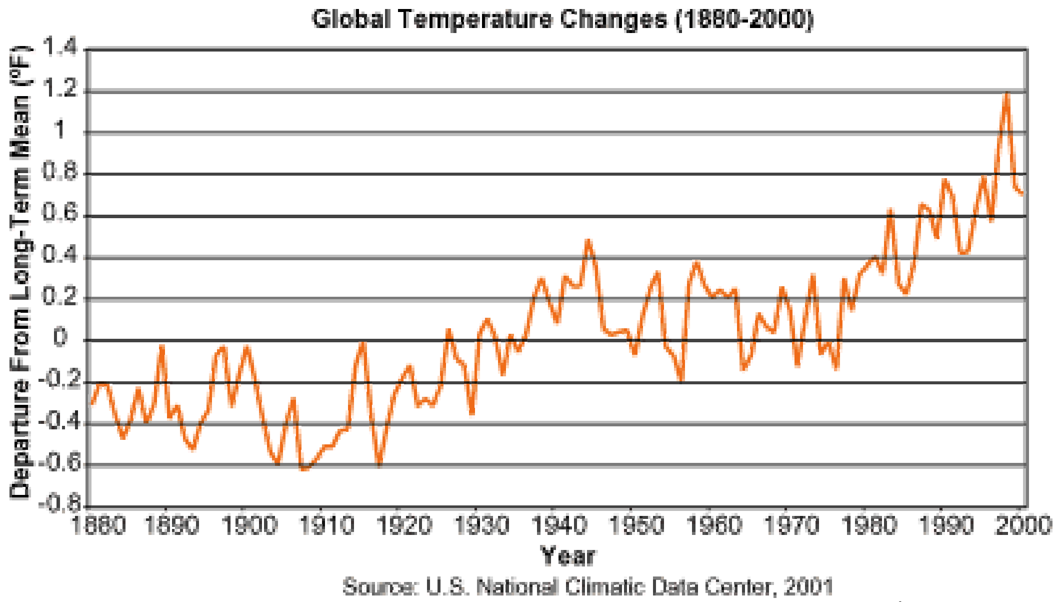


**Figure N-1: Global Temperature Changes (1880-2000)**[1]

Two rather obvious questions arise related to the data in Figure N-1. First, is this rise in temperature statistically significant (i.e. is the warming trend real?) and, if it is, what are its causes? Secondly, what potential impacts might global warming have and are there mitigating actions that we can take? While the first question is scientifically very interesting and is of great importance to Northwest inhabitants, the Council is not tasked to explore or debate this issue. Rather, the Council's efforts are directed toward the second question. More specifically, it must assess potential Northwest impacts of global warming and determine what mitigating actions are required to continue to protect, mitigate and enhance fish and wildlife populations, while maintaining an adequate, efficient, economic and reliable power supply for the Northwest. However, before moving on to a discussion of potential Northwest impacts and mitigating actions, the debate surrounding global warming will be briefly examined.

## Is Global Warming Real?

There is much anecdotal evidence of increasing temperature. Over the last 20 years, we have observed retreating glaciers, thinning arctic ice, rising sea levels, lengthening of growing seasons (for some), and earlier arrival of migratory birds. The northern hemisphere snow cover and Arctic Ocean floating ice have decreased. Sea levels have risen 8 to 10 centimeters over the past century, as illustrated in Figure N-2. Worldwide precipitation over land has increased by about one percent and the frequency of extreme rainfall events has increased throughout much of the United States. Figure N-3 shows that in 1910 about 9 percent of the U.S. experienced extreme rainfall compared to about 11 or 12 percent by 1990.

[1]Source: U.S. National Climatic Data Center, 2001

A cursory look at the temperature data in Figure N-1 indicates that there has been a warming trend and that it appears to be accelerating. However, the average change in temperature over the last century has been about one degree Fahrenheit, which may arguably be smaller than the accuracy of early measuring devices. It is also not clear how many geographical data points were available in the early years. (Recall that the data reflects average surface temperature over the entire Earth). Other things to consider are rare natural events, such as large volcanic eruptions or serious weather events that may have increased the greenhouse effect sporadically over the years. Such events may explain (at least in part) some of the year-to-year variation in the curve in Figure N-1. But, before further discussing the uncertainties surrounding global warming, it would be beneficial to understand what scientists believe is the cause.

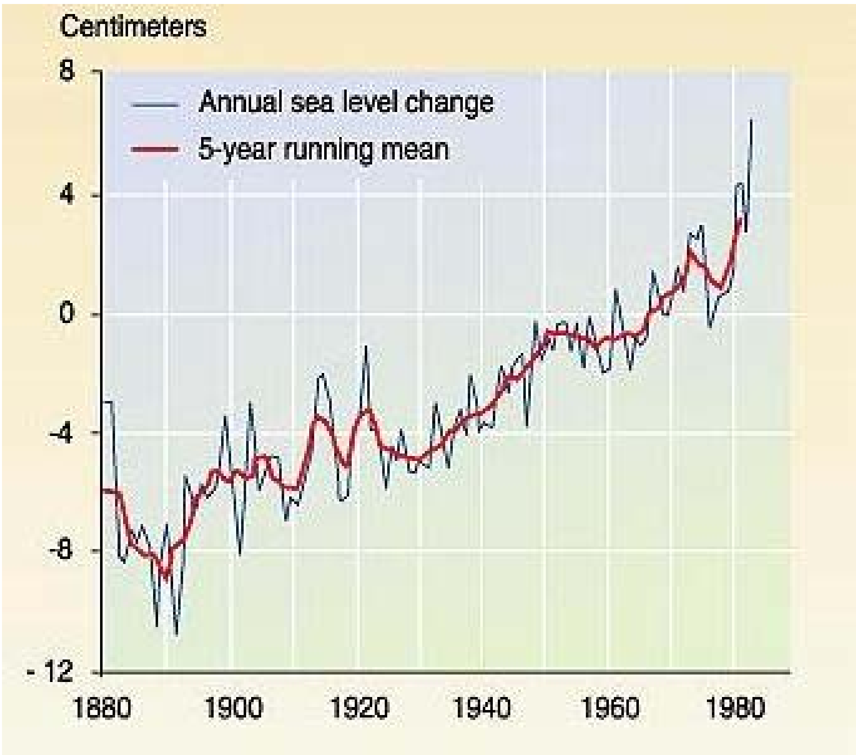


**Figure N-2: Historical Rise in Sea Level**

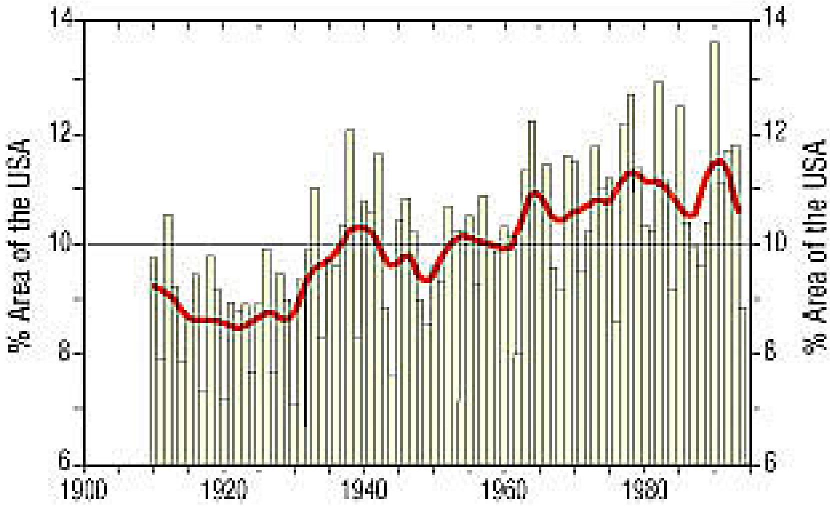

**Figure N-3: Percentage of US Area Experiencing more Extreme Rainfall**[2]

## Causes of Global Warming

It has been scientifically proven that greenhouse gases (water vapor, carbon dioxide, methane, nitrous oxide and the man-made CFC refrigerants) trap heat in the Earth's atmosphere and tend to warm the planet. A schematic illustrating this effect is shown in Figure N-4. The Inter-governmental Panel on Climate Change (IPCC) concluded that the apparent global warming in the last 50 years is likely the result of increases in greenhouse gases, which accurately reflects the current thinking of the scientific community. Scientists know for certain that human activities are changing the composition of Earth's atmosphere. Increasing levels of greenhouse gases, like carbon dioxide, in the atmosphere since pre-industrial times have been well documented. Figure N-5 illustrates both temperature and carbon dioxide concentration increases over the past thousand years. While the uncertainty in data prior to the development of sophisticated temperature measuring devices in the 19th century may be rather large, it is apparent from this graph that both temperature and carbon dioxide concentration have increased more rapidly over the past 100 years.

Though ninety-eight percent of total greenhouse gas emissions are *naturally* produced (mostly water vapor) and only 2 percent are from man-made sources, over the last few hundred years, the concentration of man-made greenhouse gases in the atmosphere has increased dramatically. Since the beginning of the industrial revolution, atmospheric concentrations of carbon dioxide have increased nearly 30 percent, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by about 15 percent. These increases have enhanced the heat-trapping capability of the earth's atmosphere and tend to remain in the atmosphere for periods ranging from decades to centuries. Figure N-6 shows the approximate makeup of greenhouse gases in our atmosphere today (excluding water vapor).

[2] Source: Center for Climate Change and Environmental Forecasting (www.climate.volpe.dot.gov/precip.html)

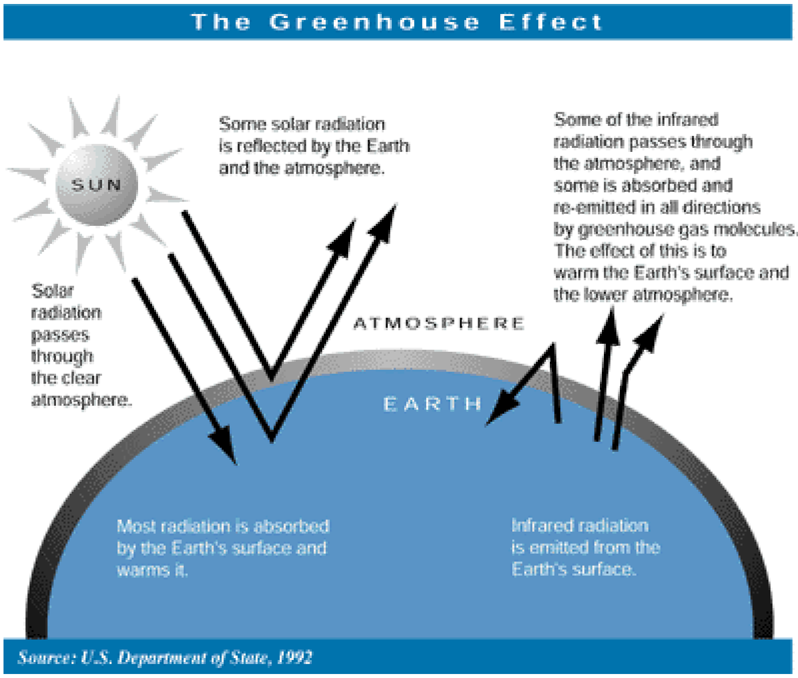


**Figure N-4: The Greenhouse Effect**[3]

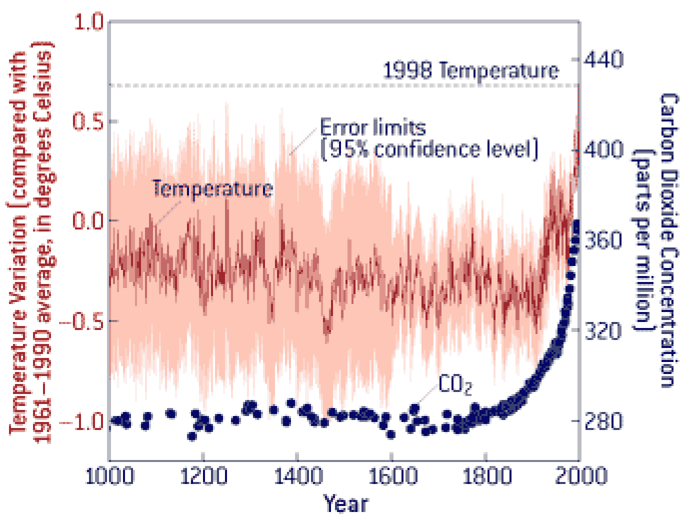


**Figure N-5: Temperature and Carbon Dioxide Concentration over the last Century**[4]

[3] Source: U.S. Department of State, 1992
[4] Source: Intergovernmental Panel on Climate Change

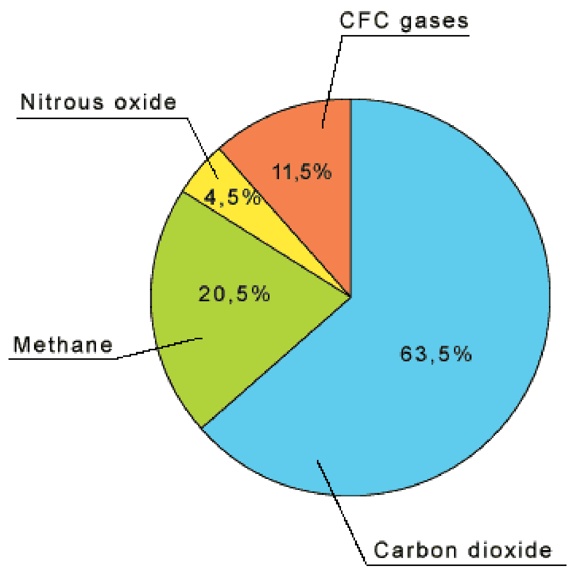


**Figure N-6: Greenhouse Gases Worldwide**[5]

Fossil fuels burned to run cars and trucks, heat homes and businesses, and power factories are responsible for about 98 percent of U.S. carbon dioxide emissions, 24 percent of methane emissions, and 18 percent of nitrous oxide emissions. Increased agriculture, deforestation, landfills, industrial production, and mining also contribute a significant share of emissions. In 1997, the United States emitted about one-fifth of total global greenhouse gases. Figure N-7 below provides a breakdown of the known sources of greenhouse gases. The largest contributors are electricity production and transportation, which both produce carbon dioxide. Together, they represent approximately one-third of the total man-made production of carbon dioxide. Industrial and commercial uses and residential heating make up about a quarter of the total. Figure N-8 illustrates the production of carbon dioxide by sector since 1970.

[5]Source: Institut Français du Pétrole (IFP) (http://www.ifp.fr/IFP/en/images/fb/gaz-effet-serre-fb04.gif)

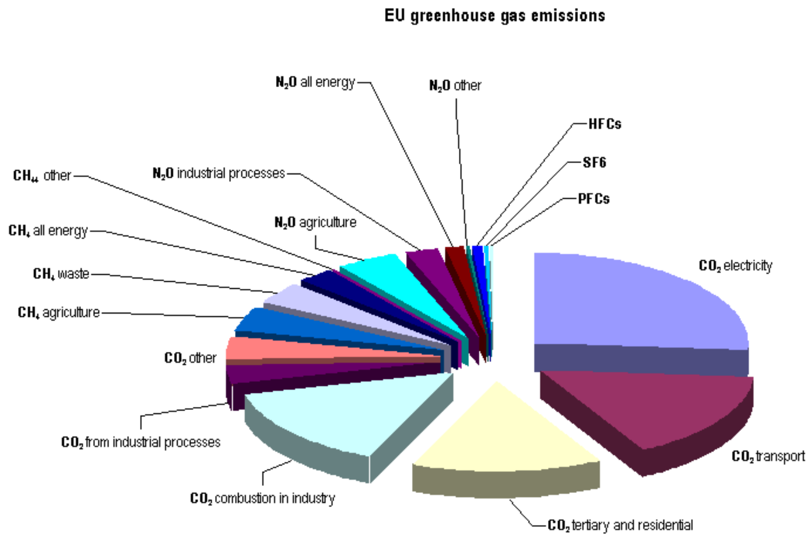


**Figure N-7: Sources of Greenhouse Gases[6]**

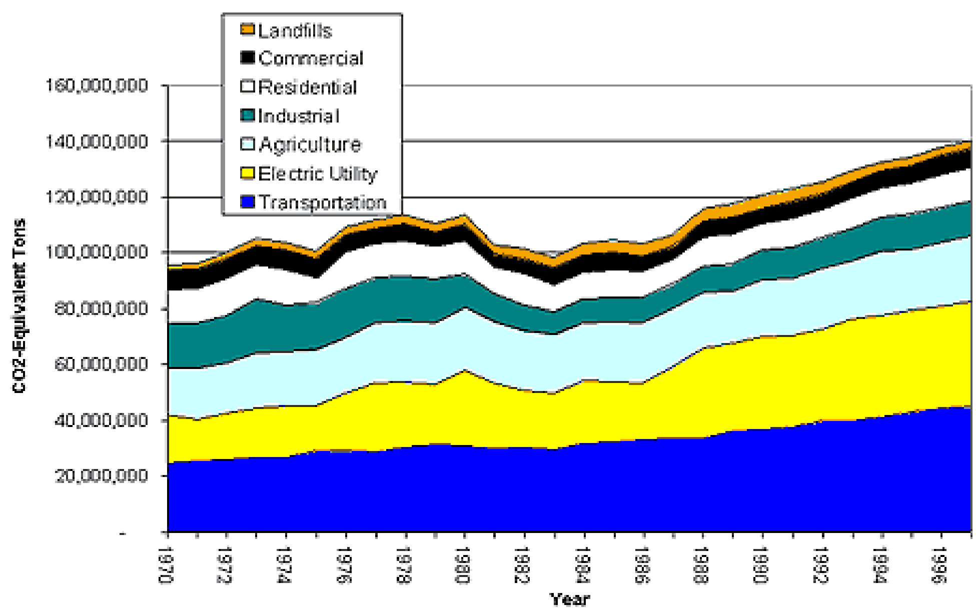


**Figure N-8: Sources of Carbon Dioxide Production[7]**

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[6] Source: Climate Action Network Europe (www.climnet.org)
[7] Source: Minnesota Pollution Control Agency (www.pca.state.mn.us)

Figuring out to what extent the human-induced accumulation of greenhouse gases since pre-industrial times is responsible for the global warming trend is still under debate. This is because other factors, both natural and human, affect our planet's temperature. Scientific understanding of these other factors – most notably natural climatic variations, changes in the sun's energy, and the cooling effects of pollutant aerosols – remains incomplete.

As atmospheric levels of greenhouse gases continue to rise, scientists estimate average global temperatures will continue to rise as a result. By how much and how fast remain uncertain. Based on assumptions that concentrations of greenhouse gases will continue to grow the IPCC projects further global warming of 2.2 to 10°F (1.4 to 5.8°C) by the year 2100. This range results from uncertainties in greenhouse gas emissions, the possible cooling effects of atmospheric particles such as sulfates, and the climate's response to changes in the atmosphere. The IPCC goes on to say that even the low end of this warming projection "would probably be greater than any seen in the last 10,000 years, but the actual annual-to-decadal changes would include considerable natural variability."

## Uncertainty Surrounding Climate Change

Scientists are more confident about their projections of climate change for large-scale areas (e.g., global temperature and precipitation change, average sea level rise) and less confident about the ones for small-scale areas (e.g., local temperature and precipitation changes, altered weather patterns, soil moisture changes). This is largely because computer models used to forecast global climate change are still ill equipped to simulate how things may change at smaller scales.

There are at least 19 different global models that simulate changes in temperature over time. Every one of these models, to some degree (no pun intended), projects a warming trend for the Earth. Each is a sophisticated computer model using modern mathematical techniques to simulate changes in temperature as a function of atmospheric and other conditions. Like all fields of scientific study, however, there are uncertainties associated with assessing the question of global warming and, as we are often reminded, a computer model is only as good as its input assumptions. The effects of weather (in particular precipitation) and ocean conditions are still not well known and are often inadequately represented in climate models -- although all play a major role in determining our climate.

Scientists who work on climate change models are quick to point out that they are far from perfect representations of reality, and are probably not advanced enough for direct use in policy implementation. Interestingly, as the computer climate models have become more sophisticated in recent years, the predicted increase in temperature has gotten smaller. Nonetheless, most climatologists concur that the warming trend is real and could have serious impacts worldwide.

## Potential Impacts of Global Warming

One of the consequences of global warming is a more rapid melting of ice caps, which would increase the likelihood of flooding at coastal cities. Given the forecasted range of global temperature increase, mean sea level is projected to rise by 0.09 to 0.88 meters by 2100, due to melting ice caps and thermal expansion of the oceans (due to higher water temperatures). Warmer oceans could also lead to shifts in upwelling and currents and could have detrimental impacts to ecosystems.

Evaporation should increase as the climate warms, which will increase average global precipitation. There is also the possibility that a warmer world could lead to more frequent and intense storms, including hurricanes. Preliminary evidence suggests that, once hurricanes do form, they will be stronger if the oceans are warmer due to global warming. However, it is unclear whether hurricanes and other storms will become more frequent. Figure N-9 shows the frequency of hurricanes since 1949. In spite of the decline in hurricanes in 1994 and 1995, it appears that a trend exists toward more frequent occurrences, but the data is not conclusive.

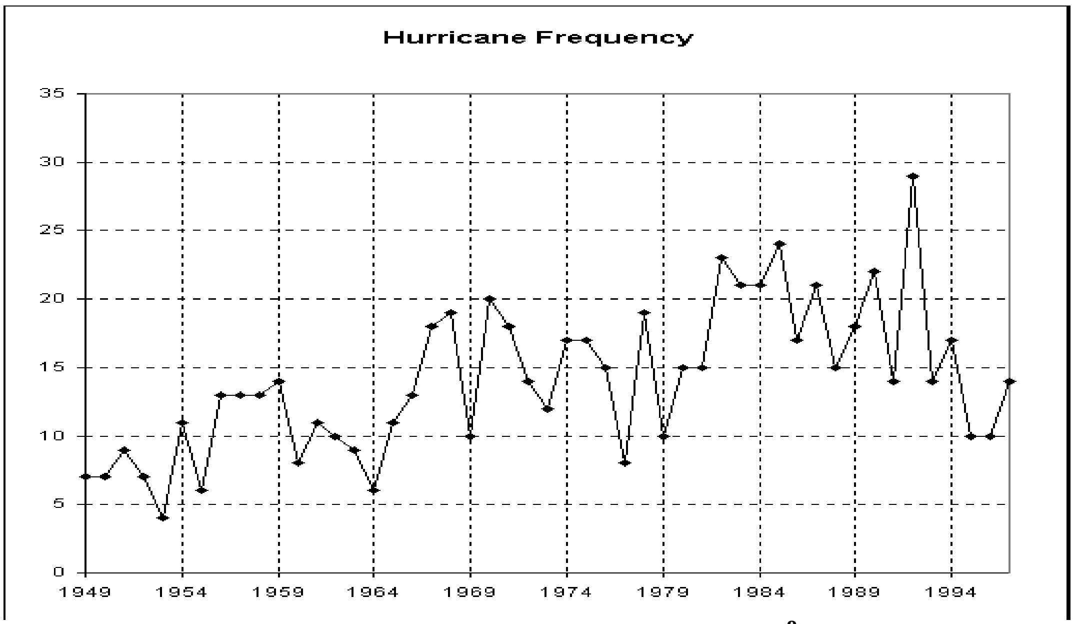


**Figure N-9: Frequency of Hurricanes**[8]

More and more attention is being aimed at the possible link between El Niño events – the periodic warming of the equatorial Pacific Ocean – and global warming. Scientists are concerned that the accumulation of greenhouse gases could inject enough heat into Pacific waters such that El Niño events would become more frequent and fierce. Here too, research has not advanced far enough to provide conclusive statements about how global warming will affect El Niño.

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

## Actions to Address Climate Change

Global warming poses real risks. The exact nature of these risks remains uncertain. Ultimately, this is why we have to use our best judgment – guided by the current state of science – to determine what the most appropriate response to global warming should be.

[8]Source: TV Weather (www.tvweather.com)

In 1992 the United States and nations from around the world met at the United Nations' Earth Summit in Rio de Janeiro and agreed to voluntarily reduce greenhouse gas emissions to 1990 levels by the year 2000. The Rio Treaty was not legally binding and, because reducing emissions would likely cause unwanted economic impacts, many nations were expected not to meet that goal.

Representatives from around the world met again in December of 1997 in Kyoto to sign a revised agreement. Because of concerns regarding the possible economic effects, the treaty excluded developing nations. However, the US Senate voted 95-0 against supporting a treaty that doesn't include developing nations. At the time, the Clinton Administration negotiators agreed to legally binding, internationally enforceable limits on the emission of greenhouse gases as a key tenet of the treaty. The president's position presupposed that the potential damage caused by global warming would greatly outweigh the damage caused to the economy by severely restricting energy use.

The Clinton Administration also supported a system of tradable permits to be used by companies that emit carbon dioxide. These permits could be bought and sold internationally, giving companies an incentive to lower emissions and thus sell their permits. But this system would require massive international oversight on the order of a worldwide Environmental Protection Agency (EPA) to track carbon dioxide emissions, and the costs to consumers would be high.

The U.S. did agree to a 7 percent reduction of carbon dioxide emissions from what they were in 1990 -- a target to be met by 2008-12. This agreement would place further restrictions on energy generation from fossil-fuel burning resources. There appears to be as much controversy regarding the economic impacts of control policies for greenhouse gases as there is regarding the effects of climate change. In addition, suggestions were made to establish a vigorous program of basic research to reduce uncertainties in future climate projections and to develop a system that monitors long-term climate predictions.

## ASSESSING IMPACTS TO THE NORTHWEST

### Northwest Climate Models

Dozens of groups around the world are actively investigating global climate change and its potential impacts.[9] Most of these organizations have developed complex computer models used to forecast long-term changes in the Earth's climate. These models are used to estimate the effect of greenhouse gases on the Earth's climate. The most sophisticated of these models are known as "general circulation models" or GCMs. These models take into account the interaction of the atmosphere, oceans and land surfaces.[10] Each of these models has been "calibrated" to some degree and crosschecked against other such models to give us more confidence in their forecasting ability.

The one problem that global models share, however, is that their minimum geographical scale is generally too large to make predictions for small regions such as the Northwest. GCMs tend to do a very reasonable job of forecasting on a global basis, but unfortunately, that information is of no use to planners in the Northwest. Thus, a method of "downscaling" the output from these

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

models has been developed.[11] This downscaled data matches better with hydrological data used to simulate the operation of the Columbia River Hydroelectric Power System. Thus, using temperature and precipitation changes forecast by global climate models, downscaled for the Northwest, an adjusted set of potential future water conditions and temperatures can be generated. The adjusted water conditions can be used as input for power system simulation models, which can determine impacts of climate change in the Northwest. Temperature changes lead to adjustments in electricity demand forecasts and river flow adjustments translate into both changes and temporal shifts in hydroelectric generation.

## Projected Changes in Northwest Climate and Hydrology

Downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean (JISAO)[12] Climate Impacts Group[13] at the University of Washington. This data was derived primarily from two GCMs, the Hadley Centre model (HC)[14] and the Max Planck Institute model (MPI)[15] although the Climate Impacts Group also uses other models.

The JISAO Climate Impacts Group at the University of Washington has compiled a set of projected future temperature and precipitation changes based on four global climate models.[16] Figure N-10 below illustrates those projections for the four models and also shows the mean (dark line). Two conclusions can be drawn from the figure below; 1) that each model shows a net temperature and precipitation increase, and 2) that there is great variation in both the temperature and precipitation forecasts.

For the Council's analysis, mean monthly temperature changes were used for both 2020 and 2040. Figure N-11 illustrates the temperature change forecast used for 2020 and 2040. Please note that in Figure N-11, the vertical temperature scale is in degrees Fahrenheit instead of Celsius and the horizontal time scale reflects an operating year (September through August) as opposed to a calendar year. Because the correlation between temperature change and water condition was not yet available, the analysis assumed that mean monthly temperature changes would apply to each water condition examined.

[11] Wood, A.W., Leung, L. R., Sridhar, V., Lettenmaier, Dennis P., no date: "Hydrologic implications of dynamical and statistical approaches to downscaling climate model surface temperature and precipitation fields."
[12] http://tao.atmos.washington.edu/main.html
[13] http://tao.atmos.washington.edu/PNWimpacts/index.html
[14] http://www.met-office.gov.uk/research/hadleycentre/models/modeltypes.html
[15] http://www.mpimet.mpg.de/en/web/
[16] The global climate models used for these scenarios were the HadCM2, HadCM3, ECHAM4, and PCM3. Mote, P., 2001: "Scientific Assessment of Climate Change: Global and Regional Scales," White Paper, JISAO Climate Impacts Group, University of Washington.

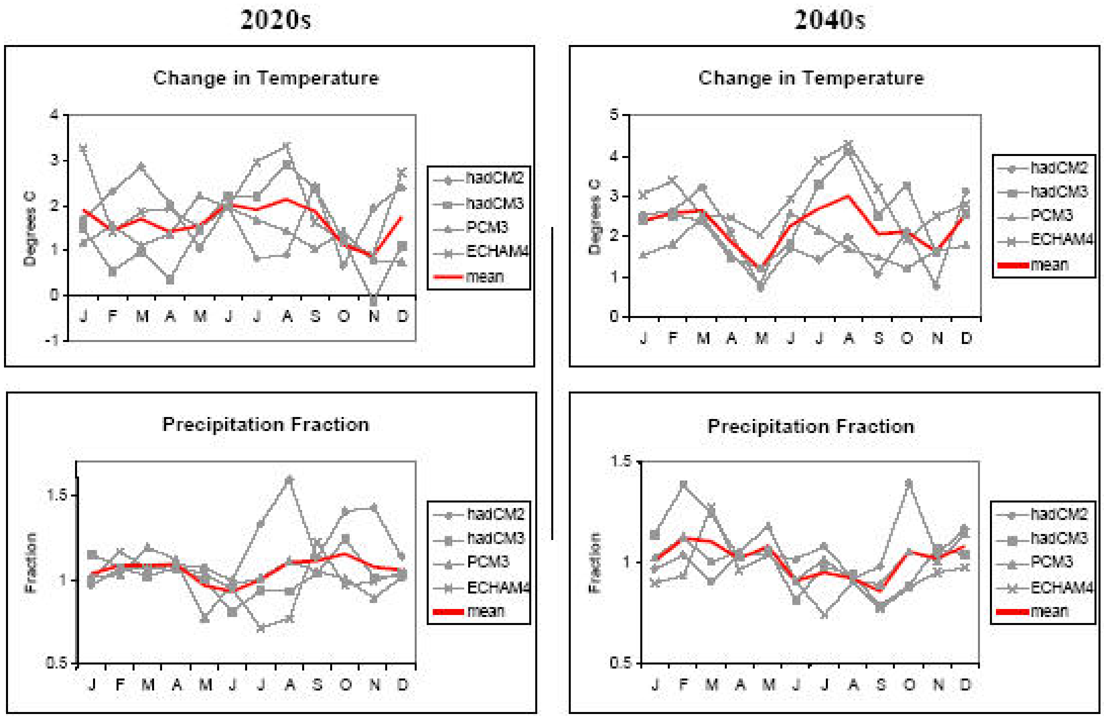


**Figure N-10: Temperature and Precipitation Change Forecasts**[17]

[17] Borrowed from CIG Publication No. 145, Hamlet, Alan, F., July 3, 2001: "Effects of Climate Change on Water Resources in the Pacific Northwest: Impacts and Policy Implications," JISAO Climate Impacts Group, University of Washington.

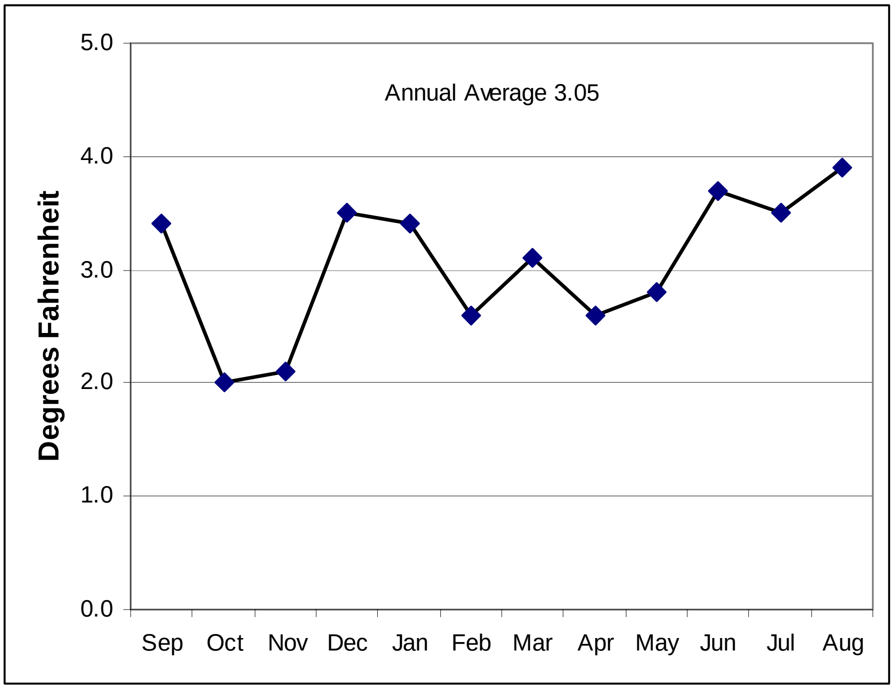


**Figure N-11: Forecast Change in NW Monthly Temperatures by 2020**

**Table N-1: Forecast Temperature Increases for the Northwest (Degrees Fahrenheit)**

| | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2020** | 3.4 | 2.0 | 2.1 | 3.5 | 3.4 | 2.6 | 3.1 | 2.6 | 2.8 | 3.7 | 3.5 | 3.9 |
| **2040** | 3.7 | 3.8 | 2.9 | 4.6 | 4.3 | 4.7 | 4.8 | 3.4 | 2.2 | 4.1 | 4.9 | 5.4 |

The Hadley Centre (HC) model generally shows an overall increase in precipitation across the year. The Max Planck Institute (MPI) model tends to forecast a drier future. Figures N-12a and N-12b compare the mean annual runoff volumes (in millions of acre-feet as measured at The Dalles Dam) for each scenario for 2020 and 2040. The historical mean is about 133 million acre-feet (maf). For this analysis, the historic water conditions from 1930-78 were used.

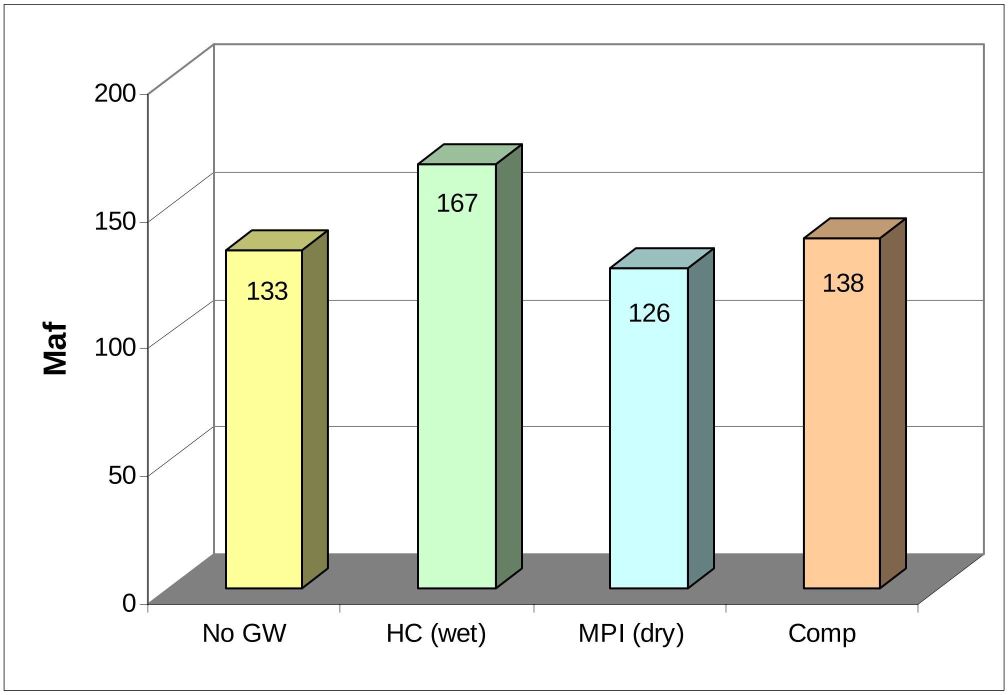


**Figure N-12a: Annual Average Runoff Volume at The Dalles (2020)**

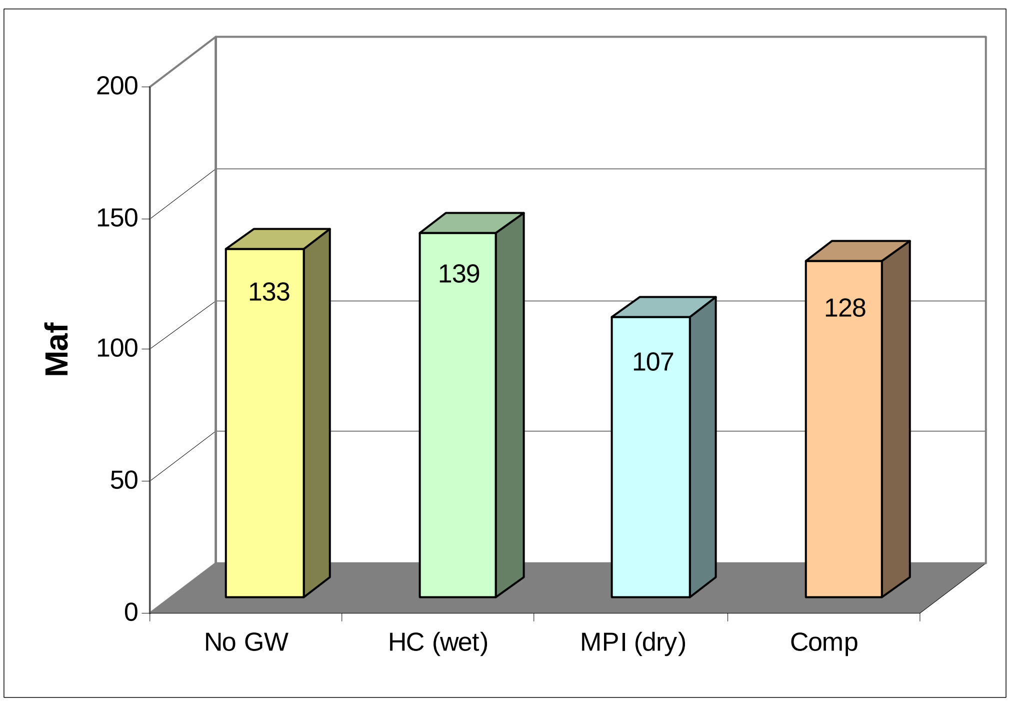


**Figure N-12b: Annual Average Runoff Volume at The Dalles (2040)**

For 2020, the HC model shows a greater annual runoff volume (167 Maf compared to the historical average of 133 Maf). Total useable storage in the Columbia River Basin is about 42 maf, with about half of that available in U.S. reservoirs. Under the HC scenario, the hydroelectric system should see about 34 Maf more water on an average annual basis. That is almost as much water as can be stored in all of the reservoirs on the Columbia River. This means that the region can displace more non-hydroelectric resources and sell more surplus hydroelectric energy in the wholesale market. Overall, it means that the region should see a decrease in the average cost of energy production.

The MPI model shows a slight annual decrease in river volume (126 Maf relative to the historical average of 133 Maf). While this reduction in average annual volume is not as large as the projected increase in volume under the HC model, it is still a significant amount of water. The 7 Maf reduction amounts to about a 5 percent drop in river volume, which translates into higher costs for the region because more expensive non-hydro resources must be run to make up the difference (or less revenue will be gained from the sale of surplus hydroelectric generation). More on the estimated cost under each of theses scenarios is discussed later.

For 2040, the HC model forecasts a much smaller increase in annual runoff volume (139 Maf as opposed to 167 Maf for 2020). Although smaller, the projected average annual river volume for 2040 is still 6 Maf larger than the historical average and should still result in lower overall average operating costs for the northwest power system. The MPI model for 2040 shows a much greater decrease in annual volume (107 Maf). This decrease of 26 Maf, relative to the historical annual average of 133 Maf, is more water than can be stored in U.S. reservoirs (21 Maf) and would increase the cost of operation.

Despite the inconsistencies between the HC and MPI models in terms of projected annual river volume, they both show greater winter period runoff (and consequently flows) and lower summer runoff. More information on this will be discussed in the next section.

## Assessment of Impacts to the Power System

Three sets of hydrological data were produced for operating years[18] 2020 and 2040. Each is a downscaled and bias-adjusted set of water conditions generated using output from a particular global model. The first two sets of water conditions are derived from the HC and MPI models and the third set is derived from a combination of model runs (COMP). Other caveats regarding this study are specified below:

- Adjusted streamflows are only available for 1930-78 water conditions (out of the 1929-78 historical record generally used for Northwest power-system analysis)
- Only one monthly temperature adjustment is associated with each water condition (this implies no correlation between water conditions and temperature change)
- Operating guidelines (rule curves) for the hydro system have not been adjusted (i.e. flood control has not been adjusted for the change in spring runoff forecast nor have firm drafting limits been re-optimized)
- Summer demand sensitivity to temperature is likely too low (it must be increased to take into account the higher level of air-conditioning penetration)

[18] Power planners in the Northwest generally define an operating year to be from September through August.

- This analysis is a deterministic study, in the sense that each adjusted water condition was given an equal likelihood of occurring.
- The analysis modeled the current generating-resource/demand mix (no attempts were made to use projected resources or loads in 2020 or 2040)

## Impacts to River Flows

Most global climate models indicate that the Northwest will become hotter across each month of the year. If this is true, then less precipitation will fall as snow in fall and winter months, thus reducing the amount of snowpack in the mountains. Also, more rain in winter months (as opposed to snow) means higher streamflows at a time when electricity demand is highest. This, plus the fact that demand for electricity is likely to decrease due to warmer winter months, should ease the pressure on the hydroelectric system to meet winter electricity needs. In fact, excess water (water than cannot be stored) may be used to generate electricity that will displace higher-cost thermal resources or be sold to out-of-region buyers.

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

However, any winter power benefits could be offset by summer problems. With a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows. As mentioned earlier, lower river flows (and less hydroelectric generation) may not be a Northwest problem now because of the excess hydroelectric system capacity. Except for some small portions of the northwest, the region experiences its highest demand for electricity during winter months. However, as summer temperatures increase so will electricity demand due to anticipated increases in air-conditioning use. In addition, potentially growing constraints placed on the hydroelectric system for fish and wildlife benefits may further reduce summer peaking capability. It is also possible that summer air-quality constraints may be placed on northwest fossil-fuel burning resources (there are none currently), which would also decrease the peaking capability. The projected increase in Northwest summer demand along with potential reductions in both hydroelectric and thermal generation may force the Northwest to compete with the Southwest for resources. Currently, the Northwest has surplus capacity during summer months when the Southwest sees its peak demand and the Southwest is surplus in the winter months when the Northwest has its peak.

This unfortunately, is not the only summer problem inherent with a climate change. Because river flows are likely to decrease, smolt (juvenile salmon) outmigration (journey to the ocean) and adult salmon returns will be affected. Lower river flows translate into lower river velocity and longer travel times to the ocean for migrating smolts. Lower river flows also mean that water temperature may increase, another factor contributing to smolt mortality. In a later section, some actions will be explored that may ease this situation, although in the worst case the region will have insufficient means to adjust to the forecasted changes.

Figures N-13a, N-13b and N-13c illustrate monthly average river flows at The Dalles for the historic water record and the climate-change adjusted water record (all based on historic natural flows from 1930 to 1978). Figure N-13a shows the HC model adjustments for both 2020 and 2040. The HC data reflects a warm-and-wet scenario, which translates into higher flows, especially in winter and early spring. Flows are lower in summer through early fall. As with all the climate model runs, flows in 2040 are projected to be lower than in 2020. In addition to the overall increase in river flow volume, the peak flow occurs a little earlier than the historic average. Peak flows in the HC adjusted data occur in mid-May as opposed to early June for the historic data. This same pattern exists for each of the three climate change scenarios examined.

Figure N-13b illustrates projected changes in average river flows for the MPI scenario (warm and dry). In this case, winter flows are higher but not nearly as much as in the HC case. Late spring and summer flows are greatly reduced. Again we see the slightly earlier peak in about mid-May. Figure N-13c shows average river flows for the COMP scenario, which is essentially an average of several climate change studies.

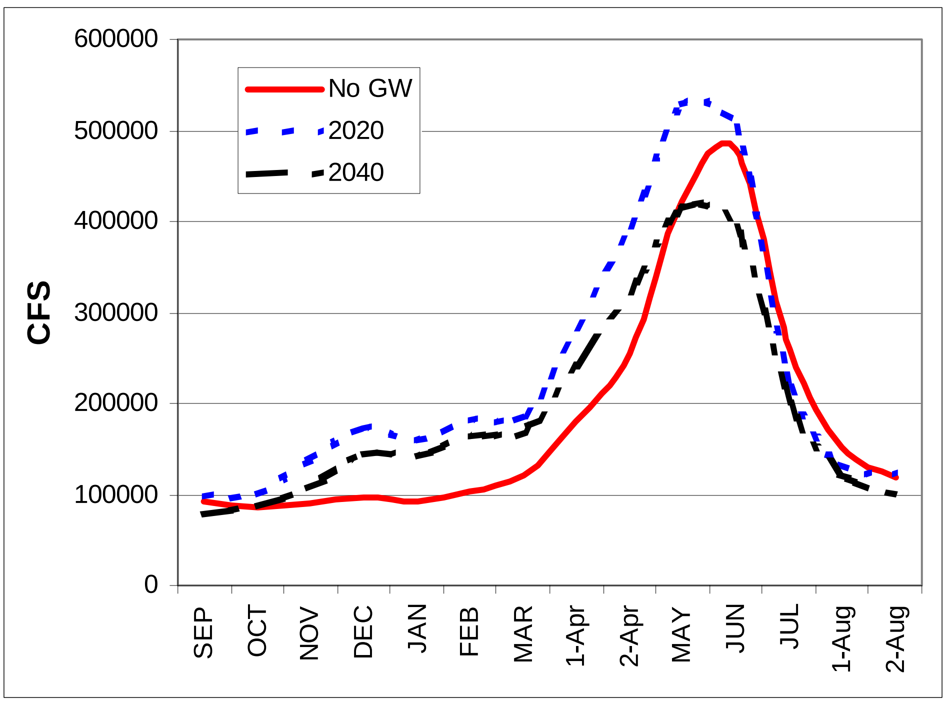


**Figure N-13a: Average Unregulated Flow at The Dalles - HC (wet)**

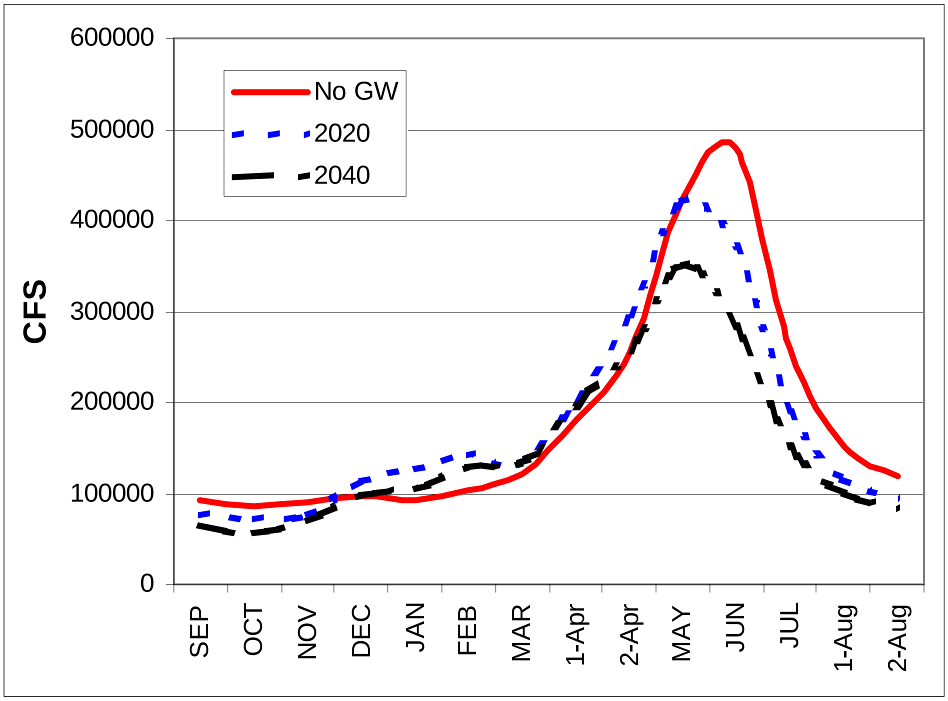


**Figure N-13b: Average Unregulated Flow at The Dalles - MPI (dry)**

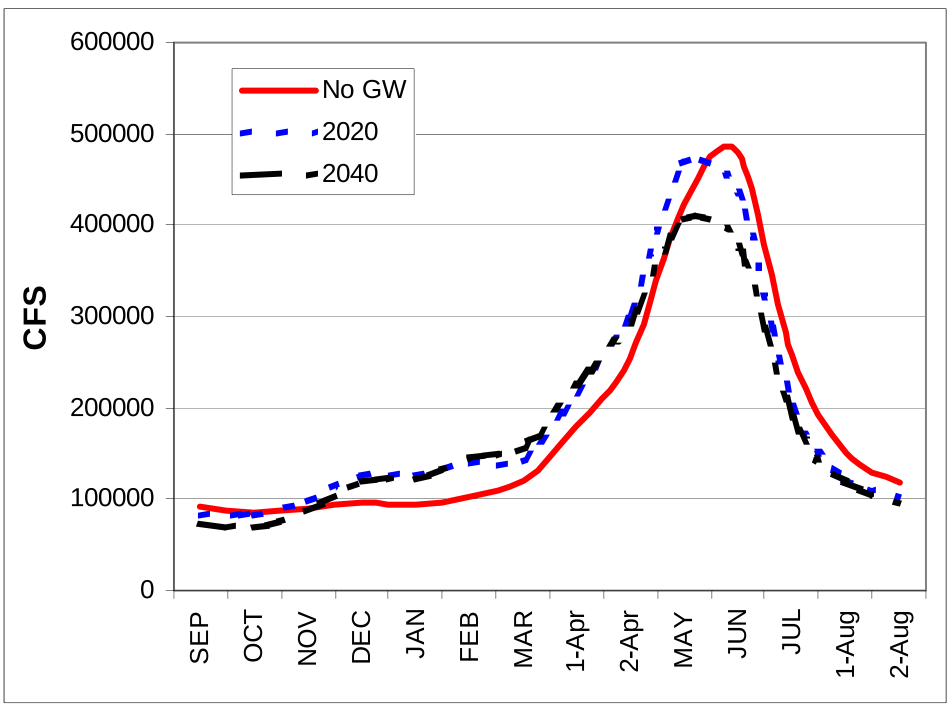


**Figure N-13c: Average Unregulated Flow at The Dalles - COMP**

## Effects on Electricity Demand

There is a clear relationship between temperature and electricity demand. For electrically heated homes, as the temperature drops in winter months, electricity use goes up. Even for non-electrically heated homes, electricity use in winter tends to increase due to shorter daylight hours. Based on data from the Northwest Power Pool, for each degree Fahrenheit the temperature drops from normal, electricity demand increases by about 300 megawatts. This value has stayed fairly consistent over the past several years, in spite of the fact that a smaller percent of new homes are being built with electric heat. If this relationship holds true, then a five-degree increase in average temperature over winter months translates into about a 1500-megawatt decrease in electricity demand.

However, the Council does not rely on the Power Pool to estimate fluctuation in demand caused by temperature changes. Simulation models used by the Council use the HELM algorithm to assess demand variations as a function of temperature. Results of that relationship are presented in Figure N-14, which plots the average monthly temperature increase for 2040 and the corresponding change in electricity demand. For December, the average increase in temperature is about 5 degrees and the corresponding decrease in demand is nearly 2,000 megawatts. This is a little more than the Power Pool's anecdotal relationship would predict but the Power Pool's relationship is based more on hourly demand than monthly average demand.

In the summer, higher temperatures mean greater electricity demand because of greater air conditioning use. While the HELM model forecasts for winter demand decreases seem reasonable, at least on the surface, forecasts for summer demand increases are likely too low. Since the data for HELM was developed, air-conditioning penetration rates have increase significantly. In other words, a greater percentage of new homes are being built with air conditioning and more room-sized air conditioners are being used. Thus, forecasted increases in demand (per degree increase in temperature) for summer months (Figure N-14) are too low and must be revised.

However, power planners have rarely had to concern themselves with summer problems because the Northwest has historically not been a summer peaking region and because of the great capacity of the hydroelectric system. The existing power system is sufficient to "pick up" the additional demand that is projected for future summer months. However, with continued demand growth, increasing operating constraints on generating resources and perhaps little incentive to build, it is possible that at some future date the Northwest will be forced to plan for both a winter and summer peak. According to the Northwest Power Pool, the difference between winter peak load maximums and summer peak loads is getting smaller each year.

However, even if our analysis included higher summer demands, the operation of the hydroelectric system over those months would not likely change because of the rather rigid constraints for fish and wildlife protection. Without modifications to those constraints the decrease in forecasted natural summer flows (shown in Figure N-13) are not likely to be augmented by release of stored water in reservoirs. Under this assumption, higher summer demands would result in an increased cost to the region, either from reduced sales of surplus hydroelectric energy or from purchases from an expensive wholesale market.

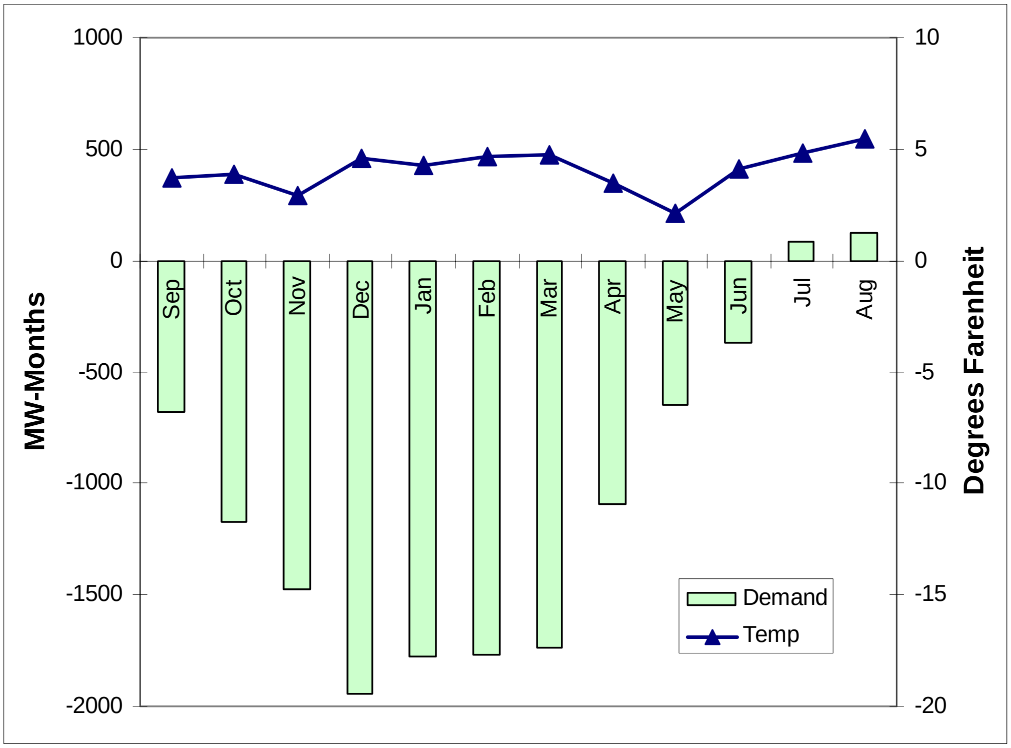


**Figure N-14: Average GW Impacts to Temperature and Demand (2040)**

## Methodology Used to Assess Impacts to the Power System

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

The GENESYS[19] computer model is a Monte Carlo program that simulates the operation of the northwest power system. It performs an economic dispatch of resources to serve regional demand. It assumes that surplus northwest energy may be sold out-of-region, if electricity prices are favorable. And, conversely, it will import out-of-region energy to maintain service to firm demands.

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

The important stochastic variables are hydro conditions, temperatures (as they affect electricity loads) and forced outages on thermal generating units. The model typically runs hundreds of simulations for one or more calendar years. For each simulation it samples hydro conditions,

[19] See www.nwcouncil.org/GENESYS

temperatures and the outage state of thermal generating units according to their probability of occurrence in the historic record.

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

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

## Changes to Hydroelectric Generation

Table N-2 summarizes the economic results of the Council's study. The average annual change in hydroelectric generation is provided for each climate change scenario for both 2020 and 2040. What is clear from this table is that runoff volume (fuel for the hydroelectric system) makes a big difference in total annual generation. Under the MPI scenario (warm and dry), the hydroelectric system is estimated to lose about 700 average megawatts of energy in 2020 and 2,000 average megawatts by 2040. Current annual hydroelectric generation for the Columbia River system is about 16,000 average megawatts under average conditions and about 11,600 average megawatts for the driest year.[20] These energy losses are not cheap. The estimated regional annual cost of the MPI scenario is $231 million in 2020 and $730 million by 2040.

For a warm-and-wet scenario, the economic outlook is much better. With more fuel for the hydroelectric system, the region is forecast to see about 2,000 average megawatts more energy by 2020 and about 300 average megawatts more by 2040. The corresponding economic benefits are presented in Table 2 below. Under the combination scenario, the region will see a slight increase in generation by 2020 and a net loss of generation by 2040. This scenario shows a net increase in generation (and revenue) by 2020 but a net loss of generation and revenue by 2040.

[20] For another perspective, hydroelectric energy losses due to measures provided for fish and wildlife concerns amount to about 1,100 average megawatts.

**Table N-2: Summary of Energy and Cost Impacts**

| | Change in Annual Energy (average megawatts) | | Annual Benefits (Millions) | |
|---|---|---|---|---|
| | **2020** | **2040** | **2020** | **2040** |
| **HC (wet)** | 1982 | 333 | 777 | 169 |
| **COMP** | 164 | -477 | 74 | -155 |
| **MPI (dry)** | -664 | -2033 | -231 | -730 |

Figure N-15 below illustrates the average monthly change in hydroelectric generation for each of the climate change scenarios. In each case, generation increases over the winter and early spring months and decreases in the late spring and summer months. The magnitude of the change depends on the specific scenario but for all climate-change scenarios examined, the direction of the change is the same.

Figures N-16 and N-17 illustrate the change in regulated outflows and cost. As expected, the same pattern of change observed in Figure N-15 for generation (higher values in winter and lower values in summer) exists for river flows and cost. Figure N-18 provides the average monthly electricity prices used to calculate economic costs/benefits.

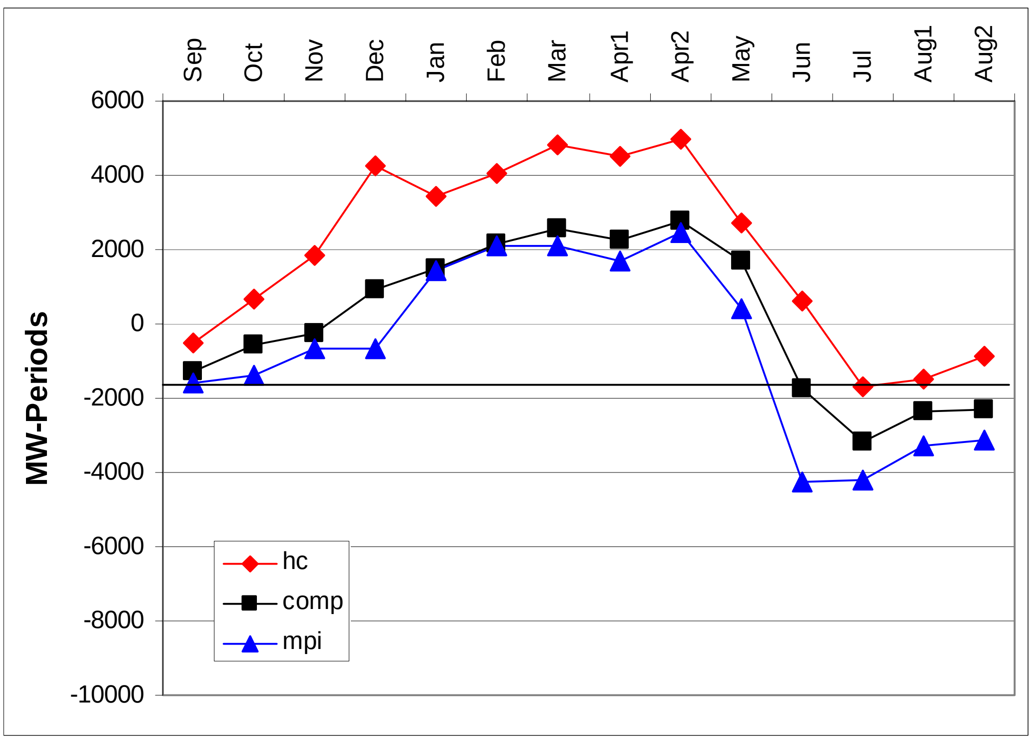


**Figure N-15: Average Difference in Hydro Generation (2020)**

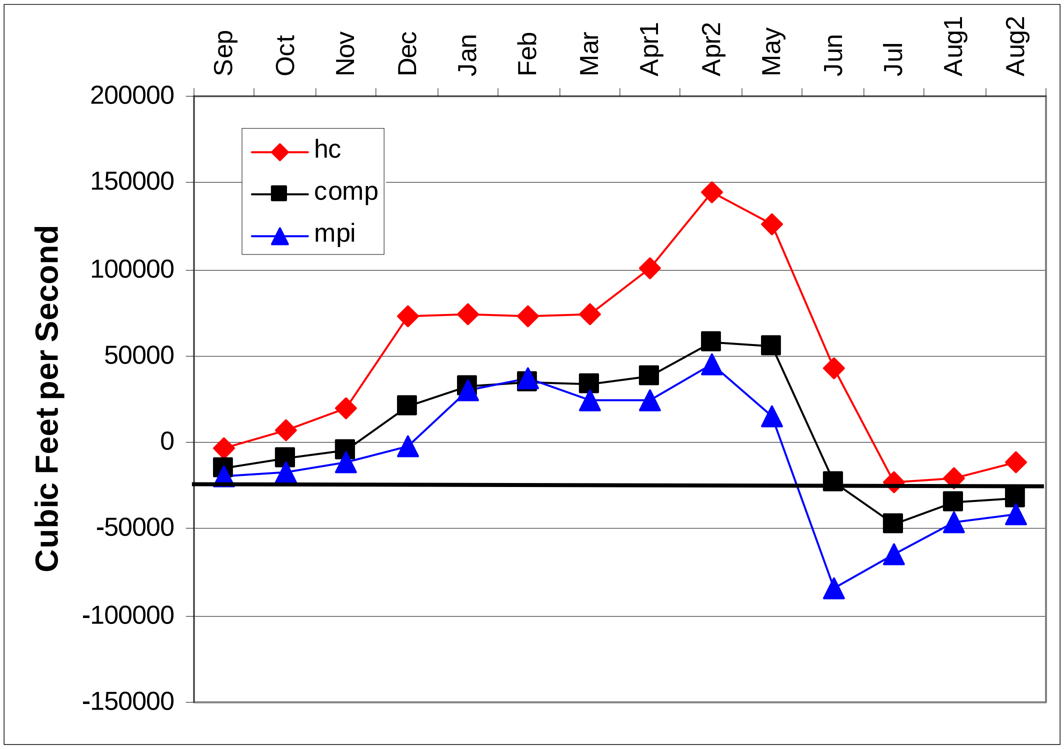


**Figure N-16: Average Difference in Regulated Flows at The Dalles (2020)**

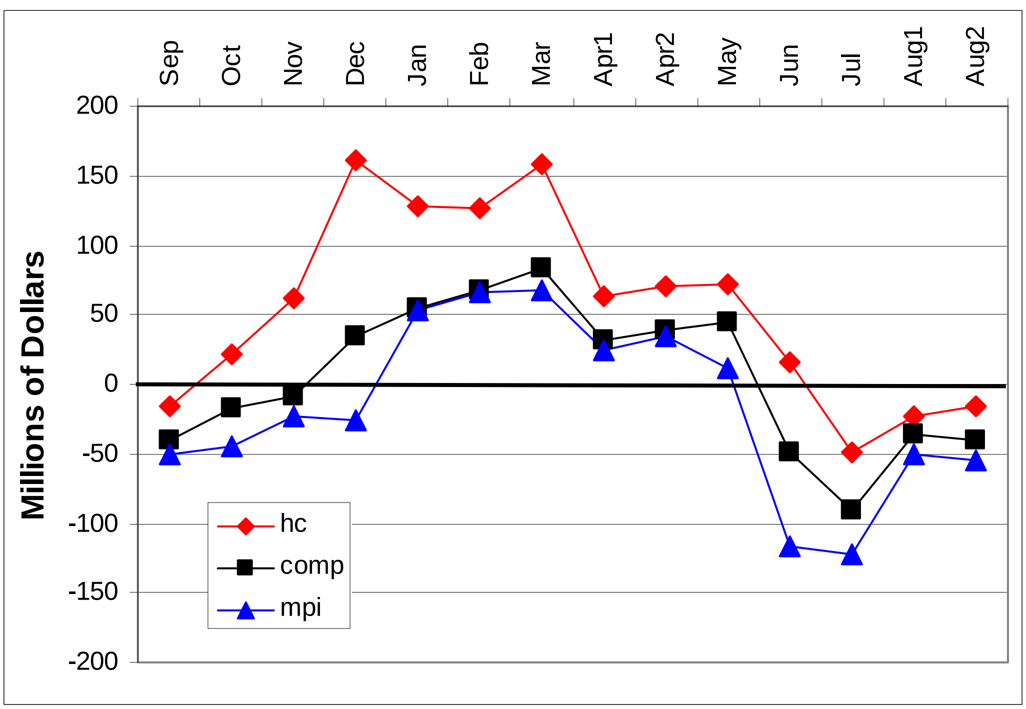


**Figure N-17: Average Regional Benefits (2020)**

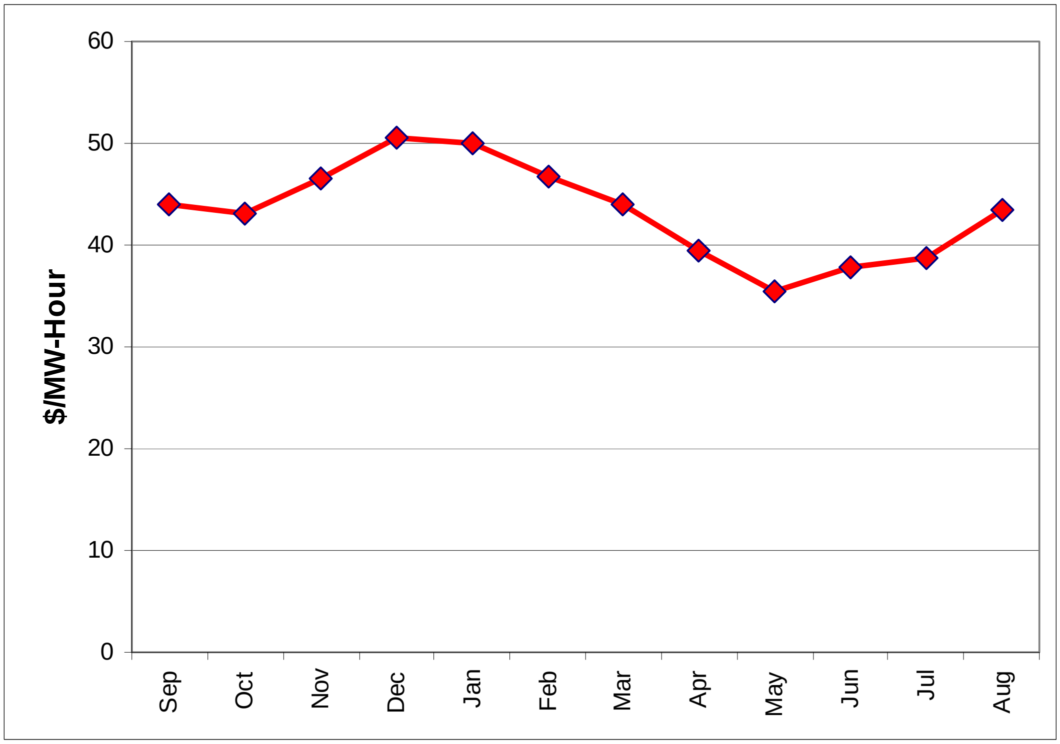


**Figure N-18: Forecast Bulk Electricity Prices**
**(at Mid-Columbia, 2006 operating year, 2004 dollars)**

Figures N-19 and N-20 illustrate the data in Table N-2 in graphic form. Conclusions drawn from this study are that; 1) the expected annual change in hydroelectric generation due to climate change depends heavily on forecasted changes to future precipitation (a very uncertain factor) and 2) power-system benefits or costs of climate change correspond directly with the change in runoff volume.

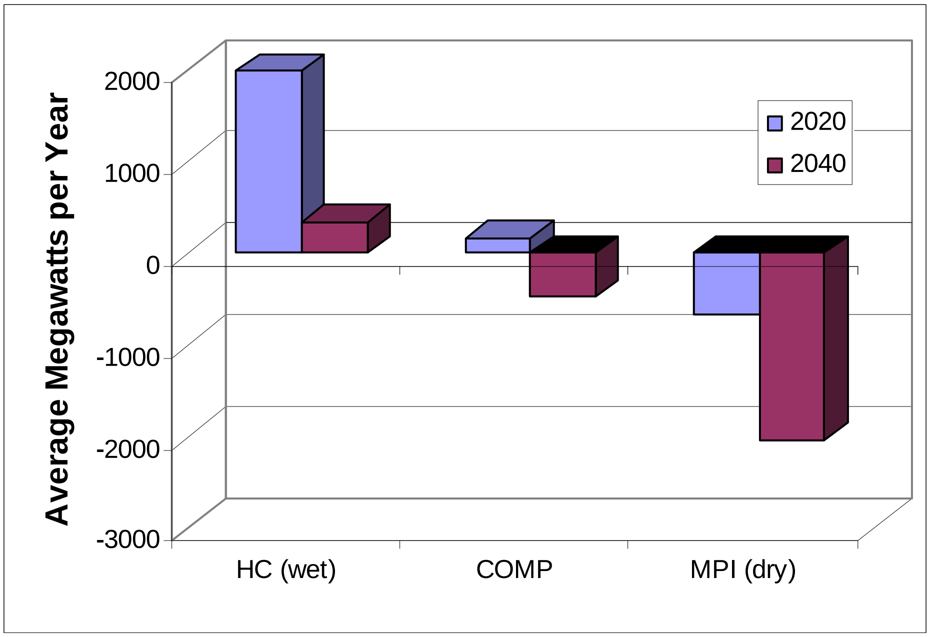


**Figure N-19: Average Annual Change in Hydro Generation**

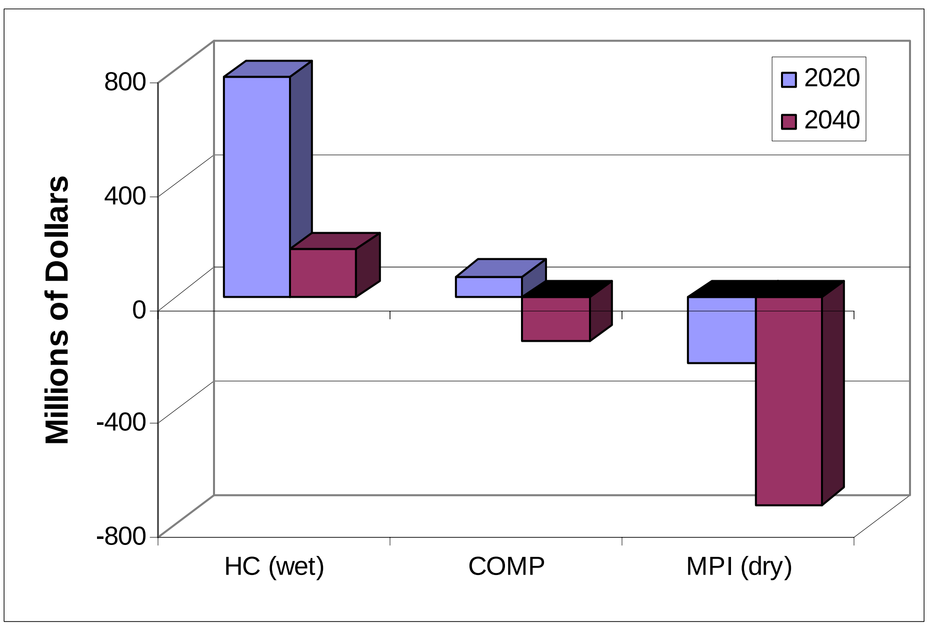


**Figure N-20: Average Annual Regional Benefits**

## Other Impacts

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

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

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

## Improving the Analysis

There are several areas where we can improve this analysis. First of all, a larger set of water conditions (1929-1999) should be used. Secondly, a correlated set of monthly temperatures and electricity prices will be used for each water condition. Summer demand response to temperature changes will be revised to incorporate the latest data on air-conditioning penetration rates. In addition, the anti-bias river-flow adjustments are being refined, as are some other data from the Climate Impacts Group.

However, while the final results will change somewhat in magnitude when the revisions mentioned above are incorporated, the general conclusions should not. We can expect, for example, that summer flows will decrease regardless of the climate-change scenario. Only the magnitude of the decrease is still in question. Also, there is no doubt that hydroelectric generation will be shifted across the months of the year. Whether this benefits the region economically or not depends on the overall increase or decrease in river volume.

# POTENTIAL MITIGATING ACTIONS FOR THE NORTHWEST

The development of this power plan for the Northwest incorporates actions intended to addresses future uncertainties and their risks to service and to the economy. Such uncertainties include large fluctuations in electricity demand, fuel prices, changes in technology and increasing environmental constraints. Though the effects of climate change remain imperfectly understood, it would be unwise for the Council to ignore its potential impacts to the region.  Strategies should be developed to 1) help suppress warming trends and, 2) to mitigate any potential impacts.

In terms of suppressing warming trends, the region should place additional emphasis on reducing the net carbon dioxide production of the power system.  Any incentive to reduce greenhouse gases should be examined and electricity customers should be encouraged to use their energy more efficiently.  Other actions that would help include;

- Developing low carbon energy sources,
- Substituting more efficient lower-carbon producing energy technologies for older, less efficient technologies, and
- Offsetting unavoidable carbon dioxide production with sequestration technologies.

## Reservoir Operations

While no immediate actions regarding reservoir operations are indicated by the analysis, the scoping process should begin to identify potentially mitigating operations to offset climate change impacts. Some of those actions may include:

- Adjust reservoir operating rule curves to assure that reservoirs are full by the end of June
- Allow reservoirs to draft below the biological opinion limits in summer months
- Negotiate to use more Canadian water in summer
- Use increased winter streamflows to refill reservoirs (US and Canadian)
- Explore the development of non-hydro resources to replace winter hydro generation and to satisfy higher summer needs.

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# The Interaction between Power Planning and Fish and Wildlife Program Development

## BACKGROUND

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

As the years of 2000 and 2001 unfolded, analyses by the Council and others indicated that fully implementing the NOAA Fisheries' 2000 Biological Opinion (BiOp) mainstem hydroelectric operations in 2001 was very likely to compromise power system reliability. This was due to very dry conditions in that year and the basic state of power supply in the Northwest and the rest of the Western Interconnection. Allowances in the BiOp, however, permit the curtailment of fish and wildlife operations during emergencies. The Bonneville Power Administration (Bonneville) declared a power emergency in that year based on the water supply and the lack of available generation on the market. Decisions were made to severely reduce fish bypass spill during the spring and summer months in order to ensure adequate supplies of power and to manage the economic impact of the high market prices. [2]

The events of 2001 are just one example that there will always be significant financial incentives to deviate from prescribed fish and wildlife operations when power supplies become tight and prices soar. The solution is to develop a power plan that assures the region an adequate power supply and also minimizes the risk of emergency interruptions to fish and wildlife operations.

## THE COUNCIL'S ROLE

The Council has dual responsibilities: to "protect, mitigate and enhance" fish and wildlife populations while assuring the region "an adequate, efficient, economical and reliable" power supply.[3] The interpretation of this mandate has led to great debate within the region. Some argue that fish and wildlife needs must be balanced or integrated with power planning activities. This implies that some sort of cost-effectiveness analysis be done, examining the tradeoff between biological benefits and power system costs. Others argue, however, that fish and wildlife operations should be viewed as firm environmental constraints similar to air and water quality standards. This implies that the power system would build adequate supplies to ensure that fish operations would never be compromised, regardless of cost. These two positions bracket the range of opinions regarding these often conflicting operations.

[1] "Optimizing" here means that energy production is maximized limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.
[2] See the Council's account of the events of 2000-01 in the main power plan document.
[3] See the Council's publication "Analysis of Adequacy, Efficiency, Economy and Reliability of the Power System"

Although developed at different times and under different processes, the Council has attempted to use an integrated approach in developing both its fish and wildlife program (program) and the power plan (plan). During the development of the program, physical and economic impacts of each fish and wildlife measure affecting the operation of the hydroelectric system were assessed and considered before final adoption of the program. The Council, in its program, has recommended that fish measures be examined for their cost-effectiveness. The program dictates that if the same biological objectives can be met at less cost, those less costly means should be pursued.

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

## RECOMMENDATIONS

Federal agencies have formed several committees through the biological opinion process to deal with in-season operational issues affecting fish and power. The Technical Management Team (TMT) consists of technical staff from both federal and non-federal agencies that usually meet on a weekly basis to assess the operation of the hydroelectric system. Requests for variations to those operations can be made and discussed at TMT meetings. Conflicts that cannot be resolved at the technical meetings are passed on to the Implementation Team (IT), which consists of higher policy-level staff. Impasses not resolved by this group are forwarded to the Executive Committee (EC), made up of executive staff from the various participating organizations. The process of resolving conflicts in proposed hydroelectric operations can sometimes be lengthy and cumbersome.

While the existing committee structure is intended to solve in-season problems, no currently active process exists to address long-term planning issues. The Council recommended in its 2003 program that both in-season and annual decision-making forums be improved.[4] The program states "at present, this decision structure is insufficient to integrate fish and power considerations in a timely, objective and effective way." It goes on to recommend that the forums should broaden their focus by including "expertise in both biological and power system issues" and by directly addressing longer-term planning concerns, not just weekly and in-season issues.

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

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

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

## ACTION ITEM

In this power plan, the Council recommends (Action F&W-1 in the Action Plan) that it "will work with federal agencies, the states, tribes, and others to broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning." This action is intended to improve the interaction between power planning efforts and fish and wildlife program development. More specifically this may include the following:

### NOAA Fisheries and other Federal Agencies

- Improve and broaden the focus of forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning.
- Allow region-wide participation in these forums.

### Council, Bonneville Power Administration and Hydroelectric Facility Operators

- Analyze the physical impacts (river flows and reservoir elevations) and economic impacts (changes in energy production and cost) of alternative mainstem operations for fish and wildlife.
- Whenever appropriate, analyze physical and economic analysis of individual components or sets of components of a fish and wildlife operation.

### Council

- Work with the Independent Economic Advisory Board (IEAB) to continue to develop and demonstrate methods to improve the cost effectiveness of the fish and wildlife operations.
- Work with fish and wildlife managers to develop a methodology to assess whether protective mainstem measures are being treated equitably. This may involve establishing some sort of a metric similar to those developed to assess power system reliability.

### Fish Managers

- Work with power planners and agencies to develop a minimum impact curtailment plan for fish and wildlife operations in the event of a power emergency.
- Work with power planners to assure the region that the most cost-effective measures are taken to achieve biological objectives.

## BENEFITS OF INTEGRATION

Power system planners can provide valuable information to fish and wildlife managers to aid their development of measures to improve survival. Similarly, fish and wildlife managers can provide data to power planners so that they can plan for resource mixes that minimize impacts to fish and wildlife, whenever possible.

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

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

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

In addition, physical and economic analysis of specific fish and wildlife measures can aid in the development of a fish and wildlife curtailment policy, in the event of a power emergency. It would be in the region's interest to have a policy in place prior to an emergency, in order to minimize the risk to fish and wildlife. The following section provides a description of the mainstem measures under the fish and wildlife program and an analysis of their cost.

## COMPONENTS OF A FISH AND WILDLIFE OPERATION

The mainstem portion of the fish and wildlife program consists of two major types of actions to promote survival that will also affect the power supply; 1) flow augmentation and 2) bypass spill.[5]

### Flow Augmentation

Monthly flow objectives are provided for both the Snake and Columbia rivers during the migration season (April through August). These flow objectives, however, cannot be achieved 100 percent of the time because our reservoir system simply cannot store enough water to make up the difference in dry years. The BiOp makes considerations for extremely dry years and for the large uncertainty in forecasting runoff volumes. Language in the BiOp directs spring refill curves at Grand Coulee to be developed using an 85 percent level of confidence (assuming that sufficient non-hydro resources are available for winter power needs). Refill curves at Libby, Hungry Horse and Dworshak are developed using a 75 percent level of confidence. Realistically, because of other higher priority constraints, these refill probabilities are not always achieved. In simulated operations, Grand Coulee refills 84 percent of the time and Libby, Horse and Dworshak refill 40 percent, 58 percent and 66 percent, respectively.

When analyses are done using the existing non-hydro resources in a probabilistic manner (i.e. simulating forced outages), reservoirs must sometimes be drafted below their operating rule curves during winter months to sustain electricity service. This use of hydro is often referred to as "hydro flexibility." Hydro flexibility is used to make up energy needs during cold snaps or periods when imports from out-of-region utilities are not available or during the outage of a major power system component. The additional water drafted to produce the extra energy is replaced as soon as possible,

[5] See the Council's 2003 Fish and Wildlife program and NOAA Fisheries' 2000 Biological Opinion.

even if energy must be imported. Most often reservoirs can recover and get back to the projected refill elevations by spring. In the event that hydro flexibility cannot be replaced by spring, then less water is available for flow augmentation through spring and summer.

## Bypass Spill

During the summer, flow augmentation measures in the BiOp actually provide more generation from the hydroelectric system because they increase river flow. However, bypass spill, which diverts water around turbines, reduces generation and reactive support for the transmission system.[6] Bypass spill can be curtailed for two reasons; 1) due to summer power emergencies (which should be more rare than winter emergencies) or 2) to refill reservoirs to minimum end-of-summer elevations as specified in the BiOp or the Council's fish and wildlife program. Bypass spill could also be curtailed in order to store additional water in Canadian reservoirs as a safeguard for anticipated winter problems in an upcoming winter, as was the case in 2001.

## Measuring the Success Rate of Providing Fish and Wildlife Operations

The BiOp allows for curtailment of fish and wildlife operations during power emergencies but it does not specify an upper bound for such actions. For a number of reasons (i.e. what occurred during the 1990s) it could happen that the region under builds its generation supply, which increases the likelihood of having to curtail fish and wildlife operations. Using curtailment of fish and wildlife operations as a "safety valve" for an inadequate power supply is not acceptable. Curtailment of fish and wildlife operations cannot be used in lieu of planning for and acquiring an adequate regional power supply.

As a possible method of quantitatively measuring the likelihood of curtailment to fish and wildlife operations, a probabilistic metric (similar to the loss of load probability) can be developed. The simulation models used to calculate the reliability of the power system can also readily provide an assessment of how often fish and wildlife operations would be curtailed. The model can count how often reservoirs do not reach the desired pre-migration elevations and also how often bypass spill would be curtailed to avoid power shortfalls.

Council staff has developed a prototype metric and has solicited comments from a wide range of agencies and organizations in the region. While there was significant interest and support for developing such a metric, it became clear that more regional analysis and debate would be required before such a metric could be implemented into the planning process. Problems yet to be resolved related to this metric are defining what a "significant" curtailment is and how often curtailments would be allowed (that is, setting a standard). Future discussion of this approach should be discussed in the long-term planning committee that the Council is recommending to be established.

# COST OF INDIVIDUAL FISH AND WILDLIFE MEASURES

The analysis presented here estimates the cost of individual measures in the fish and wildlife program. This effort is not designed to be a cost-effectiveness analysis. Rather, it is to be used to help the Council identify the most costly elements of the fish and wildlife program, which should be re-examined for biological effectiveness. The Council specified, in its fish and wildlife program, that such measures, especially bypass spill, should be revisited in terms of assessing their biological

[6] See the February 24, 1998 memorandum from John Fazio to the Council members regarding the transmission impacts of drawing down John Day Dam (Council document 98-3).

benefits. During that process benefits to fish and wildlife from alternative main stem operations and their effects on the power system should also be examined.

## Methodology

This analysis begins with a simulation of current river operations (BiOp). The simulation is performed with the GENESYS model.[7] Each subsequent study repeats the simulation but with one fish and wildlife measure removed. For each case study, the energy produced is compared to that in the base case and power system cost is calculated. This effectively determines the cost of each fish and wildlife measure analyzed. The measures are then ranked by cost.

It should be noted that fish and wildlife measures are not totally independent of each other. In other words, the cost of removing two measures will be different than the sum of the costs of removing each individually. Some measures, such as winter storage and flow augmentation are more dependent than others, such as bypass spill. However, performing the analysis as if each measure were independent provides a good first pass approximation. Once the data has been examined, the most expensive measures can be analyzed in more detail.

The key output parameter is annual-average regional power-system cost. That value is calculated by multiplying the difference in monthly hydroelectric energy production between the base case and a study case with the forecasted monthly market electricity price.[8] When the study case produces less energy, the difference is assumed to be purchased on the market and represents a cost. When the study case produces a surplus, the difference is sold on the market and represents revenue that offsets purchase costs. This calculation is performed for each month of the year, simulated over the 50-year historical water record.

The power system cost calculated for this analysis does not include costs of implementing fish and wildlife measures. It also does not include costs associated with loss of capacity or loss of transmission capability. Future analysis with the GENESYS model can shed some light on potential capacity problems associated with fish and wildlife measures. Those costs are not insignificant but it is believed, in most cases, that they are small compared to energy costs.

## Results

Simulation results compare hydroelectric generation from the base case with that from the various scenarios analyzed. The monthly change in generation is multiplied by the wholesale electricity price (shown in Figure 1[9]) to compute the net gain or loss of revenue. Decreases in generation are assumed to be made up with purchases from the market and increases in generation are assumed to be sold into the market. By adding up the monthly purchases or sales over all water conditions, the average annual net cost or benefit of a particular scenario can be calculated for the region. Figure 2 below illustrates the range of annual costs for the entire BiOp. The average annual cost is $410 million. To put this in perspective, Bonneville's annual net revenue requirement is in the range of $3.5 billion. Thus, the BiOp cost is a little more than 10 percent of Bonneville's net revenue

[7] See http://www.nwcouncil.org/genesys.
[8] Electricity prices are forecast using the Aurora model, created and leased by EPIS.
[9] It should be noted that the long-term forecast electricity price drops from the 2006 average of about $43/megawatt-hour to about $30/megawatt-hour by the year 2010. The forecast price then rises gradually to a little over $35/megawatt-hour by 2025. This means that in real terms, the costs for fish and wildlife measures will be lower in future years relative to their cost for 2006.

requirement. Energy-wise, the BiOp has decreased average hydroelectric generation by about 1,100 average megawatts or about 10 percent of the firm hydro energy capability.

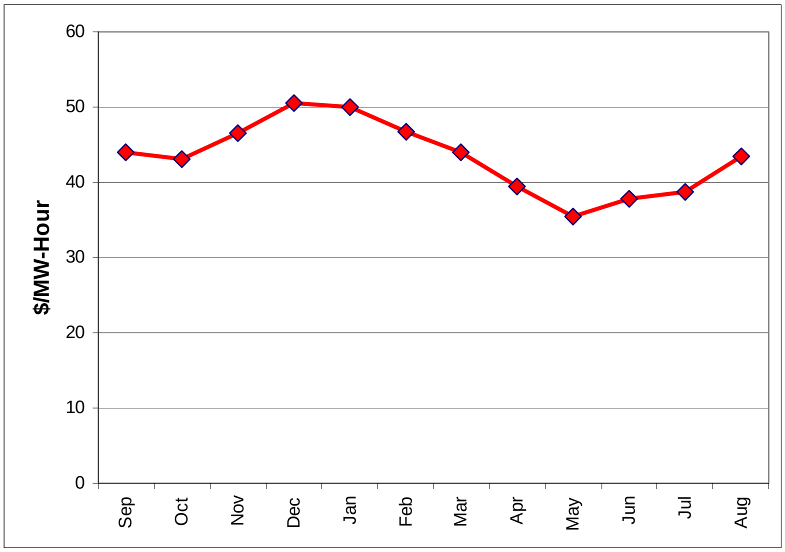


**Figure O-1: Forecast Bulk Electricity Prices (at Mid-Columbia, 2006 operating year, 2004 dollars)**

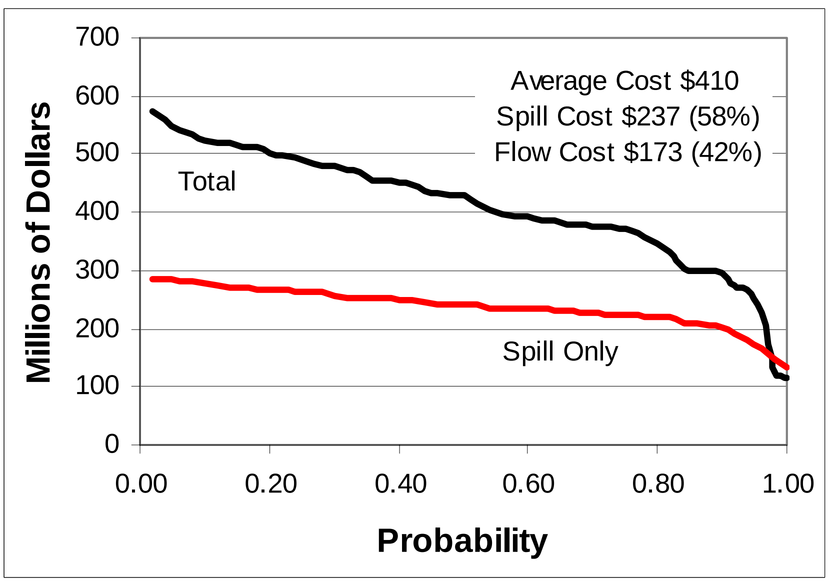


**Figure O-2: Range of Annual Cost for Fish and Wildlife Operations (2006 operating year, 2004 dollars)**

Annual BiOp costs range from a high of about $600 million to a low of about $100 million. In order to explain why some years have low costs, we must describe in more detail the two major components of fish and wildlife operations -- flow augmentation and bypass spill. Holding water back during winter months for release in spring and summer months effectively moves hydroelectric generation from months when the average price is about $50/MW-hour into spring months when the price can be as low as $35/MW-hour and into the summer months when the price can still be lower than the winter price. (There are also energy efficiencies to take into account but their impact is small relative to the shift in prices). Depending on how much water (energy) is moved into spring vs. summer, the range of economic impacts for flow augmentation is very large (Figure 2). There may be some situations when summer prices are higher than winter prices, in which case, flow augmentation actions could improve revenues. Unfortunately, the effects of bypass spill overwhelm any economic benefits derived from such situations.

Bypass spill is water that is routed around the turbines to enhance survival of migrating smolts. It always represents a loss of revenues for the region. At some projects, bypass spill is defined to be a fraction of outflow and at other projects it is defined as a flat amount. Both are subject to maximum spill levels that limit gas supersaturation to no more than 120 percent. The cost of spill varies with water conditions and prices. Figure 3 illustrates the annual breakdown of flow augmentation and bypass spill costs for the region. Overall, bypass spill costs represent about 58 percent of the total average cost of the BiOp. That percentage varies quite a bit as demonstrated in Figure 3.

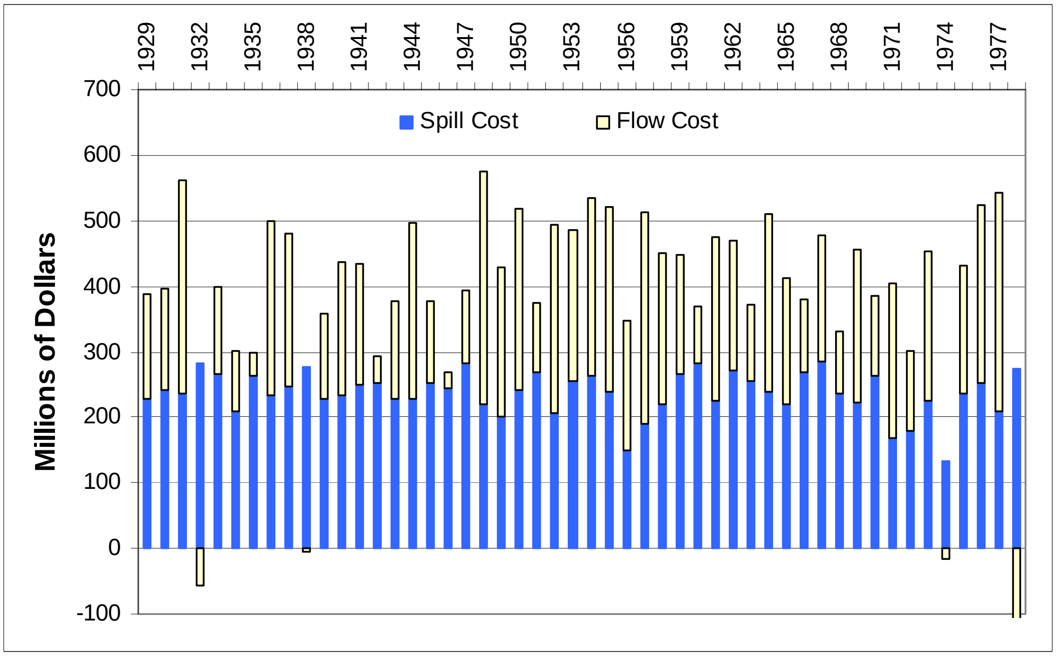


**Figure O-3: Flow and Bypass Spill Cost by Water Condition (2006 operating year, 2004 dollars)**

It is of interest to understand how fish and wildlife operation costs vary with water conditions. Figure 4 below plots the cost of both flow augmentation and bypass spill as a function of the January-to-July runoff volume as measured at The Dalles. The flow augmentation costs are represented by the square points in that figure and do not show any particular pattern, except that they may perhaps decrease slightly as runoff volume increases. This makes some intuitive sense since less water must be shifted from winter months into spring and summer months in wet years to attempt to achieve BiOp flow objectives.

Bypass spill costs however, behave in a very different manner. Figure 5 illustrates only the spill costs as a function of runoff volume. As runoff conditions increase, so do bypass spill costs but only up to a point. For more-or-less average water conditions spill costs seem to level off. For wet years, bypass spill costs actually decrease. This apparently unusual relationship between spill and costs can be explained fairly easily. At some projects, bypass spill is a percentage of outflow -- meaning that as the outflow increases (or as runoff volume increases) the absolute volume of spill also increases. However, this trend is limited by the gas supersaturation constraint. That is, once the absolute volume of spill reaches the gas limit, no more volume is spilled. In this case, the cost of bypass spill remains constant until the runoff volume increases to a point where the hydraulic capacity of the project is exceeded. In that case, the amount of bypass spill is reduced so that the total spill (bypass and forced) equals the desired amount. Because forced spill (flow exceeding hydraulic capacity) would occur anyway, there is no cost associated with it and the cost of the declining bypass spill decreases. This phenomenon is illustrated in Figure 6.

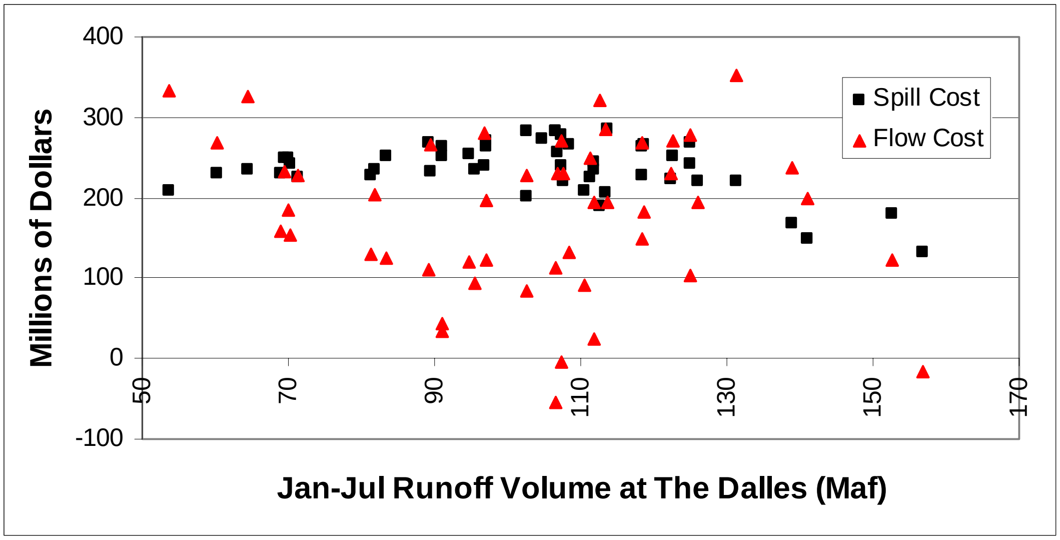


**Figure O-4: Flow and Spill Cost as a function of Runoff Volume (2006 operating year, 2004 dollars)**

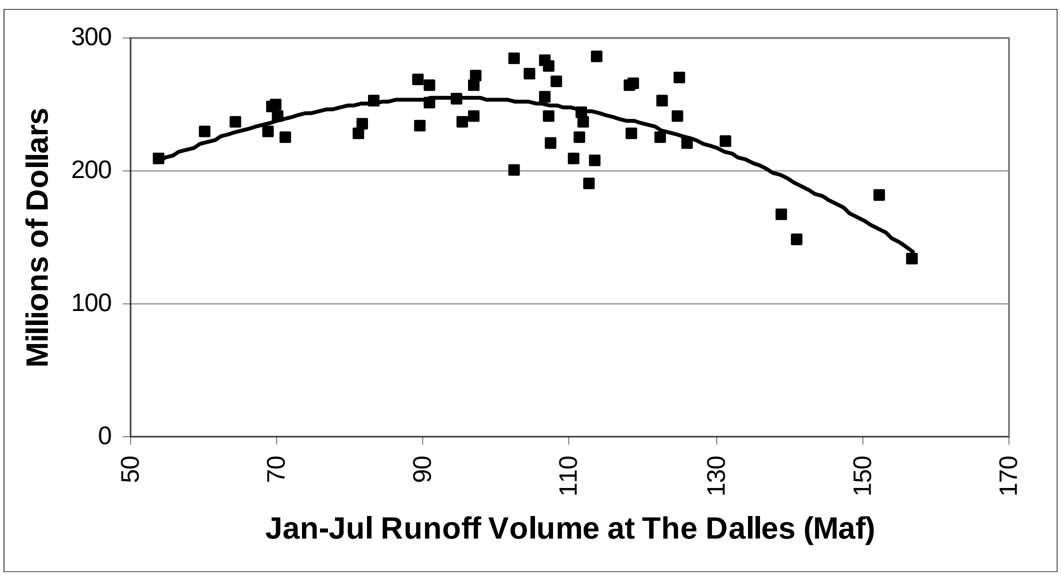


**Figure O-5: Bypass Spill Cost as a function of Runoff Volume (2006 operating year, 2004 dollars)**

It is of no great surprise that bypass spill shows the greatest cost to the power system in most years. Not only does the region lose energy when providing spill but it also limits the peaking capability of the project and in some cases may reduce reactive support for the transmission system. The later impact effectively reduces the transfer capability of nearby transmission lines.[10]

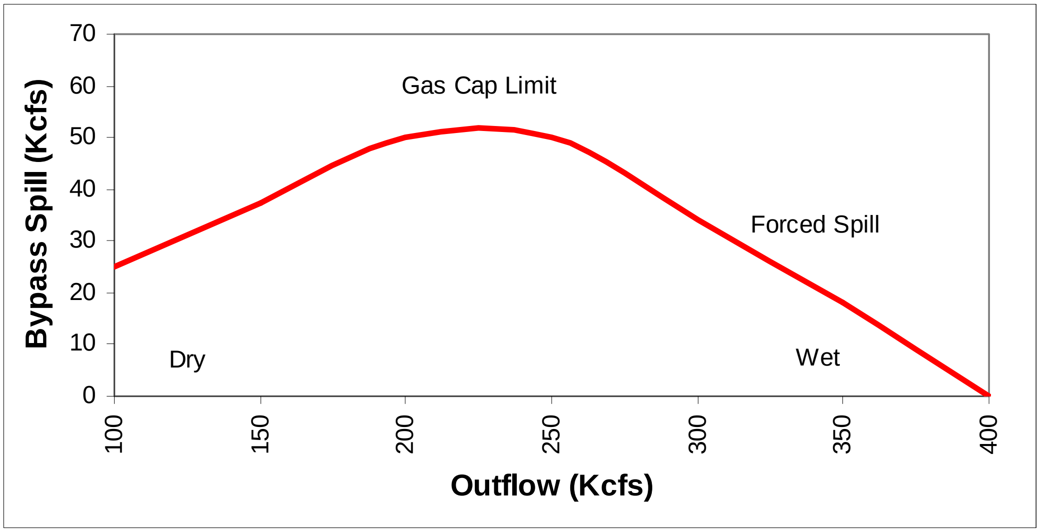


**Figure O-6: Illustration of Bypass Spill Flow as a function of Outflow**

Because of the Council's commitment to re-examine bypass spill, the remaining analysis focuses on that operation. Table 1 below identifies the energy loss and associated costs of providing bypass spill at the eight lower river dams for both spring and summer periods. From Table O-1, it is clear that bypass spill at The Dalles and John Day is the most costly. In fact, bypass spill costs at those two projects make up almost half of the total spill cost. If any research money is to be spent, it should focus on these two projects and perhaps Ice Harbor.

Figures 7 and 8 illustrate the cost of bypass spill in graphic form. Figure 7 shows the average cost for bypass spill at each of the eight lower river dams. Figure 8 breaks those costs down into spring and summer periods, just like the data in Table 1. Using this information helps direct money and research efforts to the right projects.

[10] See Council document number 98-3.

**Table O-1: Annual Average Cost and Energy Loss of Bypass Spill (2006 operating year, 2004 dollars)**

| Project/Season | Cost (Millions $) | Energy Loss (MW-Hours) |
|---|---|---|
| John Day/Summer | 31.1 | 766,810 |
| John Day/Spring | 29.6 | 791,895 |
| Ice Harbor/Spring | 28.6 | 742,361 |
| The Dalles/Spring | 27.5 | 735,028 |
| The Dalles/Summer | 25.6 | 625,399 |
| Bonneville/Summer | 23.3 | 560,671 |
| Bonneville/Spring | 20.7 | 542,524 |
| McNary/Summer | 12.2 | 306,571 |
| Ice Harbor/Summer | 11.8 | 292,441 |
| McNary/Spring | 10.6 | 276,784 |
| Lower Monumental/Spring | 8.8 | 233,917 |
| Little Goose/Spring | 4.1 | 109,644 |
| Lower Granite/Spring | 3.3 | 87,504 |
| **Total (energy loss in average megawatts)** | **237** | **693** |

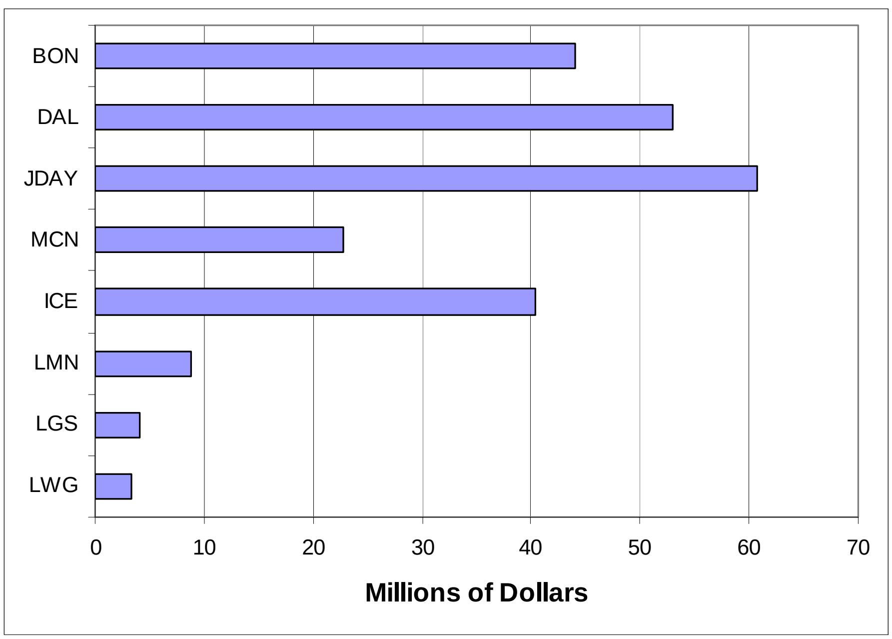


**Figure O-7: Bypass Spill Cost by Project (2006 operating year, 2004 dollars)**

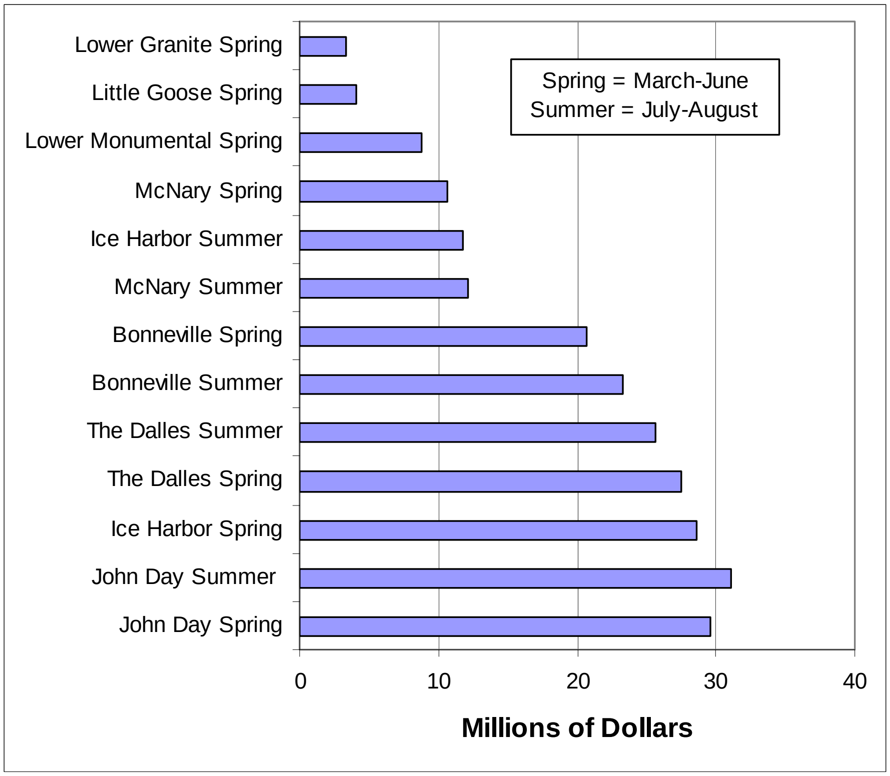


**Figure O-8: Bypass Spill Cost by Project and by Season (2006 operating year, 2004 dollars)**

# Risk and Uncertainty

This appendix deals with the representation of uncertainties and risks in the plan's regional model.[1] It also describes the various studies the Council has performed to understand how the Council's perception of risk and uncertainty bear on its recommendations. A glossary, index, and list of references appear at the end.

This appendix addresses the regional model itself to a limited extent. This appendix identifies a particular range of the model worksheet cells that creates a model "future," the single draw of each source of uncertainty over the study horizon. In the section on "Uncertainties," beginning on page P-19, it describes in detail how the regional portfolio model manifests these modeling futures with Excel® formulas and user-defined functions. The description of the rest of the model, however, appears in Appendix L.

| ICON KEY |
|---|
| Key idea |
| Definition |

This appendix provides several tools to help the reader track this discussion. The first tool is the use of icons to flag key definitions and concepts. A table of these icons appears that the left.

The second tool is a set of workbooks containing versions of the regional model, utilities, and a document that describes particular worksheets. The reader can request a copy of these workbooks from the Council or download them from the Council's web site.[2] The first of these files is a compressed file containing the workbooks that Appendix L uses, L24X-DW02-P.zip. In particular, L24DW02-f06-P.xls is a workbook containing a pre-draft plan version the regional portfolio model. The compressed file also contains examples of utilities and documentation. References to the workbook L24DW02-f06-P.xls appear in curly brackets ("{}"). The second file is L28_P.zip, which contains the workbook L28_P.xls, the regional model that the final plan's preparation used. Note that the treatment of several key sources of uncertainty changed significantly between the draft and final plan. A document in L28_P.zip describes the changes. References to L28_P.xls appear in double curly brackets ("{{}}"). Access to the workbooks should not be necessary for following the discussion in this appendix, however.

References to Council work papers and data sources appear in square brackets ("[]"). The "References" section at the end of the appendix lists these sources. Other publicly available sources appear in footnotes. The reader may want to refer to the following Table of Contents for orientation to the remaining appendix.

[1] The reader will find definitions for terms such as "uncertainty," "risk," and "futures" in the glossary. Chapter 6 of the plan also defines and illustrates these terms with examples.
[2] As of this writing, http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/

# Table of Contents

# *Introduction*

This appendix begins with a discussion of the Council's approach to decision making under uncertainty. This shapes the means of and choice of tools for addressing uncertainty. It also influences the validation of analyses and models. The issue of validation arises not only in the formal validation of the model futures but extents to basic judgments about assumptions, as well. The Appendix will return many times to the issue of whether the judgments about assumption values are reasonable in the section on "Uncertainties."

Between its discussion of the Council's approach to decision making under uncertainty and the validation of data and models, the appendix introduces the regional model. This serves several purposes. First, the next main section is about the Council's treatment of uncertainties. As mentioned earlier, this appendix identifies a particular range of the model worksheet cells that creates a model "future," the single draw of each source of uncertainty over the study horizon. This introduction identifies that range. The introduction also gives the reader an overview of the philosophy and methods for modeling uncertainty. It describes, for example, the use of Monte Carlo simulation and how the application this technique facilitates the Council's approach to decision making. Second, it identifies how the model produces its principal results, the distribution of present value total system costs and associated risk and central tendency measures. This is the topic of the next main section of this appendix, "Risk Measures." Third, the introduction provides a concrete framework for the discussion of the last section, "Sensitivity Studies." This last section examines not only the purpose and conclusions of the studies, but how Council staff modified the regional model to obtain the results. Finally, the introduction mentions utilities that access regional model output to assist interested parties to perform their own validation of the model's assumptions and results.

## Decision Making Under Uncertainty

Strategic decision-making models ***use and manage uncertainty*** differently from many simulation models that incorporate uncertainty. The key difference between the two is the scale of risk and how a decision maker responds to uncertain events.

An example of a simulation that addresses uncertainty, but is not what we would call strategic decision analysis, is how many utilities model hydrogeneration. To simulate generation due to hydro streamflow variability, an analyst would create a model using some sample of historical data, say 1939 through 1978 streamflows. The analyst has a great deal of information about the distribution of streamflows. He may be willing to assume that the underlying processes that give rise to the streamflows – and the relationship between generation and stream flows – are stable. Because the variation in hydrogeneration averages out over a sufficient number of years with high probability, the average generation and average system cost are useful statistics, and may be the key outputs of interest.

The decision maker may need to make a choice among different plans to deal with this variation in hydrogeneration, but the tool she uses is essentially sensitivity analysis, albeit sophisticated sensitivity analysis. This kind of analysis is appropriate where the scale of the uncertainty and risk is small enough that the decision maker feels she can live with the outcomes, given the selected plan. In particular, the emphasis is on choosing a plan to which the decision maker feels comfortable committing.

This approach is common to many kinds of analysis. For example, it would be the way an industrial engineer would represent a manufacturing process, if he wanted to maximize throughput. It is the way a civil engineer would model traffic flow, if he were trying to minimize congestion or travel time.

Against these examples, contrast strategic decision analysis. If the scale of change is large, extreme outcomes may be catastrophic. If the outcome would be catastrophic, the decision maker may need to consider individual scenarios. The way each scenario turns out would typically determine how the decision maker would respond to circumstances. Scenario analysis will focus on developing options, deciding what circumstances would trigger the implementation of each option, and evaluating the benefits of using each option. Scenario analysis usually has decision rules or "flags" that tell the decision maker when to change plans or implement options.

An example of strategic decision analysis is planning for a military operation. In the fog of war, leaders must make life or death decisions about tactic and strategy. In addition to the main plan, strategists will develop Plan B, Plan C, and so forth, alternatives to implement if circumstances are not as expected. They create options by deploying resources and small numbers of troops to monitor enemy activity and serve as support if it becomes necessary to adapt to new scenarios.

Note that a general would never consider implementing a fixed strategy, one without options or alternatives, based on average survival. If an option will spare a life, it merits consideration. Whereas the average hydro generation over five or six years is a useful number for certain calculations, such as average power cost, failing to adapt military plans because the expected distribution was acceptable would be ludicrous and tragic. In decision analysis, the tails of the distribution, especially the "bad" tail, assumes greater significance than they do in ordinary simulations. Adaptations that improve the outcomes in the worst of circumstances receive emphasis. Decision making under uncertainty has more to do with making decisions that, while they may not have been optimal in retrospect, did not lead to a catastrophic outcome. This appendix returns to the discussion of managing bad outcomes in the section "Risk Measures."

One of the issues that a decision maker who is making decisions under strategic uncertainty must grapple with is the relative likelihood of each scenario. This issue is central to the question of how much to spend on a given option. If the decision maker believes that scenario A is much more likely than scenario B, which has the same cost, the decision maker might be inclined to spend more to mitigate scenario A. Another difficulty that sometimes arises in scenario analysis is that a decision maker can only evaluate a small number of scenarios. The question arises, "How were these scenarios selected, and how representative are they?"

The next section introduces to a technique, Monte Carlo simulation, which helps address concerns about the likelihood and range of scenarios. The regional model employs Monte Carlo simulation. The regional model, however, also implements planning flexibility. Planning flexibility, described in Appendix L, enables the regional model to evaluate contingency plans and implement those plans as circumstances change during each scenario's study period. Therefore, the regional model performs true strategic decision analysis on a large number of scenarios, effectively "scenario analysis on steroids."

Another distinction of decision analysis models is how one validates the models. The section that follows the next section discusses those differences.

## Monte Carlo Simulation

"Monte Carlo simulation" refers to any method that solves a problem by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems that are too complicated to solve analytically.[3] In 1946, S. Ulam became the first mathematician to dignify this approach with a name, in honor of a relative having a propensity to gamble (Hoffman 1998, p. 239). Ulam was involved with the Manhattan project to build the first atomic bomb. Physicists used the technique for evaluating complex integrals.

The Council applies the Monte Carlo technique to regional resource planning to generate futures based on the likelihood of particular values of each source of uncertainty in each modeling period of the regional model:

- Load requirements
- Gas price
- Hydrogeneration
- Electricity price
- Forced outage rates
- Aluminum price
- $CO_2$ tax
- Production tax credits
- Green tag value

The regional model performs true strategic decision analysis on a large number of scenarios, effectively "scenario analysis on steroids."

The technique produces values for each source that have the correct correlation with previous values and with values of the other sources.

[3] The interested reader can consult any of a host of books and Internet resources describing Monte Carlo simulation in general.

The principal reason for using Monte Carlo simulation for decision analysis, however, is that it avoids what the Richard Bellman referred to as the "curse of dimensionality."[4] To evaluate the outcomes associated with values of uncertainties, an analyst can construct a "decision tree" that associates with each combination of values for the various sources a probability and outcome. The problem, however, is that the "branches" of the decision tree proliferate exponentially with the number of uncertainties addressed. For example, a decision tree with three values of electricity price forecasts ("high," "medium," and "low") would require only three studies. A decision tree large enough to examine three forecasts for each of the nine uncertainties listed above, however, requires $19{,}683 = 3^9$ studies. The regional model uses 750 values for each of 1045 random variables to represent values in each of the model's 80 periods, which would produce $750^{1045}$ branches. This number of branches far exceeds the storage capability of any machine imaginable. The regional model, moreover, must perform this calculation roughly a million times to produce a single feasibility space, described below.

Of course, not all of the branches of a decision tree have sufficiently high probability and extreme value that they would contribute much to the solution. It is this observation that leads to Monte Carlo simulation. Monte Carlo simulation chooses random values for each source of uncertainty according to their likelihood.[5] The distribution that results therefore automatically reflects both the likelihood and value of the outcome. Because Monte Carlo simulation is a statistical sampling technique, the criterion for the number of samples is the confidence necessary for statistics of interest, such as the error of the mean or of the mean of a tail. This sample size is typically only weakly sensitive to the number of sources of uncertainty.

The regional model uses Decisioneering Inc.'s Crystal Ball® Excel add-in to perform Monte Carlo simulation. Crystal Ball uses particular terms to refer to the Excel worksheet cells that perform the principal tasks.

**Assumption Cells** are worksheet cells in a spreadsheet model that contain a value defined by a probability distribution's random variable. These cells are distinguished in the sample workbooks by their distinctive green color. (See, for example, {{R24}}.) This appendix regularly refers to assumption cells in the section "Uncertainties." Crystal Ball reassigns values to each assumption cell at the beginning of each "game" or modeling future.

A **Decision Cell** is a worksheet cell in a spreadsheet model that the user controls. The user controls these indirectly – for example, via an optimizer – or directly. The reader may think of the value of these cells as representing the plan. The optimization program adjusts the decision cells in the regional portfolio model to minimize cost, subject to risk

[4] Bellman, R. (1961), Adaptive Control Processes: A Guided Tour, Princeton University Press.

[5] For a number of good reasons, these values are not truly random in the everyday sense of the word. For example, the random number generator uses a seed value, so that an analyst can reproduce each future exactly for subsequent study. The generator also selects the values to provide a more representative sampling of the underlying distribution, a technique known as Latin Hyper Square or Latin Hyper Cube.

constraints. Appendix L details the function and application of decision cells in the section "Parameters Describing the Plan," page L-72. These cells are yellow in the regional model. (See, for example, {{R2}}.)

**Forecast Cells** contain statistical output of the model. The default color for these cells is turquoise. In the regional model, the primary forecast cell is the NPV cost for a plan under a 20-year future, {{CV1045}}. Other forecast cells in the regional model, such as those that regional model macros assign risk values, serve to communicate data back to the OptQuest optimizer.

The assumption and decision cells are, in a sense, the exogenous inputs to the model; the forecast cells report the output. The topic of the next section is the calculation engine that processes the input and produces the output.

## Logic Structure of the Portfolio Model

To understand how the regional portfolio model represents uncertainty and generates the system cost values that give rise to risk, it is useful to understand the model itself. The treatment of uncertainties, like load and hydro generation, are to some extent separable from the rest of the model. This section identifies a particular range of the model worksheet cells that creates futures. (See page P-15.) Likewise, the forecast cells that report the final costs and risks inhabit a small range of adjacent cells. The description of the rest of the model appears in Appendix L. The following provides a brief introduction that should be sufficient for understanding that portion of the model that simulates sources of uncertainty.

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

Given a particular future, the primary measure of a plan is its net-present value total system costs. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), certain short-term purchases, and fixed costs associated with future capital investment and O&M. The present value calculation discounts future costs to constant 2004 dollars using a real discount rate of four percent.[6]

If the future were certain, net present value system cost would be the only measure of a plan's performance. Because the future is uncertain, however, it is necessary to evaluate a plan over a large number of possible futures. Complete characterization of the plan under uncertainty would require capturing the distribution of outcomes over all futures, as illustrated in Figure P-1 below. Each box in Figure P-1 represents the net present value cost for a scenario sorted into "bins." Each bin is a narrow range of net present value total system costs. A scenario is a plan under one particular future.

[6] See Appendix L.

Because a simulation typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make manageable the task of capturing the nature of a complex distribution. The *expected* net present value total system cost captures the central tendency of the distribution. The expected net present value is the average of net present value total system costs, where the average is frequency weighted over futures. This plan will often use the shorthand expression, "average cost of the plan." The average cost is identified in Figure P-1.

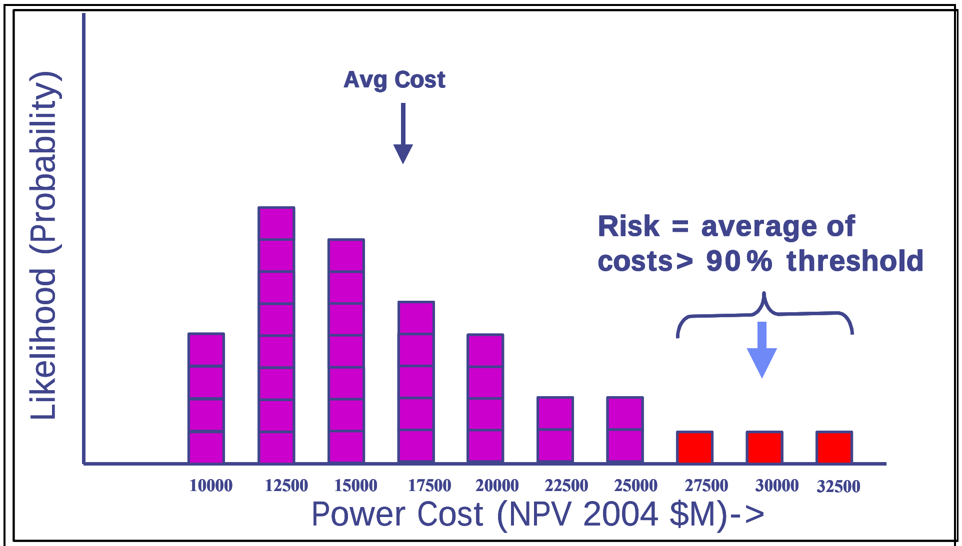


**Figure P-1: Plan Cost Distribution, Average Cost and Risk (TailVaR90 )**

Expected net present value cost, however, does not give a picture of the risk associated with the plan. There are a number of possible risk measures that could be used. A summary measure of risk called "TailVa$R_{90}$" was chosen. A discussion of this choice of risk measure and its comparison with other risk measures appears in section "Risk Measures," below. Very briefly, TailVa$R_{90}$ is the average value for the worst 10 percent of outcomes. It belongs to the class of "coherent" risk measures that possess mathematical properties superior to alternative risk measures. Since 1998, when papers on coherent measures first appeared, the actuarial and insurance industries have moved to adopt these, abandoning non-coherent measures such as standard deviation and Value at Risk (VaR).

Figure P-1 represents the cost distribution associated ***with a single plan***. If the outcomes for different plans are plotted as points, with coordinates given by the expected cost and risk of each plan, one obtains the new distribution illustrated in Figure P-2. Each point on the figure represents the average cost and TailVa$r_{90}$ value for a particular plan over all futures. The least-cost outcome for each level of risk falls on the left edge of the distribution in the figure. The combination of all such least-cost outcomes is called the "efficient frontier." Each outcome on the efficient frontier is preferable to the outcomes to the right of it, since it has the same risk as those outcomes, but lowest cost. Choosing from among the outcomes on the efficient frontier, however, requires accepting more risk in exchange for lower cost, or vice versa. The "best" outcome on the efficient frontier depends on the risk that can be accepted.

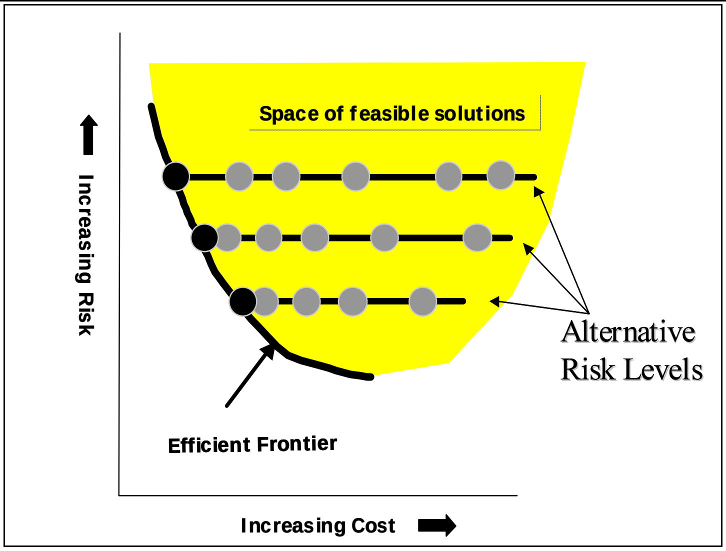


**Figure P-2: Feasibility Space**

When a user opens the portfolio model workbook, the values they see are values for a particular future and for a particular plan. It is within this future or "game" that the energy and cost calculations take place. How, then, are the futures changed to create a cost distribution for a plan and the plans changed to create the feasibility space?

Figure P-3 illustrates the overall logic structure for the modeling process. The optimization application, the Decisioneering, Inc. OptQuest™ Excel® add-in, controls the outer-most loop. The goal of the outer-most loop is to determine the least-cost plan for each level of risk. It does so by starting with an arbitrary plan, determining its cost and risk, and refining the plan until refinements no longer yield improvements. The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with equal (or lower) risk but lower cost. The process ends when we have found a least-cost plan for each level of risk. This process is a form of non-linear stochastic optimization.[7]

[7] The interested reader can find a more complete, mathematical description of the optimization logic in reference the following references:
Glover, F., J. P. Kelly, and M. Laguna. "The OptQuest Approach to Crystal Ball Simulation Optimization." Graduate School of Business, University of Colorado (1998). Available at http://www.decisioneering.com/optquest/methodology.html ;
M. Laguna. "Metaheuristic Optimization with Evolver, Genocop, and OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/comparisons.html; and
M. Laguna. "Optimization of Complex Systems with OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/complexsystems.html

The optimizer OptQuest controls the Crystal Ball® Excel add-in. OptQuest hands a plan to Crystal Ball, which manifests the plan by setting the values of decision cells in the worksheet. These are the yellow cells in {range R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop, labeled "Monte Carlo Simulation," in Figure P-3. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest. For each future, Crystal Ball assigns random values to 1045 assumption cells, the dark green cells throughout the worksheet. (See for example, {R24}.) Crystal Ball then recalculates the workbook. In the portfolio model, however, automatic recalculation is undesirable, as described in Appendix L. The portfolio model therefore substitutes its own calculation scheme. It uses a special Crystal Ball feature that permits users to insert their own macros into the simulation cycle, as shown in Figure P-4. Before Crystal Ball gets results from the worksheet, a macro recalculates energy and cost, period by period, in the strict order illustrated in Figure P-5 and Figure P-6 and as described on page P-15. The reason for performing its own calculations is to assure calculations take place in a strict chronological order, as required by several mechanisms in the model, including the planning flexibility. The values in the Crystal Ball forecast cells then contain final net present value (NPV) costs that Crystal Ball saves until the end of the simulation. Forecast cells are those that have the simulation results and have a bright blue color. The NPV cost, for example, is in {CV1045}.

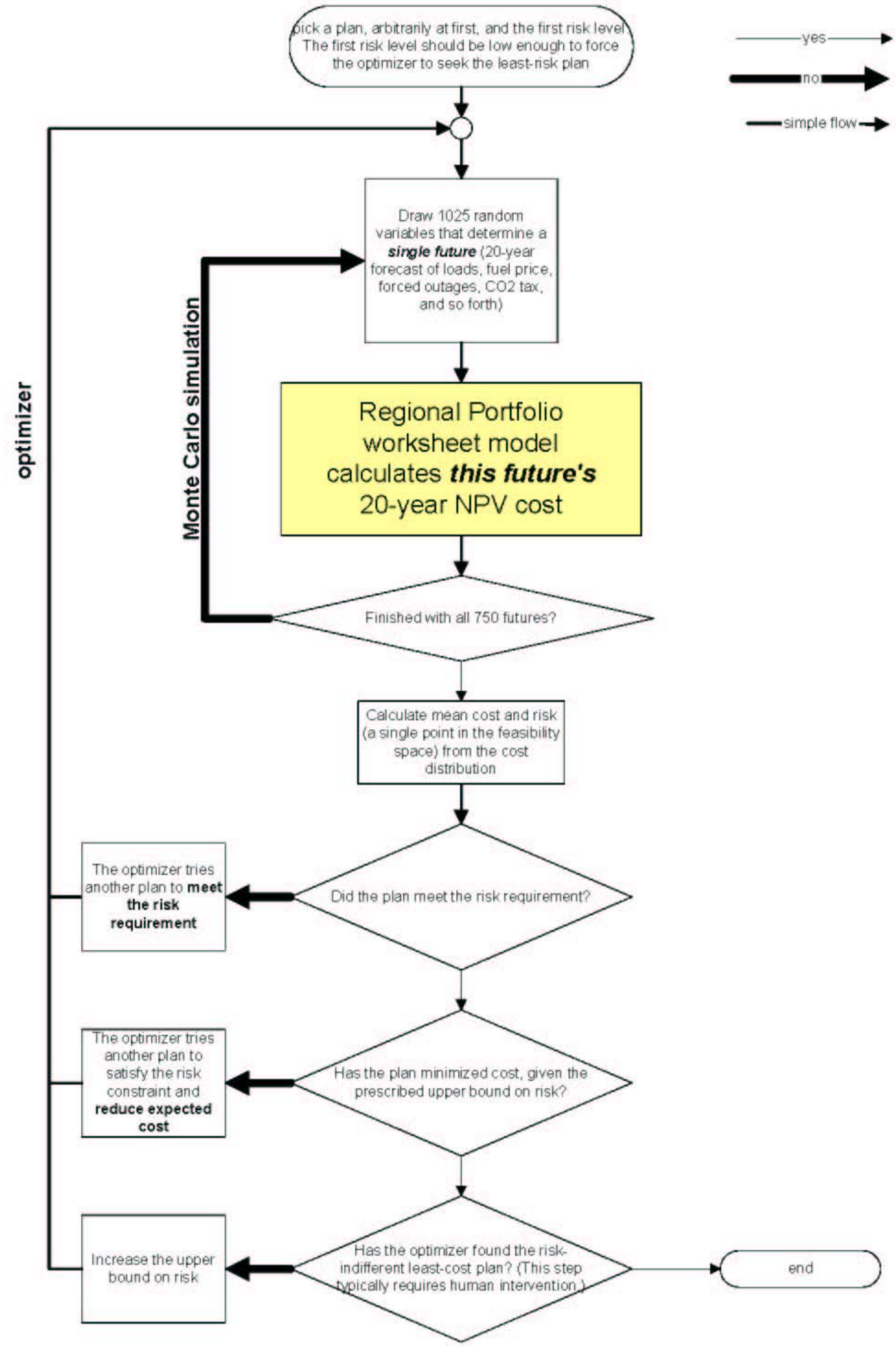


**Figure P-3: Logic Flow for Overall Risk Modeling**

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the last macro in Figure P-4 fires. This macro calculates the custom risk measures and updates their forecast cells. The custom risk measures include, for example, $TailVaR_{90}$, $CVaR_{20000}$, $VaR_{90}$, and the 90th Quintile.

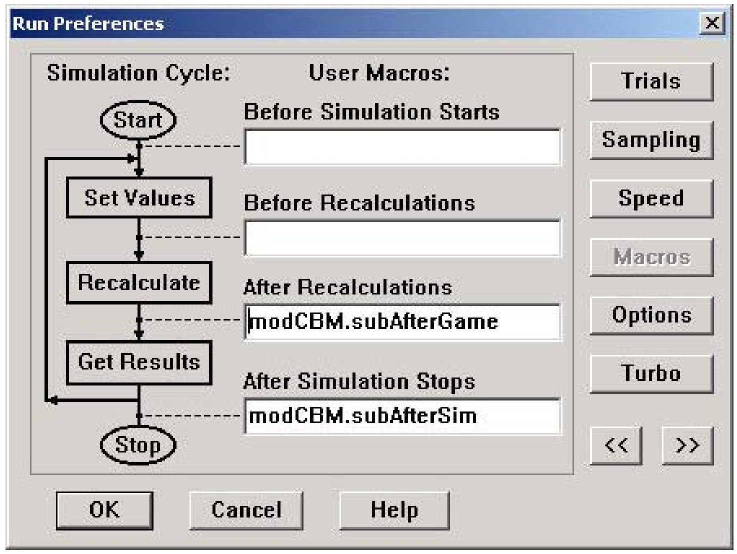


**Figure P-4: Crystal Balls Macro Loop**

***The portfolio model performs the duties of the innermost task, identified by the shaded box in Figure P-3.***



Given the values of random variables in assumption cells, the portfolio model constructs the futures, such as paths and jumps for load and gas price, forced outages for power plants, and aluminum prices over the 20-year study period. It does this only once per game. It then balances energy for each period, on- and off-peak and among areas, by adjusting the electricity price, as illustrated in Figure P-5. The regional portfolio model uses only two transmission zones, however, the region and the "rest of the interconnected system," although some it does model some geographic diversity of fuel and electricity price. Only after it iterates to a feasible solution for electricity price in one period does the calculation moves on to the next period. After calculating price, energy, and cost for each period, the model then determines the NPV cost of each portfolio element and sums those to obtain the system NPV. This sum is in a forecast cell.

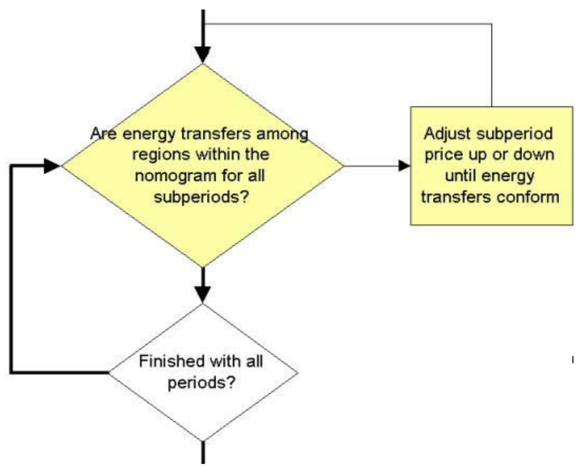


**Figure P-5: Logic in the Regional Portfolio Worksheet Model**

Some worksheet cells are involved in the energy rebalancing calculation. These cells, many of which contain formulas for electricity prices, must recalculate multiple times for each subperiod. These and other cells that rely on them, such as those that control the long-term interaction of futures, prices, and resources, are the "Twilight Zone" (TLZ) of the regional model. This portion of the worksheet also contains formulas for price elasticity of load and decision criteria.

Figure P-6 illustrates the calculation order described above. The number in the parentheses is the order. The plus sign (+) is a reminder that iterative calculations take place in the area. The workbook calculates the primary uncertainties only once per game, and their cells are near the top of the worksheet {rows 26-201}. (Plant forced outages are the exception. These cells are located elsewhere, as explained below and detailed on page P-84.) The cells associated with the uncertainties are denoted "Futures (1)" in Figure P-6.

The illustration denotes those recalculations that must be made multiple times per subperiod by TLZ {rows 202-321}. NP stands for on-peak {rows 318-682}; FP stands for off-peak {rows 684-1058}. The area at the far right refers to the NPV summary calculations {range CU318:CV1045}.

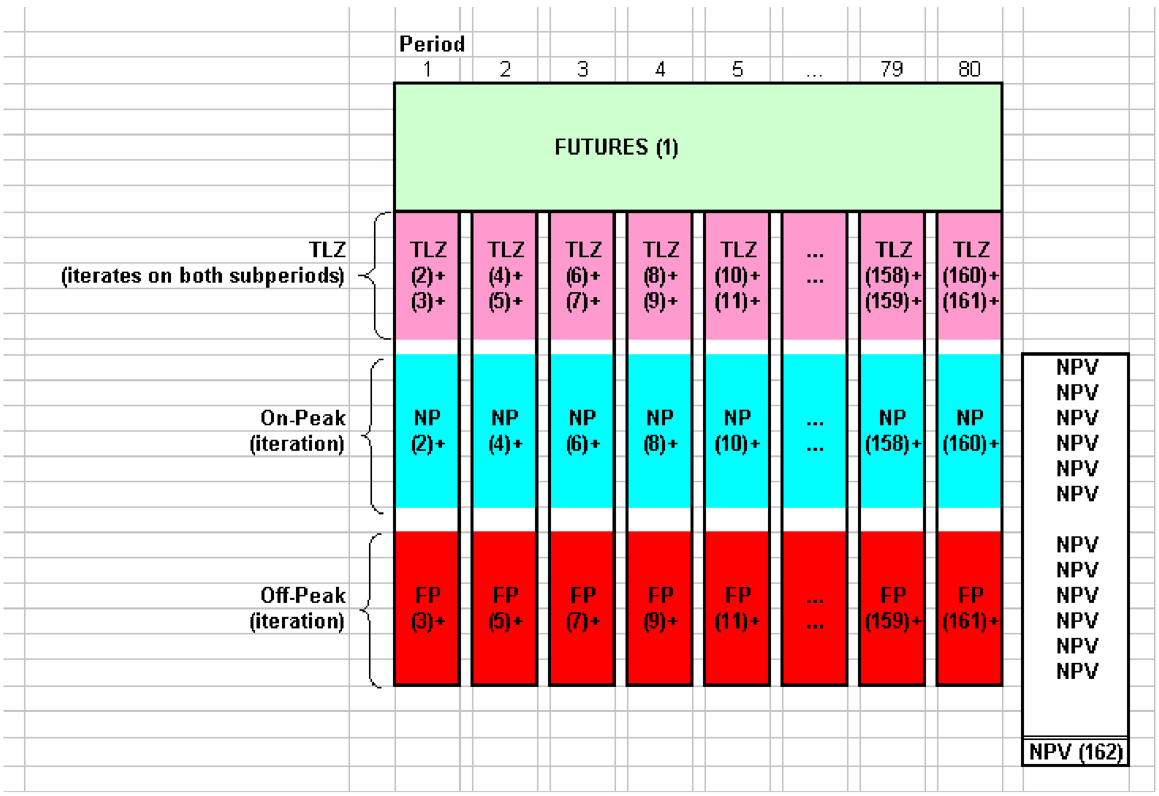


**Figure P-6: Portfolio Model Calculation Order**

Appendix P documents the uncertainties in the regional portfolio model. This includes the worksheet formulas for describing the uncertainties. Because it would be redundant to cover the same material in Appendix L, Appendix L describes everything *except* the uncertainties.

Figure P-6 permits us to state the scope of this appendix with respect to ranges within of the portfolio model. This **Appendix P**, and particular this section "Uncertainties," describes the calculations in the area of the worksheet denoted by "FUTURES (1)" and with the dark green assumption cells for plant forced outage associated with each power plant. For ease of reference, the worksheet calculates a future's forced outages in rows associated with the power plants themselves. Consequently, the user will find them not in the range marked "Futures (1)" in Figure P-6, but down in the rows associated with "NP" and "FP" calculations. **Appendix L** discusses all ranges of the regional model except that denoted by "FUTURES (1)".

## Model Validation

Given the differences between decision-making models and other simulation models that incorporate uncertainty, it should not be too surprising that how one validates the two differs. This section discusses some of those differences, with attention to the treatment of validation in the regional model.

The example of a simulation model that began this section was a hydrogeneration estimator. To validate the hydrogeneration model, an analyst would make some prediction about how the model would perform with a new set of streamflows. They would be concerned about how well the model reproduced certain patterns of generation. To validate their model they would then apply the model to a new set of historical streamflows, say 1979 through 1990, and compare the model generation with the actual generation over those years. An analyst would apply a similar process in constructing and validating simulation models for other systems where stochastic processes are important, such as for vehicle traffic flow or industrial manufacturing processes.

With strategic decision-making models, this approach does not work. The past is not a good standard for the future, because we have assumed our modeling futures differ dramatically from one another. It may be appropriate to look at a single future that resembles some past event to see how reasonable the model responds. This is effectively a one-point sample of possible futures, however. By design, there are many possible futures, and the model should prepare the decision maker for futures that unanticipated and unfamiliar.

This is not to say that there is no role for more traditional validation. There is a distinction, however, between short-term variation and strategic uncertainty. If we think of an example like electrical load requirements, we recognize there is some short-term variation due to weather and seasonality. We may tend to believe we understand this variation rather well and expect future variation to resemble that which we have seen in the past. This kind of variation lends itself well to statistical analysis of past behavior and patterns.

Once we attempt to forecast load requirements beyond a couple of years, however, we enter the realm of strategic uncertainty. We recognize there are many things that can affect system load requirements. Economic disruptions within and outside the region and technological innovations, for example, can greatly influence energy requirements. We may expect that there is strong chronological correlation in load requirements, i.e., load in a given month will not differ significantly from load in the previous month beyond what we expect from seasonal variation. The underlying tendency or path of system load requirements, however, can move in a host of different directions, so that after just a few years, system load requirements are significantly different from the expected forecast.

While previous statistical patterns may be helpful in validating the short-term variation behavior of the model, they do not help with strategic uncertainty. Fundamental models, which relate strategic behavior to underlying processes, can be helpful in understanding and reducing strategic uncertainty. Even fundamental models, however, rely on assumptions that are plagued by uncertainty once forecasts extend beyond a few years. Moreover, because of their associated computational burden, it is difficult to incorporate a fundamental model directly into a model for decision making under uncertainty.

Ultimately, the representation and validation of strategic uncertainty is highly subjective. Expert opinion, often formed through careful consideration of many sources of information, including the results of fundamental models, is the arbiter of credibility. When they are available, ranges of expert forecasts can help validate possible futures. The Council attempts to achieve regional model consistency with its forecasts for electricity load requirements and natural gas prices, for example.

This approach is certainly not without its shortcomings. Those who have examined case histories of decision making under uncertainty have noted that experts often overestimate their ability to forecast the future.[8] That is, experts tend to underestimate uncertainty. We do not have to look any further than the load forecasts made by utility experts in the 1970s and 1980s to find examples where each year, the load forecasts fell below the lower jaw of the previous years set of load forecasts. The Council's own oil price forecasts since the 1980s provide another example where actual prices repeatedly fell outside the range of bounding (high and low) forecasts [**1**]. (See Figure P-7.)

While recognizing these shortcomings, the Council has elected to validate the regional portfolio model using expert's review of the futures used in the model. In Appendix L, the reader will find a description of the utility for data extraction and Spinner graphs. This utility, and in particular the set of graphs embedded in the principal worksheet, permit anyone to quickly scan through all 750 futures. For each future, the user can simultaneously view the 20-year projection of electricity prices, loads, natural gas prices, and so forth, for that future. In addition, the user can also witnessed how power plants are built out under that future and how much energy generation there is by technology for each period under that future. They can view the period costs and net present value cost, and most of the other variables that an analyst would want to see to verify that the model

[8] See, for example, John T. Christian, Consulting Engineer, Waban, Massachusetts Geotechnical Engineering Reliability: *How well do we know what we are doing?* The 39th Terzaghi Lecture, Spring 2005 GeoEngineering Seminar Series, Annual GeoEngineering Society Year-End Distinguished Lecture Program and Banquet, University of California at Berkeley

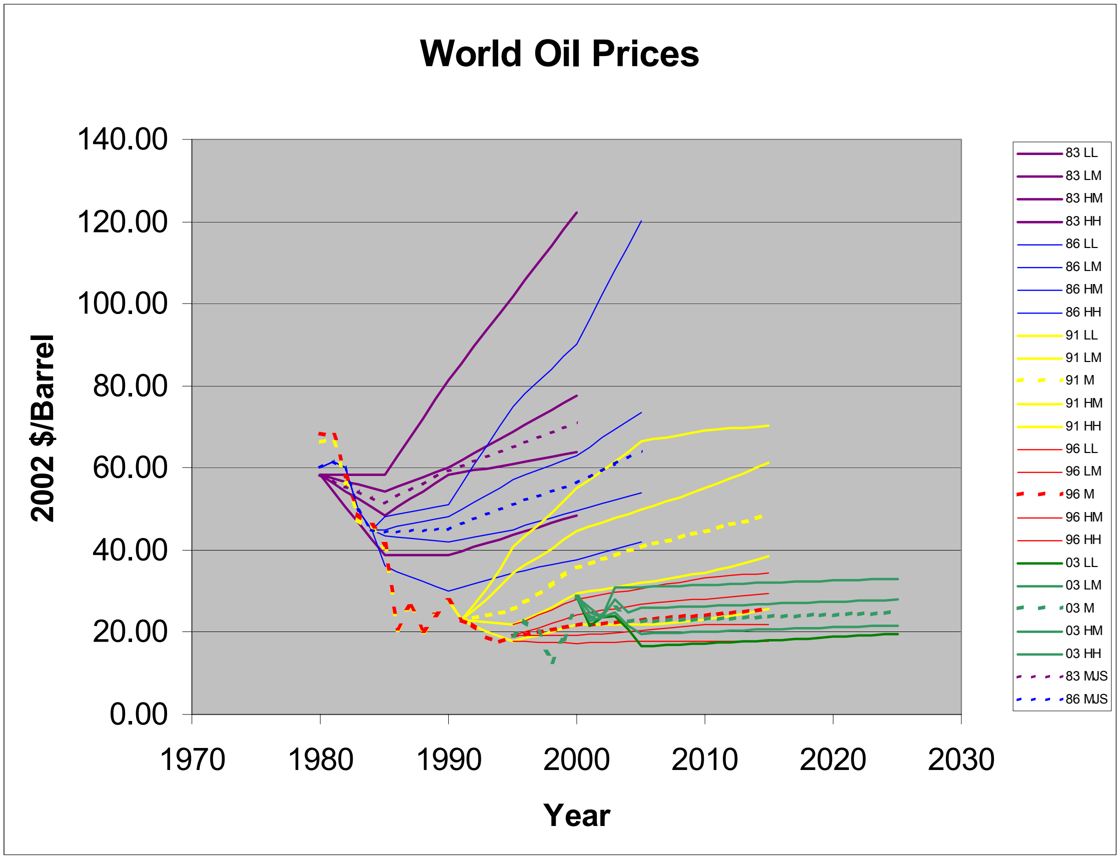


**Figure P-7: Council's World Oil Price Predictions**

is behaving correctly and to understand how the system and the plan to perform under that future.

This utility provides the principal means of validation. Rather than attempting to understand statistical distributions for each source of uncertainty in the relationship to other sources of uncertainty, an analyst can witness the final behaviors and see how they stand in relationship to each other. The Council's System Analysis Advisory Committee (SAAC) and the Council have reviewed these futures and found them to be reasonably representative of possible future behaviors.

With this overview of the decision making under uncertainty, this appendix starts the first section, the detailed description of the model's treatment of uncertainties.

# *Uncertainties*

This section consists of two main parts. The first part is an introduction to Stochastic Process Theory implemented in the regional model. There are six main discussions:

- Log normal distributions
- Geometric Brownian motion (GBM)
- GBM with mean reversion
- Simulating Values for Correlated Random Variables
- Principal factor decomposition
- Stochastic Adjustment
- Jumps

The regional model uses each of these techniques to represent the future behavior of sources of uncertainty. The discussion will identify how each technique captures both short-term variation and strategic uncertainty.

The second part of this section steps through each source of uncertainty and describes why that source of uncertainty is model the way that it is. The uncertainties include:

- Load requirements
- Gas price
- Hydrogeneration
- Electricity price
- Forced outage rates
- Aluminum price
- $CO_2$ tax
- Production tax credits
- Green tag value

It explains how each source of uncertainty uses the chosen stochastic process to achieve the desired behavior. It also documents data sources and provides a reference to the sample worksheet to provide a detailed description of how the formulas in the worksheet implement the desired stochastic behavior.

## Stochastic Process Theory

Lognormal distributions are a key characteristic of geometric Brownian motion (GBM) and GBM with mean reversion. The regional model uses lognormal distribution in the electricity price, fuel price, load requirements, and aluminum price processes. This discussion therefore starts with a review of the lognormal distribution and then describes the GBM and the GBM with mean reversion processes. Principal factor analysis technique does not rely per se on any of these, and the section will review this technique last.

## Lognormal Distribution

It might be useful to understand why the lognormal distribution finds such intensive use in the regional portfolio model and in other simulation and valuation models. There are three reasons the regional model uses lognormal distributions:

1. It solves problems we encounter with simpler distributions,
2. It has an nice intuitive rationale, and
3. It describes much data better than simpler (and sometimes more complex) distributions.

To understand these advantages, we start by examining the problems that a naïve application of simpler distributions might encounter.

If an inexperienced analyst with some background in statistics were to approach the challenge of modeling stochastic prices, he might try to use a simple distribution, such and the normal distribution. However, any unbounded, symmetric distribution, like the normal distribution, must produce negative numbers, as illustrated in Figure P-8. Negative prices, however, are bothersome and may cause some programs to fail in mysterious and unpredictable ways. One fix to this problem is to use an asymmetric, bounded distribution, such as the triangular distribution, to keep prices positive. Of course, the drawback to this approach is that because the distribution has both a lower and upper bound, the analyst must now provide some rationale for choosing the value of the upper price limit.

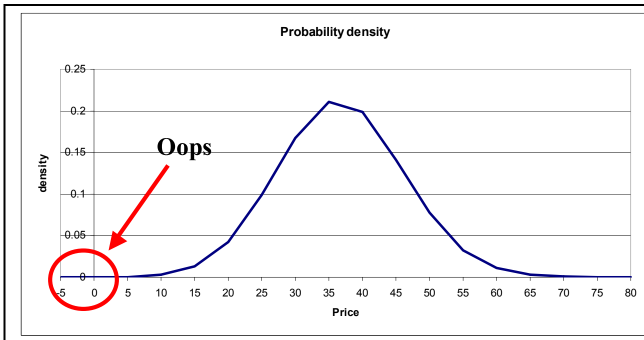


**Figure P-8: Symmetric Distribution**

The second problem the analyst might encounter would be difficulty in performing meaningful statistics on prices. There are several issues here.

First, prices for commodities typically are not symmetric. Because they are bounded below by zero, but are unbounded above in principle, they can be strongly skewed. This means that simple distributions, like the normal distribution, and statistical tests based on these distributions, do not work. For example, one can not say that 95 percent of the observations lie within of two standard deviations of the mean.

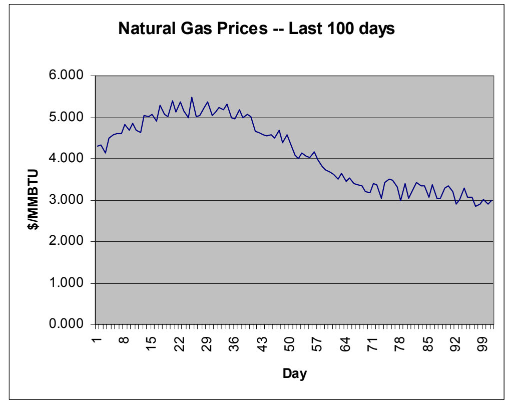


Figure P-9: Price Variation

Second, prices can drift in ways that mask the information in which an analyst might be interested. To illustrate this, suppose an analyst were interested in estimating the daily variation for natural gas price. Perhaps she is interested in estimating the likely change in natural gas price between today and tomorrow. Because she is interested in the change in daily price, it makes sense to use daily prices for the statistical sample, as opposed to hourly prices or weekly prices. To get a representative sample, she uses the last 100 days of natural gas price history, illustrated in Figure P-9. If she made the mistake of calculating the variation in prices, as measured by their standard deviation, without studying the data beforehand, she would compute the standard deviation to be about $0.83. The one standard deviation bound around the average price appears in Figure P-11. Clearly, this overestimates the daily price variation. The actual daily price variation is closer to the $0.14 that Figure P-10 illustrates. If she did discovered that price drift was distorting the estimate of price variation, she would need to develop a model of the underlying drift or seasonality to remove that influence.

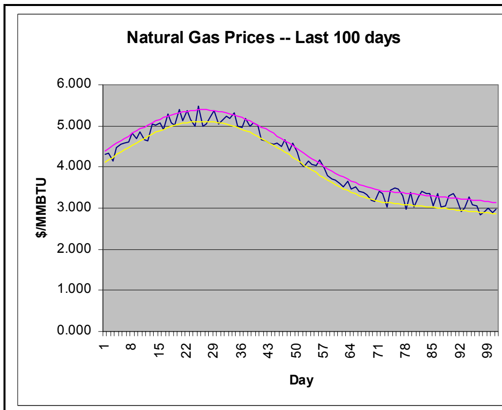


Figure P-10: Daily Price Uncertainty

Third, prices are often the wrong variable to study. Natural gas, for example, is a commodity traded by both hedgers and speculators. Both of these groups, but perhaps especially speculators, buy and sell natural gas to maximize profit. Now, initially it may appear that a $1.50 price increase of natural gas is equally attractive (or costly) irrespective of whether the underlying price of the gas is $3.00 or $4.50. The gross profit would be $1.50 times the quantity of gas. This ignores the fact, however, that an investor can buy more $3.00 gas than they can buy $4.50 gas. That is, what investors are interested in is the return on dollar invested: $p_t/p_{t-1}$, where $p_t$ is the price today and $p_{t-1}$ was the price yesterday.

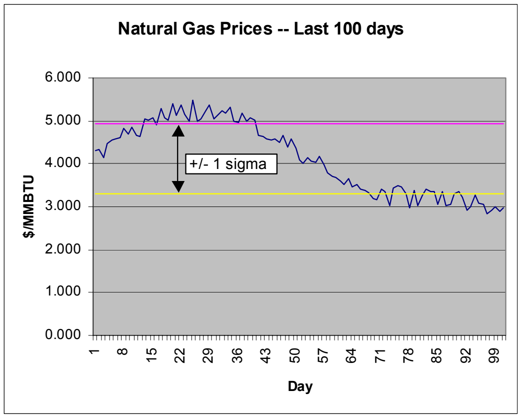


**Figure P-11: Standard Deviation of Price Data**

The same is true for other commodities and for financial investments. The return on the investment that matters, not the price. In fact, an analysis of prices for stocks and commodities show that returns, not prices, bump up and down symmetrically in the very short term (hourly or daily) as new information is forthcoming and they are traded. *Symmetry of returns* often explains a large portion of the *asymmetry of prices* described in the first paragraph.

Another advantage of using price returns instead of prices is that the second problem mentioned above disappears. That is, if the analyst uses daily price returns, she will obtain an estimate of daily price variation that more closely resembles that illustrated in Figure P-10.

Using returns, however, seems to give rise to yet another problem: calculating meaningful statistics on price return is tricky. Let us say that our analyst discovers that return on prices has about a normal distribution. It may be easy to calculate the mean and standard deviation of this distribution, but what do these numbers represent? To see the problem with interpreting these statistics, consider the following example. Suppose we have a simple sample of two observations, 50 percent price return and -50 percent price return. That is, on day two, the price increases 50 percent from that on day one; on day three, the price decreases 50 percent from that on day two. The naïve average of these two would be zero price return. In fact, however, we would have

$$1.5 \times 0.5 = .75$$

That is, our final price return would be -25 percent. It is unclear what the average of this distribution means and it is even less clear how to extract meaningful information out of the standard statistics of this distribution.

Consider now taking the log transformation of price return:

$$y_t = \ln(p_t / p_{t-1}), \text{sometimes also denoted } p_t / p_{t-1} \overset{\ln}{\mapsto} y_t \qquad (1)$$

This has the inverse transformation:

$$p_t / p_{t-1} = e^{y_t}, \text{sometimes also denoted } y_t \overset{e}{\mapsto} p_t / p_{t-1} \qquad (2)$$

The transformed variable $y_t$ has properties that solve the problems this section has raised and has some additional nice properties, as well. First, for small returns the logarithm of returns has a value close to that for the regular return:

$$\text{As } p_t \to p_{t-1}, \text{then } y_t \to p_t / p_{t-1} - 1$$

The sum and the average of the transformed returns have straightforward and useful interpretations. The sum of the transformed return is the total return over the period:

$$
\begin{aligned}
&\ln(p_2/p_1)+\ln(p_3/p_2)+\cdots+\ln(p_n/p_{n-1})\\
&=\ln(p_2)-\ln(p_1)+\ln(p_3)-\ln(p_2)+\cdots+\ln(p_n)-\ln(p_{n-1})\\
&=\ln(p_n)-\ln(p_1)\\
&=\ln(p_n/p_1)\overset{e}{\mapsto} p_n/p_1\text{, the return over the period}
\end{aligned}
$$

The average of the transformed return is the periodic growth rate, also called the geometric mean:

$$
\begin{aligned}
&\frac{1}{n}\left(\ln(p_2/p_1)+\ln(p_3/p_2)+\cdots+\ln(p_n/p_{n-1})\right)\\
&=\frac{1}{n}\ln(p_n/p_1)\\
&=\ln((p_n/p_1)^{\frac{1}{n}})\overset{e}{\mapsto}\sqrt[n]{p_n/p_1}\text{, the periodic growth rate}
\end{aligned}
$$

The reader will recognize this as the constant rate of growth that, if applied in each period, would increase or decrease the value in the first period to the value in the last period.

If the returns have normal distribution, the prices are said to have lognormal distribution. The lognormal distribution is bounded below by zero and unbounded above, as Figure P-12 illustrates. The population standard deviation of the transformed returns

$$
\sigma_y=\sqrt{\sum_{t=1}^{n}(y_t-\bar{y}_t)^2}=\sqrt{\frac{\sum_{t=1}^{n}y_t^{\,2}}{n}-\bar{y}_t^{\,2}} \qquad (3)
$$

and its inverse transformed value give uncertainty bounds consistent with those illustrated in Figure P-10. Standard quantitative finance texts typically refer the value of σ in Equation (3) (or the corresponding *sample* standard deviation) as the “volatility” of the price sequence. For small values, this volatility approaches the standard deviation of returns.

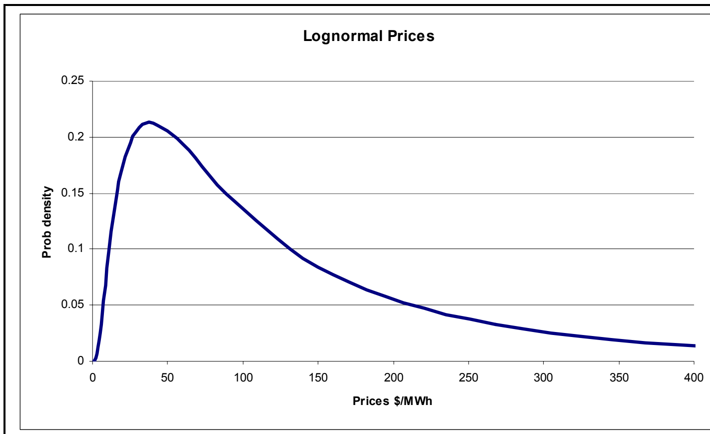


**Figure P-12: Lognormal Distribution**

Standard statistics for the transformed variables are relatively easy to compute and are readily available. For example if $\mu$ and $\sigma$ are the mean and standard deviation of a normally distributed variable, such as the transformed returns $y_t$,

$$\text{pdf } f(x) = \frac{1}{x\sigma\sqrt{2\pi}} e^{-(\ln x-\mu)^2/2\sigma^2}$$
$$E(x) = e^{\mu+\sigma^2/2}$$
$$\text{var}(x) = (e^{\sigma^2}-1)E^2(x) = (e^{\sigma^2}-1)e^{2\mu+\sigma^2}$$

where as usual, *E(x)* is the expectation of the lognormally distributed *x* and var*(x)* is the variance of *x*.

## Geometric Brownian Motion

The previous section made passing reference to the behavior of prices, bumped around by short-term purchases and sales of the commodity in the market. A standard quantitative representation of this process is Brownian motion. Brownian motion assumes that changes in location (or price) take place in discrete steps. At each step, displacement is determined by a sample from a normal distribution with constant means zero and constant standard deviation sigma.

The standard deviation of the distribution for the sum of these steps is a well-known formula. If there are T steps, the standard deviation is

$$\sqrt{\sigma_1^{\,2} + \sigma_2^{\,2} + \cdots + \sigma_T^{\,2}}$$
$$= \sqrt{T\sigma^2} = \sigma\sqrt{T}$$

The standard deviation grows as the square root of the number of steps, as illustrated in Figure P-13.

The previous section explained that the distribution of transformed returns, $y_t$, is normal for many investments and commodity prices. If the transformed returns follow the kind of process described above, the corresponding prices are said to follow geometric Brownian motion (GBM). At each step, prices have lognormal distribution.

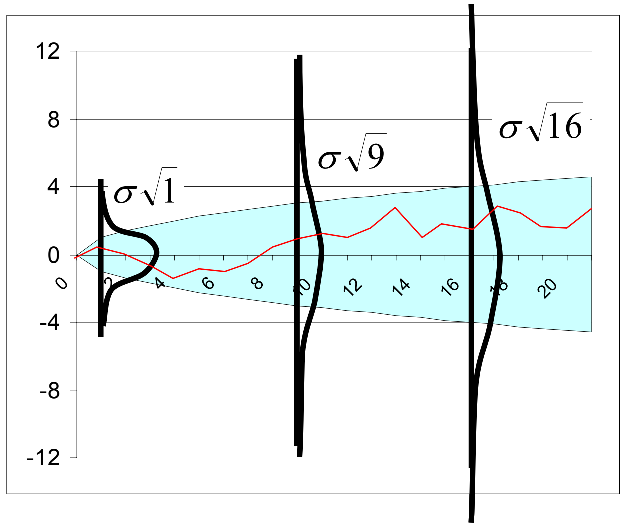


**Figure P-13: Uncertainty Growth of GBM Process**

## GBM with Mean Reversion

Some commodity prices, instead of drifting away from their starting point, instead tend to return to some equilibrium level. This appendix and **Appendix L** describe how fundamental models will produce long-term equilibrium prices that equal long-run marginal costs for new capacity. The long-term equilibrium price represents the level to which prices trend whenever substantial excursions occur. Away from the equilibrium price, long-term supply and demand do not balance, and fundamental economic forces contrive to rebalance them.

There are several price models for a geometric Brownian motion with mean reversion. The regional model uses the following to represent aluminum prices.[9]

$$dp_t = a(b - p_t)dt + \sigma p_t dz$$

where

$p_t$ is stochastic variable in question

$dp_t$ is the change in $p_t$ from the previous step

$dz$ is a drawn from a N(0,1) process

$dt$ is the step size, which has value 1 for discrete processes

$a$ is constant which controls the rate of reversion

$b$ is the equilibrium level

$\sigma$ is the standard deviation of the log transformed process

The process is identical to an Ito process for a lognormally distributed random variable, but with a drift term that incorporates mean reversion. As prices depart from the equilibrium price $b$, the term $(b - p_t)$ becomes larger and forces the price back to equilibrium. The strength of the reversion is determined by the constant $a$. The first-order autocorrelation of price provides an estimate of the value of the constant $a$. If the

[9] See, for example, Hull, John C., ***Options, Futures, and Other Derivatives***, 3rd Ed., copyright 1997, Prentice-Hall, Upper Saddle River, NJ., ISBN 0-13-186479-3, page 422

constant *a* has value zero, there is no mean reversion and the price process resembles that of standard GBM. Price will drift in away from the starting point with increasing probability. This corresponds to zero autocorrelation. If the constant *a* is 1.0, the price fluctuates around the equilibrium price and does not drift.

The section "Aluminum Price," beginning on page P-86, describes how this price process represents future aluminum prices. That section includes an explanation of how Excel formulas implement the price process.

There are many other price process models. Some of the more popular models employ jump diffusion and jump diffusion coupled with mean reversion. For the purposes of the regional model, however, these models are excessive. Studies of natural gas and electricity prices suggest that simple geometric Brownian motion does a good job of describing those prices.

## Simulating Values for Correlated Random Variables

For each future, the model must generate a large number of correlated values for the stochastic variables. This section describes one standard technique for doing so. The next section uses a simplification of this technique to obtain a more economical representation of strongly correlated values.

Suppose that we have a vector $\boldsymbol{\varepsilon}$ of m values $\varepsilon_j$ which have some covariance structure Σ. Recall that the covariance matrix is constructed by taking the expectation of the outer product[10] of the vector of deviations from the mean vector **u**:

$$\Sigma = E((\varepsilon - \mathbf{u})(\varepsilon - \mathbf{u})') \quad (5)$$

Because the covariance matrix is a positive definite, symmetric matrix of real numbers, it has representation as the product of its Cholesky factors $\Sigma = TT'$, where T is a lower triangular matrix with zeros in the upper right corner.[11]

Now, take another m-vector η composed of independent variables with zero mean and unit variance. The covariance matrix of the vector η will just be the m x m identity matrix. If we construct the vector $T\eta$, we discover its covariance matrix is

$$\begin{aligned} E(T\eta\eta'T') &= TE(\eta\eta')T' \\ &= TIT' = TT' = \Sigma \qquad (6) \end{aligned}$$

Thus, the vector $T\eta$ has the requisite covariance structure. If we were working with the correlation structure instead of the covariance structure, the conversion is easy. The

[10] For our purposes, an outer product is the matrix product of a (column) vector right-multiplied by its transpose. This multiplication creates a matrix instead of a scalar, which inner products produce.

[11] See, for example, Burden and Faires, ***Numerical Analysis***, 4th ed., ISBN 0-53491-585-X, Corollary 6.26 and Algorithm 6.6, page 370.

covariance matrix transforms into the correlation matrix by a simple operation using the diagonal matrix of standard deviations, *D*:

$$\Sigma = DRD \qquad (7)$$

For an example of how to generate correlated values, consider the two-vector **ε**, where the variables both have zero mean and unit variance. The covariance matrix is the same as the correlation matrix:

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix}$$

By the existence of the Cholesky decomposition, there are variables $t_{11}$, $t_{12}$, and $t_{21}$, such that

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix} = \begin{bmatrix} t_{11} & 0 \\ t_{12} & t_{22} \end{bmatrix} \begin{bmatrix} t_{11} & t_{12} \\ 0 & t_{22} \end{bmatrix} = \begin{bmatrix} t_{11}{}^2 & t_{11}t_{12} \\ t_{11}t_{12} & t_{12}{}^2 + t_{22}{}^2 \end{bmatrix}$$

Because the Cholesky matrix is triangular, we can find the values for the entries in the Cholesky matrices by successive substitution:

$$\begin{aligned} t_{11}{}^2 &= 1 \\ t_{11}t_{12} &= \rho \\ t_{12}{}^2 + t_{22}{}^2 &= 1 \end{aligned}$$

so

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ \rho & (1-\rho^2)^{1/2} \end{bmatrix} \begin{bmatrix} 1 & \rho \\ 0 & (1-\rho^2)^{1/2} \end{bmatrix}$$

which means

$$\varepsilon = \begin{bmatrix} 1 & 0 \\ \rho & (1-\rho^2)^{1/2} \end{bmatrix} \eta \qquad (8)$$

Of course, this technique applies to vectors of arbitrary dimension. Note, however, the number of non-zero entries in *T* increases as $(m^2+m)/2$, as do the number of multiplications and additions, roughly, to create a sample vector. When m is large, the computation burden can increase dramatically. For this reason, practitioners have developed various numerical efficiencies to reduce the computation burden. One of these efficiencies is the topic of the next section.

## Principal Factor Decomposition

Principal factor analysis is a general statistical technique for capturing complex statistical behavior with a small number of random variables. In the regional model, principal factor analysis simplifies the representation of strategic uncertainties that have strong chronological correlation, i.e. follow some underlying path over time.

Natural gas price has such a strategic uncertainty, as well as short-term variation due to weather effects and regional economics. For example, consider the price path illustrated by the dotted line in Figure P-14.[12] One way to model the path is by adding up several simpler paths, each of which is a draw from a separate statistical population of similar, simple paths. The advantage of this approach is the resulting sum will look like a path, i.e., the entries will be strongly correlated, and it gives rise to a great number of possible such paths. This section explains how to perform the construction.

Before the reader attempts to work their way through this section, which is among the more mathematically challenging, they should be aware of its purpose. The regional model implements an adaptation of the concepts presented here. While these concepts have rigorous application to statistical problems with abundant and representative data, the application in the regional model is more art than science. While this is consistent with the spirit of validation articulated on page P-17, it means that understanding the mathematics is not essential to grasping the basic technique of adding up constituents "sub-paths" point-wise. This section merely provides the basis for the technique, to assure the reader that it is neither arbitrary nor original.

Before tackling the construction of paths for future prices under strategic uncertainty, we begin with a simpler construction, one for which data exists and that may be more familiar to some readers. Suppose that, instead of representing strategic natural gas price uncertainty, Figure P-14 represented represent possible *forward or futures* prices for natural gas. Suppose further, that our objective were to estimate *tomorrow's* forward curve for natural gas, that is, tomorrow's prices for future delivery of natural gas in each year through 2024. There is data about the variation in the forward curves for natural gas price, in principle, because each day traders buy and sell gas forward. Every day, for example, traders buy and sell 2006 gas, and it is possible to get statistics about how that price varies. Others statistics of interest that we can obtain is how the price of 2006 gas price correlates with that of 2005, 2007, and all other years.

[12] Figure P-14 illustrates the ranges of natural gas prices that the Council adopted for the plan. The middle, solid line is the median price forecast; there is equal probability that annual prices will lie above and below this line.

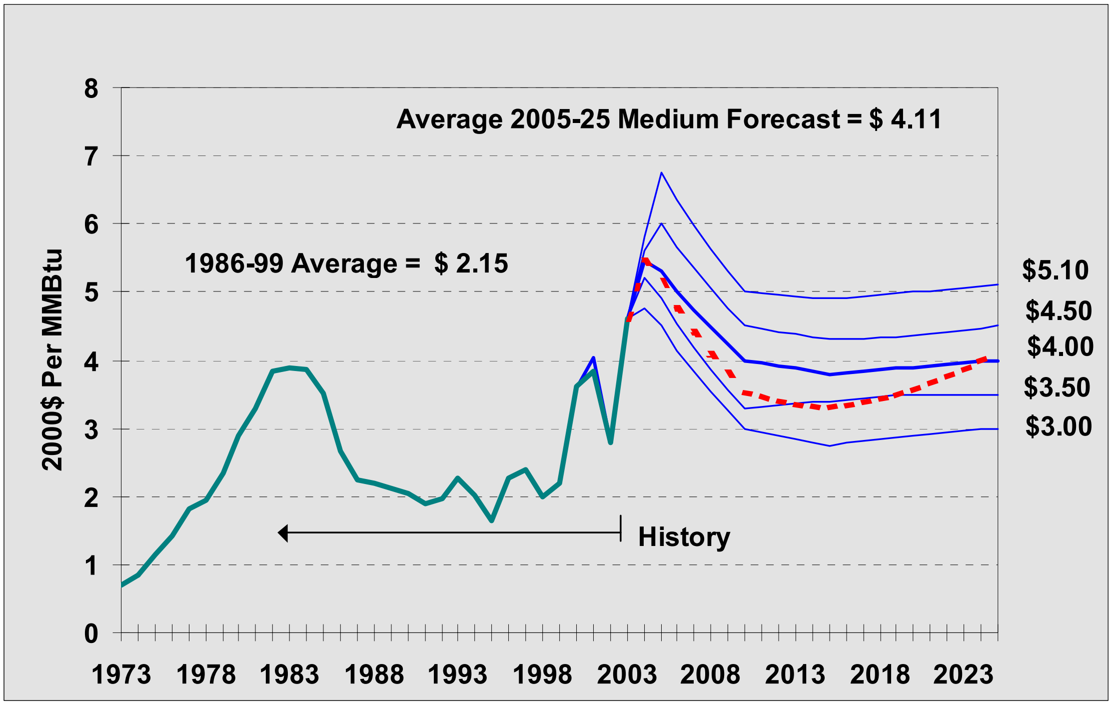


Figure P-14: Possible Natural Gas Prices

For this purpose, the medium forecast of natural gas prices in Figure P-14 will play the role of today's forward curve. The higher and lower price forecasts will represent the typical daily variation in the forward curve. (We will not use the higher and lower price forecasts directly in this example, so we do not need to be precise in how we think about them or their magnitude.)

The dotted line in Figure P-14 will play the role of one possible forward curve that may materialize tomorrow. We want to be able to generate many such forward curves, say, because we are valuing a portfolio of natural gas forward positions and want to understand how much variation and risk there may be in holding that portfolio overnight.

Recall from the discussion of "Lognormal Distribution," beginning on page P-20, that it is convenient, for all the reasons discussed in that section, to use transformed price returns. We will do that, but the approach will look different from the discussion in that section. Specifically, in that section, the price returns represented prices from successive periods. The section "Geometric Brownian Motion" described paths that result when these transformed returns stem from independent, uniform "innovations."[13] In fact, we are not going to make any such assumptions about how prices in 2006 relate to those in 2005 or 2007. We may have information that a large supply of natural gas is coming on-line in 2006, for example, so in a sense the 2006 product is distinct from those in 2005

[13] By innovation, we mean small, random shocks. These are generated by drawing a value from a random variable.

and 2007. Instead, for each year's price, we represent its covariance with any other year using principal factor analysis, and the only innovation we are interested in is the one-step change between today and tomorrow. (Remember, we are simulating tomorrow's forward curve.) If we do this for each forward year, we get a new curve.

We start by taking the logarithm of the price for each year $j$, $j$=1 to m, of today's forward curve. The prices and transformed prices appear in equations (1). Denote this transformed price by $\ln(\boldsymbol{p}_{j,0})$. Denote the corresponding transformed price for *tomorrow* by $\ln(\boldsymbol{p}_{j,1})$. The innovations $\varepsilon_j$ are drawn from a the distribution of the transformed returns $\ln(\boldsymbol{p}_{j,t+1}/\boldsymbol{p}_{j,t})$ obtained from historical data for that forward year. A given draw then gives us the means of estimating a possible prices for tomorrow's forward curve:

$$\begin{aligned} &\ln(p_{j,1}) = \ln(p_{j,0}) + \varepsilon_j, \text{ where} \qquad (9) \\ &\varepsilon_j \approx \ln(p_{j,t+1}/p_{j,t}) \end{aligned}$$

The second line merely says that the innovations are distributed like the transformed daily price returns for year $j$.

The previous section provides a technique for simulating this vector of innovations. We can construct the covariance matrix from historical data, find the Cholesky decomposition, and use a higher-dimensional version of equation (8) to produce the samples. If natural gas prices behave as many commodity prices do, the innovations will be roughly normally distributed, so the vector η in equation (8) will be drawn from a normal distribution.

When practitioners applied these techniques to very large vectors, however, they discovered that these calculations could become burdensome. The computations increase roughly as the number of non-zero elements, $(m^2+m)/2$, in the Cholesky factor. They discovered that, by using principal factor analysis, they could substantially reduce that computational burden, especially when the entries in the vector of prices were strongly correlated.

Principle factor analysis is based on the fact that any symmetric matrix, such as any covariance matrix, has a "spectral decomposition"

$$\mathbf{A} = \lambda_1 \mathbf{e}_1 \mathbf{e'}_1 + \lambda_2 \mathbf{e}_2 \mathbf{e'}_2 + \cdots + \lambda_m \mathbf{e}_m \mathbf{e'}_m \qquad (10)$$

where

$\mathbf{A}$ is a $(m \times m)$ symmetric matrix

$\lambda_i$ is the $i$th eigenvalue

$\mathbf{e}_i$ is the $i$th normalized eigenvector $(m \times 1)$

$\mathbf{e'}_i$ is the transpose of $\mathbf{e}_i$

If there are strong correlations among entries of the random vector, several of the eigenvalues tend to be much larger than the rest. The eigenvectors are principal patterns of correlated variation in entries and these give rise to the paths to which this section has referred. If the terms in equation (10) are sorted with respect to magnitude of their eigenvalues (they will all be positive), we can represent the covariance matrix as the sum of two matrices, one associated with the first *k* dominant eigenvalues and the second associated with the remaining eigenvalues. Because these two terms are also symmetric matrices, they both have Cholesky terms:

$$\begin{aligned}
&\Sigma = \mathrm{LL'} + \mathrm{SS'} \\
&\text{where} \\
&\mathrm{L \text{ is }} m \times k \\
&\mathrm{S \text{ is }} m \times (m-k)
\end{aligned}$$

The S matrix should be nearly diagonal and if we replace it by a diagonal matrix, we obtain an equation for creating the innovations that corresponds to equation (8):

$$\begin{aligned}
&\mathbf{X} - \boldsymbol{\mu} = \mathbf{L}\mathrm{f} + \boldsymbol{\varepsilon} \qquad\qquad (11) \\
&\text{where} \\
&\mathbf{X} \text{ is the } k \text{ - vector of random variables} \\
&\boldsymbol{\mu} \text{ is their } k \text{ - vector of means} \\
&\mathbf{L} \text{ is the } (k \times m) \\
&\quad \text{matrix of } k \text{ - eigenvectors} \\
&\mathrm{f} \text{ is an } m \text{ - vector of independent random variables} \\
&\boldsymbol{\varepsilon} \text{ is a } k \text{ - vector of independent random "specific factors"}
\end{aligned}$$

The entries in the m-vector f may be taken to be distributed N(0,1); the specific factors may also be taken as independent, normally distributed with mean zero, but the variance of each is determined by the residual variance necessary to match that of **X-μ**. Efficiencies arise when *m* is much less than *k*.

In Figure P-14, the possible forward curve is the weighted sum of the following three eigenvectors:

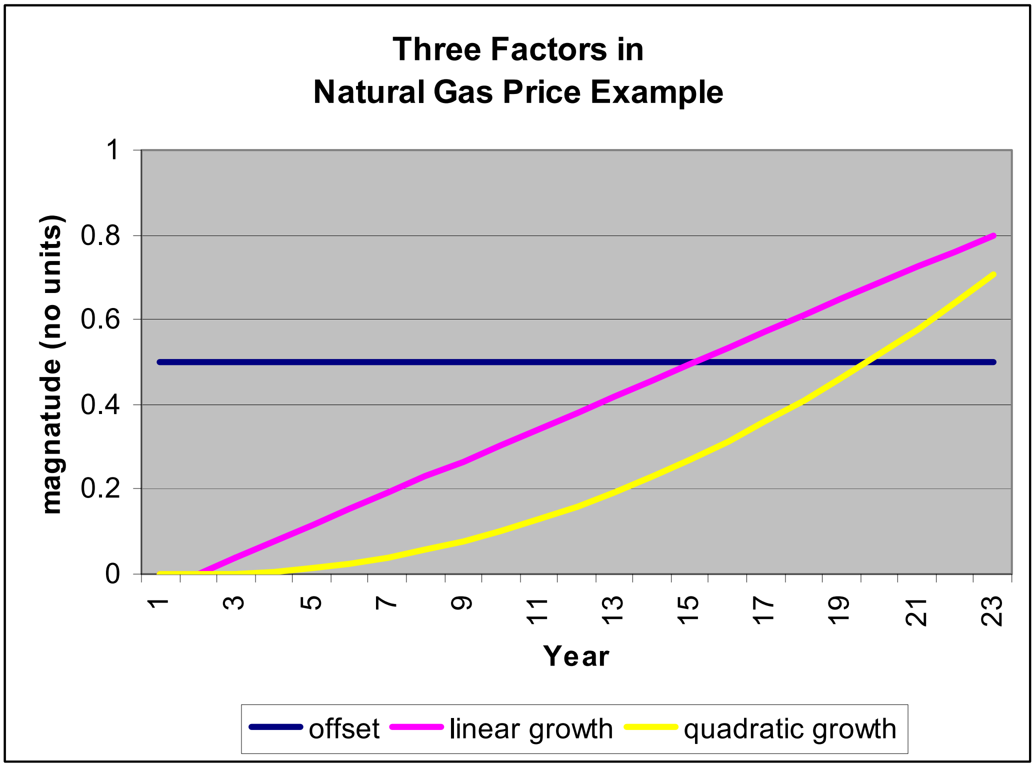


**Figure P-15: Constituent Eigenvectors**

For the possible (dotted line) forward curve in Figure P-14, the offset, linear growth, and quadratic growth eigenvectors, of "sub-paths," are weighted by 0.00, -0.75, and 0.90, respectively. These sub-paths are then added to the transformed returns, as in equation (9), and transformed back to prices using the standard exponential transformation described on page P-22. Figure P-16 illustrates the steps.

Slightly different weightings provide dramatically different paths. For example, the weighting (0,1.25, -1.2) gives rise to the path illustrated in Figure P-17. The weighting (-1.4, 1.25, -1.2) generates the curve in Figure P-18.

| P0 | ln(P0) | offset | linear | quadratic | sum (e) | ln(P0)+e | P1= exp(ln(P0)+e |
|---|---|---|---|---|---|---|---|
| 4.62 | 1.53 | 0.00 | 0.00 | 0.00 | 0.00 | 1.53 | 4.62 |
| 5.45 | 1.70 | 0.00 | 0.00 | 0.00 | 0.00 | 1.70 | 5.47 |
| 5.30 | 1.67 | 0.00 | -0.03 | 0.00 | -0.03 | 1.64 | 5.16 |
| 5.01 | 1.61 | 0.00 | -0.06 | 0.01 | -0.05 | 1.56 | 4.76 |
| 4.74 | 1.56 | 0.00 | -0.09 | 0.01 | -0.08 | 1.48 | 4.39 |
| 4.48 | 1.50 | 0.00 | -0.11 | 0.02 | -0.09 | 1.41 | 4.10 |
| 4.23 | 1.44 | 0.00 | -0.14 | 0.04 | -0.10 | 1.34 | 3.82 |
| 4.00 | 1.39 | 0.00 | -0.17 | 0.05 | -0.12 | 1.27 | 3.56 |
| 3.96 | 1.38 | 0.00 | -0.20 | 0.07 | -0.13 | 1.25 | 3.49 |
| 3.92 | 1.37 | 0.00 | -0.23 | 0.09 | -0.14 | 1.23 | 3.42 |
| 3.88 | 1.36 | 0.00 | -0.26 | 0.12 | -0.14 | 1.22 | 3.39 |
| 3.84 | 1.35 | 0.00 | -0.29 | 0.14 | -0.15 | 1.20 | 3.32 |
| 3.80 | 1.34 | 0.00 | -0.31 | 0.17 | -0.14 | 1.20 | 3.32 |
| 3.82 | 1.34 | 0.00 | -0.34 | 0.21 | -0.13 | 1.21 | 3.35 |
| 3.84 | 1.35 | 0.00 | -0.37 | 0.24 | -0.13 | 1.22 | 3.39 |
| 3.86 | 1.35 | 0.00 | -0.40 | 0.28 | -0.12 | 1.23 | 3.42 |
| 3.88 | 1.36 | 0.00 | -0.43 | 0.32 | -0.11 | 1.25 | 3.49 |
| 3.90 | 1.36 | 0.00 | -0.46 | 0.37 | -0.09 | 1.27 | 3.56 |
| 3.92 | 1.37 | 0.00 | -0.49 | 0.42 | -0.07 | 1.30 | 3.67 |
| 3.94 | 1.37 | 0.00 | -0.51 | 0.47 | -0.04 | 1.33 | 3.78 |
| 3.96 | 1.38 | 0.00 | -0.54 | 0.52 | -0.02 | 1.36 | 3.90 |
| 3.98 | 1.38 | 0.00 | -0.57 | 0.58 | 0.01 | 1.39 | 4.01 |
| 4.00 | 1.39 | 0.00 | -0.60 | 0.64 | 0.04 | 1.43 | 4.18 |

**Figure P-16: Steps in the Calculation**

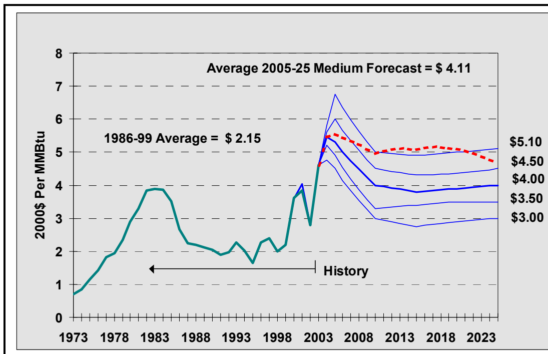


**Figure P-17: Path with (0,1.25, -1.2) Weighting**

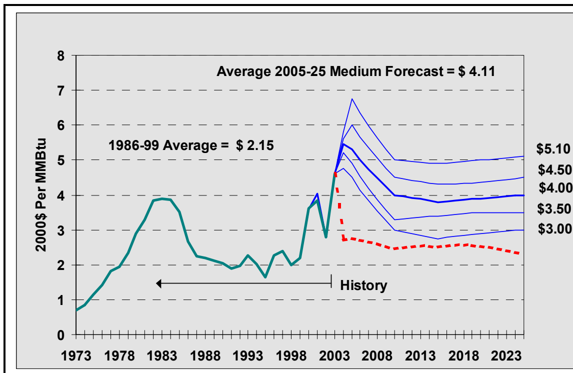


**Figure P-18: Path with (-1.4, 1.25, -1.2) Weighting**

Returning to the original challenge of creating new paths for future prices and loads, it would be natural to attempt construction of future paths based on historical data. It turns out, though, that those kinds of patterns generally did not garner credibility with experts. They usually failed to capture the experts' scale of uncertainty. Effectively the curve weighting and parameters were calibrated to the experts' expectations. This is in keeping with the spirit of strategic decision analysis articulated on page P-17, however, which recognizes the subjective nature of characterizing complex and unpredictable behaviors.

Three factors, like those illustrated in Figure P-15, appear to be sufficient to capture the kind of underlying path behaviors that experts wished to see. Of course, these paths do not suffice to produce all of the kinds of necessary behavior. There is short-term (period) variation, as we might expect to see with weather differences. Prices and requirements possess short-term correlations, within the modeling period, and these require attention. There are also jumps that reflect excursions from long-term supply and demand equilibrium or other economic disruption. The construction of the jumps is the subject of the next section.

The example of natural gas price simulation in the workbook L24DW02-f06-P.xls provide a good example of how the regional model treats the factors. This takes place in rows {56 to 62}. As shown in Figure P-19, the value for the period 7 in {X62} is a sum of three products. The first product is the weighting for the linear growth {$S$56}, times the random number in {$R$56}, times the value of the factor in {$W$57}. The random

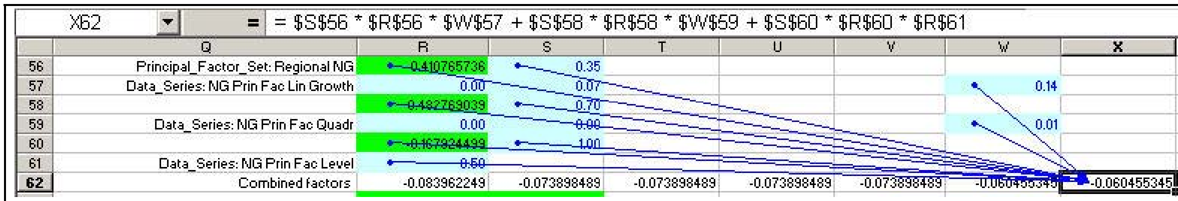


**Figure P-19: Adding the Principal Factors**

number plays the role of an entry of η in equation (8) or of **f** in equation (11). The distribution of the random number will depend on the simulated uncertainty. The value of the linear factor does *not* increase smoothly over the 80 periods, from 0.0 to 1.33. Instead, because the Olivia model[14] that created this workbook used annual values, the values only change once each four columns, and the logic points back to the last data value for the factor.

The remaining two terms in the sum {X62} add the quadratic and offset factors. Because the offset factor does not change across periods, the formulas in row {62} all point to the offset factor value in cell {R61}.

This is not the last step in creating the behavior for natural gas price. Other influences, such as jumps, add to the combined factor, and the worksheet applies the necessary inverse transformation to the sum. The next two sections discuss specific factors and jumps. The subsequent section describes the stochastic adjustment, and the section following that one shows the final inverse transformation.

## Specific Factors

Specific Factors arise in equation (11) as a means to capturing variance not accounted for by the principal factors. They are "specific" in the sense that they describe only the remaining variance for a stochastic vector's entries.

[14] Olivia is a Council application that creates Excel worksheet portfolio models. Appendix L describes Olivia.

In the regional model, specific factors are typically describing seasonal variation, which can be greater at certain times of the year. For example, loads tend to have greater uncertainty during the winter and summer, so the model adds independent variance to those seasons. Figure P-20 shows the crystal ball dialog box that specifies the distribution of the random variable in cell {AQ 124}. This is a normal distribution with mean zero and a standard deviation of five percent. As described in the section "lognormal distribution," this small standard deviation will correspond to roughly five percent standard deviation change in the final quarterly loads

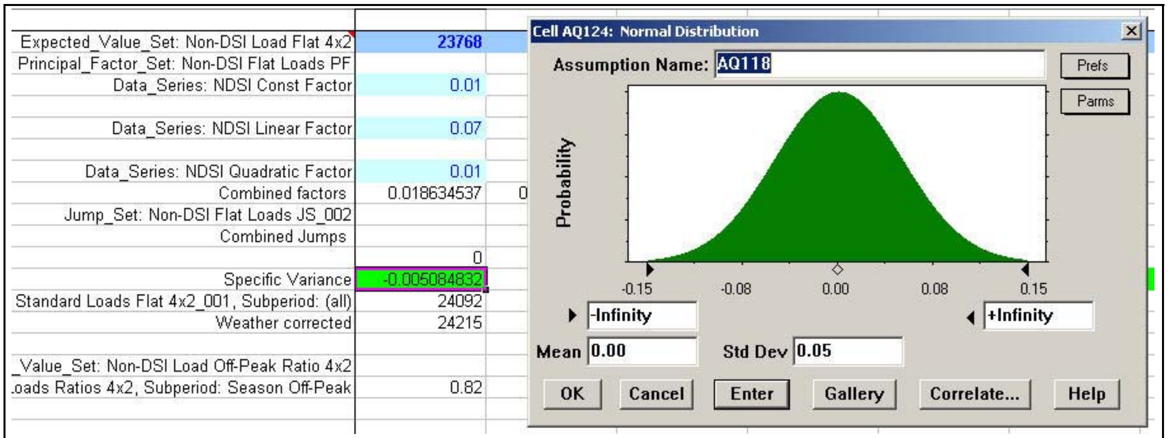


**Figure P-20: Assumption Cell**

## Jumps

Excursions occur in prices and loads for several reasons, in particular because of disequilibrium in long-term supply and demand. Gas and electricity prices, as we have seen in the last few years, can depart significantly from their equilibrium values when capacity shortages occur. It typically takes a year or two for new capacity to come on-line. Load excursions will occur due to business cycles or large economic displacements. It is important to have this kind of behavior in the regional model because large and sudden changes, which can last a significant time, are key sources of uncertainty and risk. These changes, moreover, may stem from activities and prices outside the region and may therefore be uncorrelated with local events.

One of the shortcomings of the principal factor approach to simulating price paths is that it does not easily or naturally accommodate excursions that begin at random times and last for a random number of periods. Rather that forcing the principle factor metaphor, the regional model represents these excursions with a different, simpler technique.

In the regional model, jumps can begin at random times and have random magnitude and duration. There is logic to model the "recovery" from excursions and to constrain when jumps can take place.

Figure P-21, which shows the wholesale electricity price[15] in row {102} of our sample workbook L24DW02-f06.xls, illustrates a typical jump with recovery. The first jump, illustrated by the heavy line, and the subsequent recovery have an obvious impact on the electricity price, illustrated by the light line. In addition, a second jump begins in the 79th period and lasts the remaining two periods of the study.

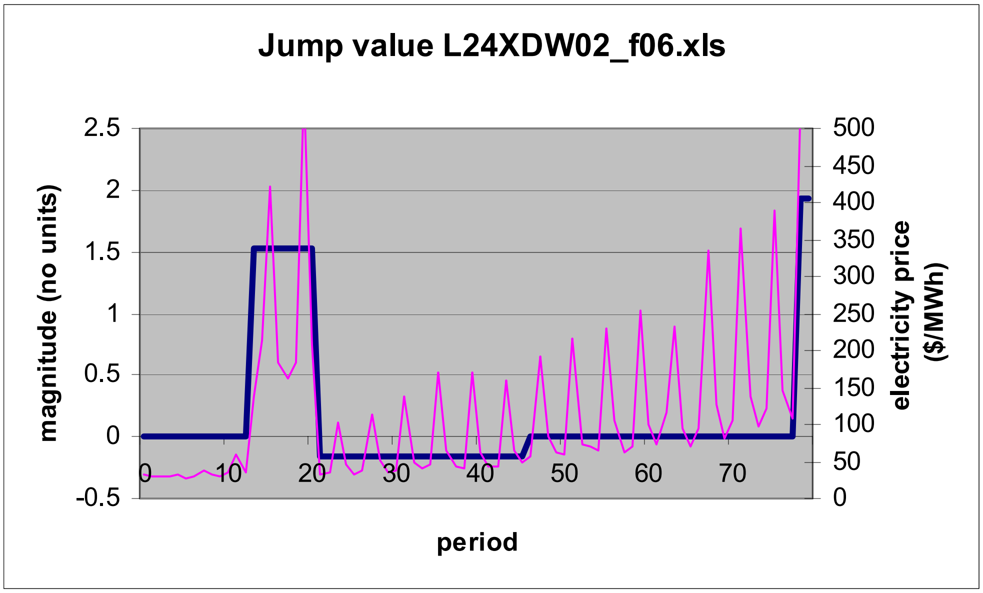


**Figure P-21: Typical Jump with Recovery**

The worksheet logic that produces the jump pattern appears in rows {99} through {102}. In principle, there can be as many jumps as the user desires. For this two-jump system, we first have the following Crystal Ball assumption cell values:

| | R | S | T |
|---|---|---|---|
| 99 | 13.74923 | 1.534261 | 10.59427 |
| 100 | 32.05555 | 1.935131 | 8.386783 |

where R, S, and T are the wait, size, and duration of the jump, respectively. The values for the wait and duration of a jump specify the number periods that must pass before a jump can begin and end, respectively. For proportional jumps, the model ignores the last parameter, because the size of the jump determines its duration. This particular example uses proportional jumps.

Then the formulas in the row {101} calculate intermediate values, which specify the periods in which events occur.

[15] This is the flat market price before any resource response. Resource responsive price modeling is the subject of Appendix L. "Flat" market prices are average prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

| | | | |
|---|---|---|---|
| **R101** | =$R$99 | wait_1 | start time of jump 1 |
| **S101** | =R101+ IF($S$99= 0,0,12/$S$99) | wait_1+ 12/size_1 | end time of jump 1 |
| **T101** | =$S$99 | size_1 | size_log xfr jump 1 |
| **U101** | =S101 | end time of jump 1 | start time of recovery 1 |
| **V101** | =U101+ S101*EXP(T101) | end time of jump 1 + duration recovery 1 | end time of recovery 1 |
| **W101** | =-T101/10 | -size_1/10 | size_log xfr recovery 1 |
| **X101** | =V101+ $R$100 | end time of recovery 1+ wait_2 | start time of jump 2 |
| **Y101** | =X101+ IF($S$100= 0,0,12/$S$100) | wait_2 + 12/size_2 | end time of jump 2 |
| **Z101** | =$S$100 | size_2 | size_log xfr jump 2 |
| **AA101** | =Y101 | end time of jump 2 | start time of recovery 2 |
| **AB101** | =AA101+ Y101*EXP(Z101) | end time of jump 2 + duration recovery 2 | end time of recovery 2 |
| **AC101** | =-Z101/10 | -size_2/10 | size_log xfr recovery 2 |

**Figure P-22: Intermediate Jump Calculations**

The first six columns, {R101 through W101}, calculate parameters for the first jump; those the next six columns pertain to the second jump. Note that the formulas for the first jump are almost identical to those for the second. If the user specified additional jumps, there would be six additional columns in that row for each additional jump.

The size and duration of the jump recovery are proportional to the inverse of the size of the jump. The scaling factors of 10 and 12 in columns {S, W, Y, and AC} control the sizes. The size of these factors produce "realistic" behavior, i.e., behavior that conformed to expectations about the future. Originally, the size of the duration and jump assured that the price or load adjustment, after appropriate inverse transformation

$$y_t \overset{e}{\mapsto} p_t / p_{t-1}$$

would average to 1.0. The intent was to create prices that averaged out to the long-term equilibrium value over time. This approach, however, produced recoveries that were much too large and lasted too long. The Council therefore abandoned it. Part of the rationale in moving away from an adjustment that averaged to 1.0 was some disbelief that there was justification for prices returning to a fixed long-term price. Equilibrium prices, after all, can change as underlying economics change.

Row {102} interprets the values in row {101} based on the period number in row {46} and produces the final jumps:

```
R102 = IF(AND(R$46>$R101,R$46<=$S101),$T101,0)+          jump_1
       IF(AND(R$46>$U101,R$46<=$V101),$W101,0)+          recovery_1
       IF(AND(R$46>$X101,R$46<=$Y101),$Z101,0)+          jump_2
       IF(AND(R$46>$AA101,R$46<=$AB101),$AC101,0)        recovery_2

S102 identical, except S$46 instead of R$46
T102 identical, except T$46 instead of R$46
```

Row {102} contains the values that must then undergo inverse transformation. This final transformation is the subject of the next section.

$CO_2$ and emission taxes exhibit a special kind of jump behavior not shared by loads and prices. There is only one jump, but its value can change on in particular periods. When the Council queried experts about the likelihood of carbon tax legislation, the experts agreed that any changes would probably occur with a change in the federal administration. Therefore, emission taxes can arise only in the year of a presidential campaign (2008, 2012, etc.). These are step functions of uncertain size and timing, otherwise. Any jump remains in place through the end of the study. The section on $CO_2$ tax uncertainty further describes this behavior.

## Stochastic Adjustment

Prices in the model derive from the Council's assumptions for long-term equilibrium prices[16]. For reasons discussed in Chapter 6, these equilibrium prices can be associated with the median price because there is equal probability of being above and below the median price. Some users may prefer, however, for the long-term equilibrium prices to match the price distribution's ***mean***. Because prices in the regional model use a lognormal distribution, however, the mean price is *higher* than the median price.

To accommodate this situation, the model can apply a "stochastic adjustment" to the benchmark price. This adjustment, a number between zero and one, is chosen so that the distributions mean price matches the benchmark price. An example of a stochastic adjustment for on peak wholesale electricity market prices appears in the second row of Figure P-23.

| | Series: Market Prices Independent Term_005 | | | | |
|---|---|---|---|---|---|
| Expected_Value_Set: Market Exp Price On-Peak 4x2 | 32.29 | 33.04 | 32.99 | 32.33 | 32.66 |
| Stochastic_Adjust_Set: Stoch Adj On-Peak 4x2 | 0.87 | 0.73 | 0.78 | 0.76 | 0.85 |
| Principal_Factor_Set: Reg Mkt Prc | -0.02037443 | 1.00 | | | |
| Data_Series: Mkt Prin Fac Level | 0.50 | | | | |
| | 0.007267999 | 1.00 | | | |
| Data_Series: Mkt Prin Fac Lin Growth | 0.00 | 0.07 | | | |
| Combined factors | -0.010187215 | -0.009678455 | -0.009678455 | -0.009678455 | -0.009678455 |
| Jump_Set: Elec Mkt_002 | 8.770426174 | 0.072691876 | 8.899814829 | | |
| | 16.07130502 | 0.100080134 | 11.46780741 | | |
| Combined Jumps | 8.770426174 | 173.850772 | 0.072691876 | 173.850772 | 220.5905142 |
| | 0 | 0 | 0 | 0 | 0 |

**Figure P-23: Stochastic Adjustment**

Each period typically requires a separate stochastic adjustment. Appendix L describes a utility, the macro subTarget, which automates the process for finding values for the stochastic adjustment.

## Combinations of Principal Factors, Specific Factors, and Jumps

The preceding sections describe how the model represents stochastic behavior using combinations of principal factors, specific factors, and jumps. It is easiest, however, to model these elements with simple symmetric or unbounded distributions. The inverse lognormal transformation then guarantees physical values that have positive value and behavior that is more realistic.

[16] Because the median and the mean both described the final distribution of prices after any adjustment, we refer to the starting place as the "benchmark price." The benchmark price is typically the long-term equilibrium price.

In the example of natural gas price from the sample workbook, the model combines these influences in row {68}. For example, the formula in column {R} is

= R53*R54*EXP(R66+R62+R67)

The first two terms are the baseline price and the stochastic adjustment factor, respectively. The remaining three terms R66, R62, and R67, are the jump, principal factor, and specific factor contributions, which must be inverse transformed according to equation (2). Because the inverse transformation produces the ratio of the new value to today's value or, in the case of strategic uncertainty, the value of the benchmark, the worksheet must multiply it the benchmark price (modified by any stochastic adjustment) to obtain the new price.

This concludes the discussion of the regional model's representation of stochastic processes. The appendix now turns to how the model applies these principles to the specific sources of uncertainty that are of interest.

# Load

Electricity requirement, or load, in the regional model has characteristics that depend on the timescale. On an hourly basis, loads have distinct on- and off-peak variation. Hourly electricity prices typically move with this load. However, the period duration in the regional model is three months. When we consider load requirements averaged over three months there are

- strong chronological correlation,
- seasonal shapes,
- excursions due to changing economic circumstances, and
- long-term elasticity to electricity prices.

The long-term correlation with electricity prices differs in magnitude and direction from the short-term correlation. That is, loads generally correlate positively to electricity prices in the short term but negatively in the long-term.

This appendix has described the techniques the regional model uses for capturing this broad spectrum of behaviors. This section details the specific formulas and data that implement those techniques.

Electric load serves a number of purposes in the regional model. Its main role is its contribution to energy balance and costs in the regional model. Two other roles that it serves, however, are as a term in the reserve margin calculation and as an influence on medium-term electricity prices.

Appendix L describes how the regional model uses energy requirements to determine energy balance, costs, and reserve margin. This Appendix P will trace back the logic and data from the point where Appendix L begins the discussion. This will be a "bottoms-up" description. The description proceeds from the final values used in Appendix L to the constituent components from which they are constructed. Because the influence of load on medium-term electricity prices is an issue of modeling uncertainty, either that of load or of electricity price, that entire discussion appears in this appendix, in the section "Electricity Price."

## Energy Balance and Cost

The discussion of energy load in Appendix L begins with the average megawatts for the period, on peak and off-peak. The specific worksheet cells in the sample worksheet that provide on peak and off-peak load in column {AQ} are {AQ 183} and {AQ 236}, respectively. The formulas in these two cells are similar. The on peak calculation in {AQ 183} is

=AQ$125*AQ$133

Tracing back from these cells, the reader will find that AQ$125 is the period estimate for the flat load in that period. (By flat load, we mean the average load across all -- on peak and off-peak -- hours.) The value in cell {AQ 133} is a constant factor for converting monthly flat average megawatts to average megawatts over the on peak hours.

The source of these conversion constants is reference [**2**]. The process used to arrive at them is as follows

1. From Northwest Power Pool energy and peak loads for 2000 through 2002, calculate a monthly load factor,
2. Estimate the on peak and off-peak energy using the number of corresponding hours in each month and the simple load duration curve model illustrated in Figure P-24,
3. Estimate the monthly and quarterly multiplication factors, and
4. Recognize that the quarterly factors, illustrated in Figure P-25, change little and are effectively constants.

The preceding section, Stochastic Process Theory, describes how the model represents uncertainties with principal factors, jumps, and specific factors. As shown in Figure P-26, the period estimate for flat load that appears in cell AQ 125 is the product of the benchmark level load requirement {AQ$113} times the inverse transformation (equation 2) for specific variance {AQ$124}, jump {AQ$123}, and combined factor terms {AQ$120}:

=AQ$113*EXP(AQ$123+AQ$120+AQ$124) (12)

The specific factor contribution ({AQ124}) is nonzero, roughly five percent, only for winter and summer seasons. Council staff [3] concluded that this was an appropriate amount of seasonal variation of loads due to weather uncertainty.

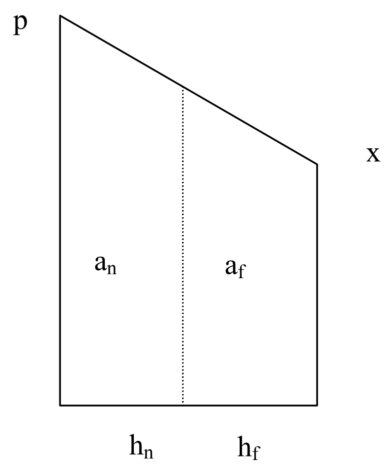


**Figure P-24: Load Duration Curve to Estimate On- and Off-Peak Energies**

$$\text{area or energy } a = a_n + a_f$$
$$\text{hours } h = h_n + h_f$$
$$\text{min load } x = 2(a/h) - p$$
$$\text{average on-peak energy } a_n/h_n = p + (h_n/h)*(x-p)/2$$
$$\text{average off-peak energy } a_f/h_f = (a-a_n)/h_f$$

The jump contribution in cell {AQ 123} represents longer-term excursions in load requirements due to a host of influences, including general economic activity. Because business cycles tend to last several years, the regional model uses only a single jump. The logic for the jump is a variation of the example that the previous section illustrated. In particular, the duration of the jump is specified rather than being a function of the size of the jump, and the recovery is specialized.

| | | | |
|---|---|---|---|
| Spring | | 1.14 | 0.82 |
| Summer | | 1.10 | 0.87 |
| Fall | | 1.14 | 0.82 |
| Winter | | 1.18 | 0.78 |
| | **average** | 1.14 | 0.82 |

**Figure P-25: Quarterly Multiplication Factors (Unitless)**

The wait, size, and duration for jumps are all random variables. The specification for the wait, size, and duration appear in Figure P-27.

AQ125 = =AQ$113*EXP(AQ$123+AQ$120+AQ$124)

| | Q | AQ | AR |
|---|---|---|---|
| 112 | | | |
| 113 | Expected_Value_Set: Non-DSI Load Flat 4x2 | 23768 | 20287 |
| 114 | Principal_Factor_Set: Non-DSI Flat Loads PF | | |
| 115 | Data_Series: NDSI Const Factor | 0.01 | |
| 116 | | | |
| 117 | Data_Series: NDSI Linear Factor | 0.07 | |
| 118 | | | |
| 119 | Data_Series: NDSI Quadratic Factor | 0.01 | |
| 120 | Combined factors | 0.018634537 | 0.018634537 |
| 121 | Jump_Set: Non-DSI Flat Loads JS_002 | | |
| 122 | Combined Jumps | | |
| 123 | | 0 | 0 |
| 124 | Specific Variance | 0.005084832 | 0 |
| 125 | Standard Loads Flat 4x2_001, Subperiod: (all) | 24092 | 20669 |
| 126 | Weather corrected | 24215 | 20669 |

**Figure P-26: Average Megawatt Requirements Calculation**

The jump recovery is such that, after transformation, the jump area equals the recovery area. The size of the jump before transformation equals the size of the recovery before transformation. This is an arbitrary choice, to make the calculation simple. To make of the areas after transformation the same, the duration of the recovery is a function of the jump duration and size. To make the areas the areas the same, we have D_1(exp(J)-1)=D_2(1-exp(-J)), where D_1 is the duration of the original jump and D_2 is the duration of the "recovery" jump. This gives us D_2=D_1*exp(J). Having equal areas means the load excursions average out over a sufficiently long (D_1+D_2) period.

**Random Variables**

| | Type | Cell | Distribution | Parameters | |
|---|---|---|---|---|---|
| Jump 1 | wait | {{R121}} | **uniform** | min 0 | max 85 |
| | size | {{S121}} | **uniform** | min -0.10 | max 0.80 |
| | duration | {{T121}} | **uniform** | min 8 | max 20 |
| Principal Factors | offset | {{R114}} | **normal** | mean 0 | stdev 1 |
| | linear | {{R116}} | **normal** | mean 0 | stdev 1 |
| | quadratic | {{R118}} | **normal** | mean 0 | stdev 1 |
| Specific Variance | | {{row 124}} | **normal** | mean 0 | stdev 0.05 |

**Figure P-27: Assumption Cell Values for Load**

The combined principal factors have the weightings, distributions, and eigenvalues illustrated in Figure P-29. The Council selected these to provide realistic behavior [**3**]. The validation for this behavior is the topic of this section's "Comparison with the Council's Load Forecast", below.

Finally, the baseline load forecast {row 113} corresponds to the Council's weather-adjusted, non-DSI load forecast [**4**] and reflects the following assumptions.

- Nine percent losses for distribution and transmission
- Existing conservation through hydro-year 2003

| | R | S | T |
|---|---|---|---|
| 121 | 48.54747 | -0.03909 | 16.17535 |

| | | | interpretation |
|---|---|---|---|
| **R122** | =$R$121 | wait_1 | start time of jump 1 |
| **S122** | =R122+ $T$121 | wait_1+ duration_1 | end time of jump 1 |
| **T122** | =$S$121 | size_1 | size_log xfr jump 1 |
| **U122** | =S122 | end time of jump 1 | start time of recovery 1 |
| **V122** | =U122+ S122*EXP(T122) | end time of jump 1 + duration recovery 1 | end time of recovery 1 |
| **W122** | =-T122 | -size_1 | size_log xfr recovery 1 |

**R123** = IF(AND(R$46>$R122,R$46<=$S122),$T122,0)+   jump_1
IF(AND(R$46>$U122,R$46<=$V122),$W122,0)   recovery_1

**S123** identical, except S$46 instead of R$46
**T123** identical, except T$46 instead of R$46

**Figure P-28: Jump Data and Formulas for Load**

- Frozen efficiency for hydro year 2004 and beyond [17]
- Monthly distribution of annual energies, and the aggregation of those monthly energies into quarterly energies.

This baseline forecast serves as the median of the distribution of energy requirements. The model has all future conservation in the conservation supply curves described in Appendix L. The only exceptions are conservation implemented before 2003 and conservation due to building codes and appliance standards implemented before 2003.

**Pricipal Factors**

| Dec of Cal Year | offset | linear | quadratic |
|---|---|---|---|
| Weight | | | |
| | 0.000 | 0.300 | 0.051 |
| Value | | | |
| 2003 | 0.01 | 0.01 | 0.00 |
| 2004 | 0.01 | 0.02 | 0.00 |
| 2005 | 0.01 | 0.03 | 0.00 |
| 2006 | 0.01 | 0.04 | 0.00 |
| 2007 | 0.01 | 0.05 | 0.01 |
| 2008 | 0.01 | 0.06 | 0.01 |
| 2009 | 0.01 | 0.07 | 0.01 |
| 2010 | 0.01 | 0.08 | 0.02 |
| 2011 | 0.01 | 0.09 | 0.02 |
| 2012 | 0.01 | 0.10 | 0.03 |
| 2013 | 0.01 | 0.11 | 0.04 |
| 2014 | 0.01 | 0.12 | 0.04 |
| 2015 | 0.01 | 0.13 | 0.05 |
| 2016 | 0.01 | 0.14 | 0.06 |
| 2017 | 0.01 | 0.15 | 0.07 |
| 2018 | 0.01 | 0.16 | 0.08 |
| 2019 | 0.01 | 0.17 | 0.09 |
| 2020 | 0.01 | 0.18 | 0.10 |
| 2021 | 0.01 | 0.19 | 0.11 |

**Figure P-29: Principal Factors for Load**

## Energy Reserve Margin

Appendix L describes how the model uses weather-adjusted energy load requirement in each period to determine the energy reserve margin. The energy reserve margin plays a prominent role in the decision criterion to proceed with construction of new power plants.

The load estimate in cell {AP289} is the hydro year's average, weather-corrected non-DSI load (the range {AL126: AO126}), plus the DSI load in the final period.

=-AVERAGE(AL126:AO126)-AO327

The model's weather corrected load is simply the load, less the stochastic part that

[17] The frozen efficiency load forecasts assume no new conservation of any kind, although it does incorporate any *prior* conservation and the effect of *existing* codes and standards on future requirements. Instead, conservation supply curves represent future conservation measures and new codes and standards.

represents weather variation in the winter and summer. Specifically, if the user examines cell {AO 126}, the last cell in the average computed in the previous equation, they will find formula

=AO$113*EXP(AO$123+AO$120)

This of course matches to equation (12), less the term that corresponds to specific variance for weather.

## Hourly Behavior

The regional model captures hourly price and requirements information through descriptive statistics. In particular, the transformed hourly variation in load given by equation (3) and its correlation with hourly electricity price determine revenues to meet load. Appendix L describes the calculation in its discussion of Single-Period load behavior. The intra-period hourly load variation is 25 percent, as specified in cell {R 185}. The hourly correlation with other variables appears in this section's, "Hourly Correlation" discussion, below.

## Comparison with the Council's Load Forecast

Statute requires that the Council's Northwest Regional Conservation and Electric Power Plan have a 20-year forecast of electricity demand.[18] This forecast of electricity demand serves as the basis for other, alternative forecasts that are necessary for specific purposes, such as a source of input data for the Aurora™ model. The alternative forecasts use assumptions that differ from those for the primary forecast. For example, an alternative forecast may use different assumptions about energy losses or about the representation of conservation. To compare the regional model's load forecast to the primary forecast, this section determines what adjustments to the primary forecast would make the two forecasts comparable. The section then compares the modified primary forecast and the loads from regional model futures.

The regional model uses a non-DSI forecast. The model simulates the behavior of DSI load separately, using electricity and aluminum prices in the model. (See Appendix L for a description of DSI modeling in that appendix's "Multiple Period" section of Principles.) The non-DSI load forecast appearing in the Plan (Appendix A) is of sales (MWa) by calendar year, including conservation expected to arise from a forecast of retail electricity rates but excluding conservation due to codes and standards implemented since the Council's 4$^{th}$ Plan. The basis of electricity rate forecast is an earlier calculation of long-term equilibrium wholesale prices. The annual loads appear in Table P-1, which details the values in Appendix A, Table A-2.

[18] Public Law 96-501, Sec. 4(e)(3)(D)

| | Non-DSI Sales (Price Effects) | | | | |
|---|---|---|---|---|---|
| YEAR | Low | Medlo | Medium | Medhi | High |
| 2004 | | | 18072 | | |
| 2005 | 17191 | 17824 | 18433 | 19020 | 20221 |
| 2006 | 17200 | 17955 | 18663 | 19360 | 20727 |
| 2007 | 17214 | 18098 | 18906 | 19721 | 21257 |
| 2008 | 17228 | 18239 | 19145 | 20093 | 21814 |
| 2009 | 17257 | 18398 | 19405 | 20479 | 22397 |
| 2010 | 17297 | 18570 | 19688 | 20879 | 23007 |
| 2011 | 17320 | 18729 | 19959 | 21275 | 23598 |
| 2012 | 17353 | 18906 | 20251 | 21696 | 24214 |
| 2013 | 17366 | 19067 | 20521 | 22106 | 24843 |
| 2014 | 17430 | 19274 | 20830 | 22547 | 25501 |
| 2015 | 17489 | 19482 | 21147 | 23000 | 26187 |
| 2016 | 17522 | 19672 | 21456 | 23449 | 26906 |
| 2017 | 17554 | 19864 | 21770 | 23907 | 27645 |
| 2018 | 17586 | 20058 | 22089 | 24375 | 28407 |
| 2019 | 17619 | 20254 | 22413 | 24853 | 29190 |
| 2020 | 17652 | 20453 | 22742 | 25341 | 29997 |
| 2021 | 17686 | 20653 | 23076 | 25839 | 30827 |
| 2022 | 17719 | 20855 | 23415 | 26347 | 31681 |
| 2023 | 17753 | 21059 | 23760 | 26866 | 32560 |
| 2024 | 17787 | 21265 | 24109 | 27396 | 33466 |
| 2025 | 17822 | 21474 | 24464 | 27937 | 34397 |

**Table P-1: Council's Non-DSI Calendar-Year Sales Forecast**

Some background about the Council's load-forecasting methods will be helpful to following the development of forecast adjustments. Electricity prices, building codes, and appliance standards determine the level of pursuit of conservation and consequently, energy requirements. Because Council policy can affect codes and standards directly and electricity prices indirectly, it is useful to separate these influences.

One way approach this decomposition is to start with a "frozen efficiency" load forecast. The frozen efficiency load forecast reflects the amount of energy requirement that would arise only from current appliance standards and codes. Next, one would attempt to estimate how much conservation would arise in the future from the price effect of retail electricity rates. That is, ratepayers should pursue some conservation because it costs less than the electricity it displaces. The Council refers to load forecast net of this reduction as the "price-effects" forecast.

The Council has demonstrated, however, that additional benefit accrues to ratepayers from conservation beyond that which ratepayers would pursue to offset anticipated electricity purchases. Specifically, additional conservation can reduce fuel cost and defer the utility's capacity expansion. Electric power rates may go up or down because of this conservation, but this additional conservation would minimize ratepayers' total power costs. To induce this additional conservation, however, the region typically must pursue additional codes and standards or other conservation measures. The Council refers to the forecast that arises by virtue of this additional conservation as a "sales" forecast, that is, the actual sale of electricity to consumers after the effects of codes and standards, energy conservation, utility program savings, and consumers' own response to prices.

The regional model, on the other hand, represents conservation using supply curves, which include new utility programs, appliance codes and standards, and price effects. Consequently, the regional model needs the frozen efficiency load forecast. If price effects or program saving were subtracted from the load, the model would be double counting their effect.

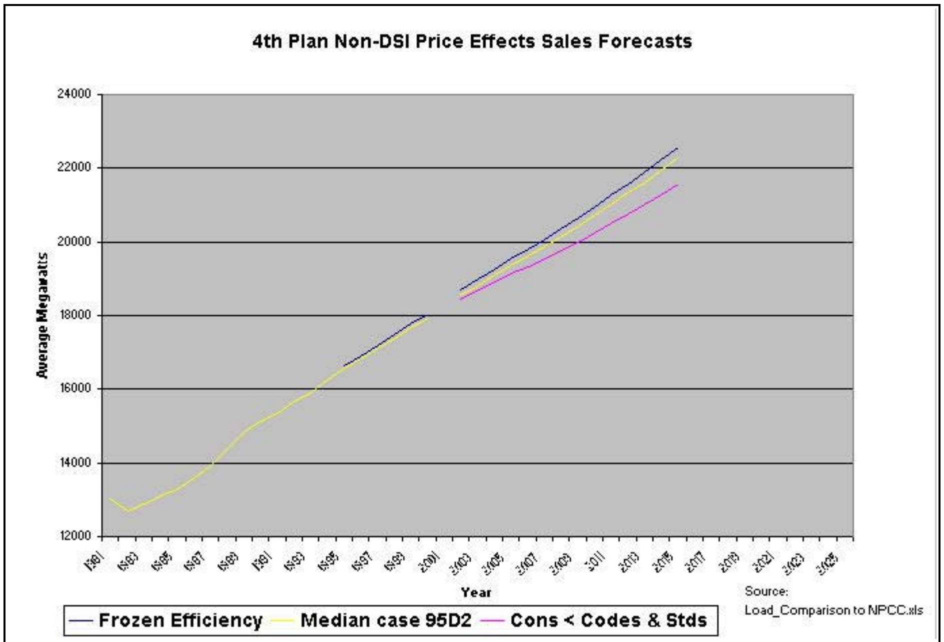


**Figure P-30: Comparison of 4th Plan Load Forecasts**

As mentioned in Appendix A, the load forecast of the Fifth Plan builds directly on work of the Fourth Plan. Figure P-30 illustrates the relationship in the Fourth Plan between the

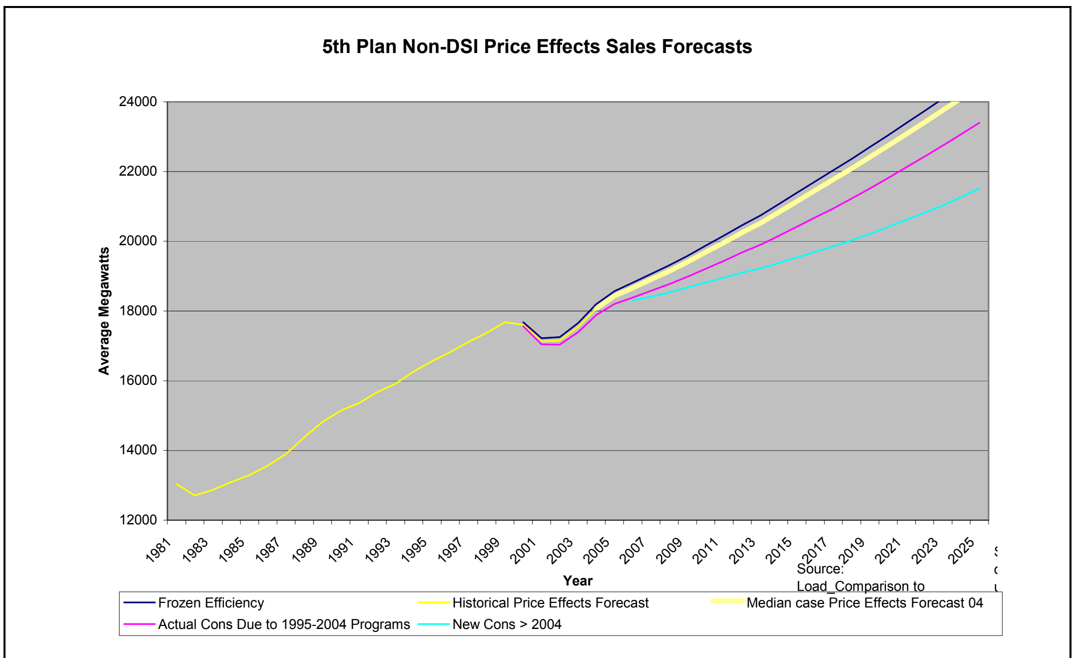


**Figure P-31: Comparison of 5th Plan Load Forecasts**

frozen-efficiency, price-effects, and sales load forecasts. To prepare the load forecast for the Fifth Power Plan, the Council uses a revised price-effects forecast (Table A-2). The revised price-effects forecast builds on the price-effects forecast in the Fourth Plan, incorporating history over the last five years. In particular, the revised price-effects forecast does not reflect the conservation arising from codes and standards enacted since the Fourth Plan. Figure P-31, which has five loads, illustrates the resulting situation. Before 2004, it shows an estimate of the price-effects forecast due to actual history. This price-effects forecast is continued after 2004 as the "median case price-effects forecast 04". We know, however, that codes and standards since 1995 have in fact reduced loads, and ***this reduced forecast is our best estimate of where a price-effects forecast might wind up if the Council had updated the analysis for the fifth Plan***. (The effect on loads of any new conservation, subsequent to the ***fifth*** plan is captured by the line "new conservation > 2004.") Similarly, our best estimate of where the "frozen efficiency" load forecast would lie relative to the price-effects forecast comes from using the increment between the “price-effects” forecast and the "frozen efficiency" forecast in the last plan. In summary, therefore, the "frozen efficiency" load forecast used in the regional model starts with a revised price-effects forecast anchored in 1995 but reflecting economic history since then, reduces this forecast by the effect of conservation due to codes and standards implemented since the fourth plan, and adds the increment for frozen efficiency increment developed the fourth plan. The frozen efficiency adders appear in Table P-2, and the estimated Code and Standards Savings since the Fourth Plan are in Table P-3.

| | Frozen Efficiency Adders (From 95D4) | | | | |
|---|---|---|---|---|---|
| YEAR | Low | Medlo | Medium | Medhi | High |
| 2004 | 66 | 70 | 78 | 87 | 105 |
| 2005 | 60 | 64 | 74 | 86 | 109 |
| 2006 | 53 | 57 | 68 | 83 | 111 |
| 2007 | 48 | 53 | 66 | 83 | 116 |
| 2008 | 46 | 51 | 67 | 86 | 125 |
| 2009 | 46 | 51 | 69 | 91 | 137 |
| 2010 | 45 | 51 | 71 | 97 | 149 |
| 2011 | 46 | 52 | 74 | 103 | 163 |
| 2012 | 49 | 56 | 80 | 114 | 184 |
| 2013 | 57 | 67 | 92 | 131 | 210 |
| 2014 | 65 | 76 | 105 | 151 | 238 |
| 2015 | 72 | 85 | 116 | 167 | 265 |
| 2016 | 72 | 85 | 116 | 167 | 265 |
| 2017 | 72 | 85 | 116 | 167 | 265 |
| 2018 | 72 | 85 | 116 | 167 | 265 |
| 2019 | 72 | 85 | 116 | 167 | 265 |
| 2020 | 72 | 85 | 116 | 167 | 265 |
| 2021 | 72 | 85 | 116 | 167 | 265 |
| 2022 | 72 | 85 | 116 | 167 | 265 |
| 2023 | 72 | 85 | 116 | 167 | 265 |
| 2024 | 72 | 85 | 116 | 167 | 265 |
| 2025 | 72 | 85 | 116 | 167 | 265 |

**Table P-2: Frozen Efficiency Adders**

| | Conservation Captured Since the 4th Plan | | |
|---|---|---|---|
| YEAR | Residential | Commercial | Total |
| 2004 | 174 | 14 | 187 |
| 2005 | 212 | 18 | 231 |
| 2006 | 254 | 23 | 276 |
| 2007 | 298 | 27 | 325 |
| 2008 | 343 | 31 | 373 |
| 2009 | 387 | 35 | 422 |
| 2010 | 433 | 39 | 472 |
| 2011 | 478 | 43 | 521 |
| 2012 | 524 | 47 | 571 |
| 2013 | 571 | 50 | 621 |
| 2014 | 618 | 54 | 672 |
| 2015 | 664 | 58 | 722 |
| 2016 | 711 | 62 | 773 |
| 2017 | 758 | 66 | 824 |
| 2018 | 794 | 70 | 863 |
| 2019 | 830 | 74 | 903 |
| 2020 | 852 | 78 | 929 |
| 2021 | 875 | 82 | 956 |
| 2022 | 898 | 86 | 984 |
| 2023 | 922 | 90 | 1012 |
| 2024 | 946 | 94 | 1040 |
| 2025 | 966 | 98 | 1064 |

Source: Load_Comparison to NPCC.xls

**Table P-3: Conservation Since the 4th Plan**

Finally, the revised forecast must capture losses due to distribution and transmission. An energy loss, which amounts to nine percent, will increase the end use forecast measured at the customers’ electric power meters. The power plants in the regional model, of course, must meet both end use and losses of energy.

The data presented in tables and graphs to this point reflect calendar year averages. Because the regional model uses hydro quarters, we must make the conversion to hydro year averages. The final formula for combining these effects is in Figure P-32. The table of the resulting values, by hydro year, appears in Table P-4.[19] The load forecast in this table serves as the basis for comparison between the Council's primary forecast and the regional model loads.

One subtlety of the formula in Figure P-32 is that we have implicitly assumed transmission and distribution losses are included in the frozen efficiency adders and the codes and standards savings. In any case, the adjustment for losses due to these effects is very small.

$$L_{HY,T} = \frac{8}{12}\left\{(1+\lambda)\cdot L_{CY,T} + PE_{CY,T} - C_{CY,T}\right\} + \frac{4}{12}\left\{(1+\lambda)\cdot L_{CY,T-1} + PE_{CY,T-1} - C_{CY,T-1}\right\}$$

where

$L_{HY,T}$ is load (MWa) for hydro year T

$\lambda$ is loss factor (0.09)

$L_{CY,T}$ is load (MWa) for calendar year T

$PE_{CY,T}$ is price effect for calendar year T

$C_{CY,T}$ is conservation in calendar year T arising from programs implemented since the 4th Plan

**Figure P-32: Calculation of Adjusted Primary Forecast**

The regional model uses futures containing chronological loads that can vary quite dramatically. Jumps and excursions due to business cycles and weather are evident in

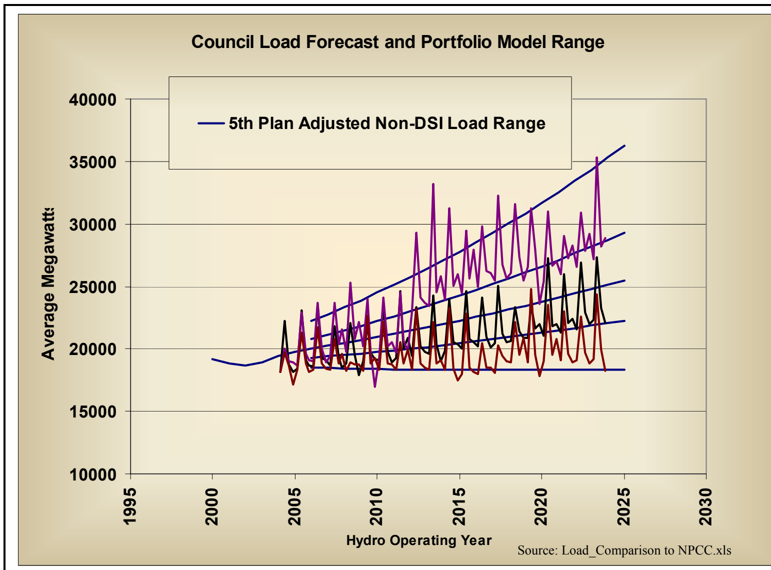


**Figure P-33: Regional Model Loads from Futures**

[19] The hydro year September 2006 through August 2007 is defined to be hydro year 2007.

individual futures, as illustrated in Figure P-33. This figure compares three randomly chosen futures from the 750 futures to the five load forecasts presented in Table P-4. Figure P-33 also has the disadvantage of comparing quarterly energy load values against annual averages. Even with only three futures, the figure is rather difficult to sort out. Two refinements to this graph that help make the data from the regional model more accessible are the presentation of the load data across all futures statistically and the averaging the quarterly data into annual values.

| HYDRO | Olivia Input Loads | | | | |
|---|---|---|---|---|---|
| YEAR | Low | Medlo | Medium | Medhi | High |
| 2004 | | | 19398 | | |
| 2005 | | | 19800 | | |
| 2006 | 18516 | 19298 | 20045 | 20778 | 22234 |
| 2007 | 18472 | 19393 | 20249 | 21112 | 22755 |
| 2008 | 18431 | 19492 | 20458 | 21462 | 23308 |
| 2009 | 18403 | 19604 | 20682 | 21828 | 23892 |
| 2010 | 18388 | 19733 | 20931 | 22211 | 24505 |
| 2011 | 18366 | 19858 | 21179 | 22597 | 25116 |
| 2012 | 18346 | 19994 | 21441 | 23002 | 25742 |
| 2013 | 18320 | 20129 | 21699 | 23414 | 26393 |
| 2014 | 18324 | 20293 | 21980 | 23847 | 27072 |
| 2015 | 18343 | 20473 | 22279 | 24298 | 27782 |
| 2016 | 18335 | 20634 | 22567 | 24739 | 28507 |
| 2017 | 18314 | 20787 | 22852 | 25180 | 29250 |
| 2018 | 18302 | 20951 | 23151 | 25639 | 30025 |
| 2019 | 18295 | 21121 | 23459 | 26113 | 30828 |
| 2020 | 18297 | 21303 | 23782 | 26608 | 31665 |
| 2021 | 18304 | 21491 | 24115 | 27118 | 32532 |
| 2022 | 18311 | 21681 | 24453 | 27638 | 33425 |
| 2023 | 18318 | 21872 | 24796 | 28170 | 34344 |
| 2024 | 18324 | 22065 | 25144 | 28713 | 35290 |
| 2025 | 18334 | 22264 | 25502 | 29271 | 36269 |

Source: Load_Comparison to NPCC.xls

**Table P-4: Hydro-Year Forecast for Regional Model**

Figure P-35 compares the 0, $10^{th}$, $50^{th}$, $90^{th}$, and $100^{th}$ percentiles against the forecast from Table P-4. The data falls somewhat outside of the jaws of the revised, primary forecast, as we would expect. The quarterly values have greater variation largely due to seasonal variation, and the Council believes there is some very small probability that annual average load will fall outside of the jaws.

Figure P-34 addresses the second problem, replacing quarterly values with annual averages. Now it is evident, for example, that the median forecast ($50^{th}$ percentile) lies directly on top of the adjusted Council "Medium" forecast.

In Figure P-34, there appears to be greater uncertainty associated with the futures in the early part of the study than near the end of the study. Indeed, if these forecasts are truly comparable we would expect the 0 percent and $100^{th}$ percentiles to lie outside of the jaws.

One of the things going on here is the difference in assumption about electricity prices between the Council's primary forecast and the regional model. The Council's primary forecast, again, stems from a 1995 load forecast, which assumes much smaller variation in electricity price. The regional model sees electricity prices that are orders of magnitude larger, in particular. The regional portfolio model incorporates electricity price elasticity of loads. This elasticity will cause the variation in load excursions to diminish on average, especially in outlying years where greater electricity price variation occurs.

Another influence is the limited samples of futures. The regional model data presented in Figure P-34 are directly from the model's Monte Carlo simulations. As the sample size increases beyond the 750 samples reflected here, the zero percent and 100 percent deciles

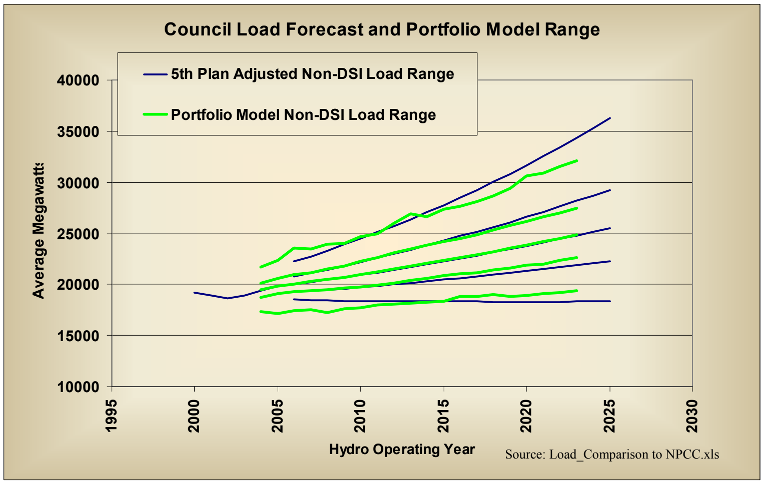


**Figure P-34: Annual Averages of Deciles for Regional Model Loads**

would grow apart. The maximum range of excursion in the Monte Carlo simulation is sensitive to the number of samples in the simulation.

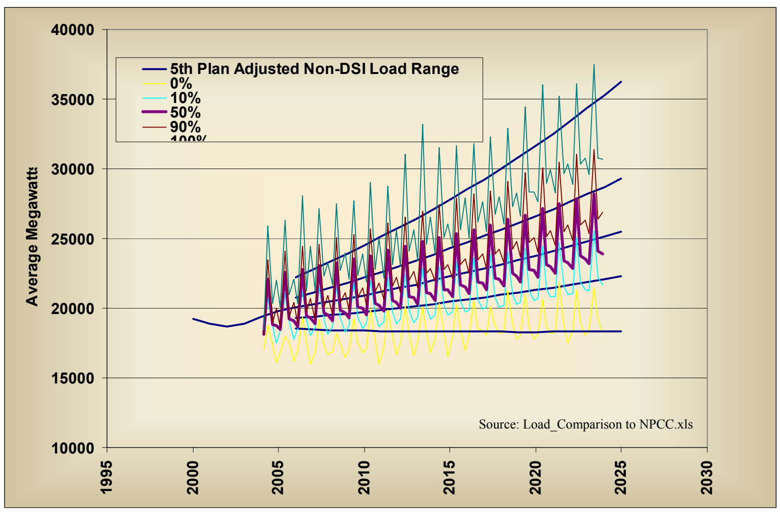


**Figure P-35: Deciles for Quarterly Load**

Because the regional model simulates hydro quarters, conversion of energy to that period is necessary. The basis of conversion (Ref [**5**]) is averages of monthly load allocation factors from Ref [**6**], which is integral to the study for the Council's primary load forecast.

## Gas Price

Like electricity requirement load, natural gas price has characteristics that to depend on the time scale. Although natural gas price does not vary a great deal across the day, there can be substantial variation within the month. The kinds of behavior that natural gas price demonstrates include:

- Chronological correlation, stronger than that for electricity prices perhaps due to the storage capability of natural gas,
- Seasonal shapes,
- Excursions due to disequilibrium of long-term supply and demand,
- Daily variation within the month and hydro quarter,
- Basis differential, in particular between regions separated by the Cascade mountain range, and
- Relatively small hourly price variation, because of storage capability within natural gas transmission lines. This eliminates the requirement for modeling on- and off-peak price differences.

Natural gas prices also exhibit correlation with other variables. Natural gas prices correlate with loads and with electricity prices because weather affects all of these. Moreover, natural gas-fired generation is a marginal resource for power generation and consequently affects electricity price. Finally, higher electricity load generally places higher demand on natural gas markets. The model must capture both the long-term and short-term correlation among these variables.

Natural gas prices serve several functions or roles within the regional model. Short-term prices determine economic dispatch of gas-fired thermal generation. Forward gas prices feed decision criteria for the construction of new capacity. This section discusses the simulation of each of these uses.

As noted above, gas prices also influences longer-term electricity price. This influence of natural gas price on electricity prices appears in the discussion of electricity price uncertainty (See the section "Electricity Price," below). Short-term correlation is outlined at the end of this chapter.

## Worksheet Function and Formulas

Appendix L identifies how the regional model uses natural gas prices for the dispatch of gas-fired thermal generation and for the decision criteria for construction of new power plants. Appendix L traces natural gas price back to specific workbook cells. The description of natural gas prices in this Appendix P begins with those cells and continues the description back to the “building blocks” of these prices.

East of Cascade's gas prices {AQ180} are derived from those for west of Cascade's {AQ 68}. The worksheet range {A176: U176} provides the seasonal basis differential. The source of these basis differential values is [**7**]. The formulas in {Row 178} limit the lowest price in the East to $.20 per million BTU. This constraint assures Eastside prices remain positive irrespective of what Westside prices may do.

The formulas in {Row 180} add the values in {Row 179} to those in {Row 178}, but the values in {Row 179} are zero. This is a vestige of earlier logic, which attempted to add a contribution for fixed costs differentially to the Eastern natural gas prices. Council staff later decided that a fixed-cost adder would be inappropriate.

A lognormal process creates West of Cascade's natural gas prices, using combined factors, specific variation, and two jumps. Figure P-36 identifies the random variables for the natural gas price representation. The character of the jumps differs from that for the load's representation. The Council deemed the original size and duration of the jumps too large to be realistic. The Council substituted the representation in Figure P-37.

| | R | S |
|---|---|---|
| 63 | 14.7678 | 0.0886 |
| 64 | 12.1453 | 0.1863 |

| Cell | Formula | | interpretation |
|---|---|---|---|
| R65 | =$R$63 | wait_1 | start time of jump 1 |
| S65 | =R65+ IF($S$63= 0,0,3/$S$63) | wait_1+ 3/size_1 | end time of jump 1 |
| T65 | =$S$63 | size_1 | size_log xfr jump 1 |
| U65 | =S65 | end time of jump 1 | start time of recovery 1 |
| V65 | =U65+ S65*EXP(T65) | end time of jump 1 + duration recovery 1 | end time of recovery 1 |
| W65 | =-T65/10 | -size_1/10 | size_log xfr recovery 1 |
| X65 | =V65+ $R$64 | end time of recovery 1+ wait_2 | start time of jump 2 |
| Y65 | =X65+ IF($S$64= 0,0,3/$S$64) | wait_2 + 3/size_2 | end time of jump 2 |
| Z65 | =$S$64 | size_2 | size_log xfr jump 2 |
| AA65 | =Y65 | end time of jump 2 | start time of recovery 2 |
| AB65 | =AA65+ Y65*EXP(Z65) | end time of jump 2 + duration recovery 2 | end time of recovery 2 |
| AC65 | =-Z65/10 | -size_2/10 | size_log xfr recovery 2 |

| | | | |
|---|---|---|---|
| R66 | = IF(AND(R$46>$R65,R$46<=$S65),$T65,0)+ | jump_1 | source: L28_P.xls |
| | IF(AND(R$46>$U65,R$46<=$V65),$W65,0)+ | recovery_1 | |
| | IF(AND(R$46>$X65,R$46<=$Y65),$Z65,0)+ | jump_2 | |
| | IF(AND(R$46>$AA65,R$46<=$AB65),$AC65,0) | recovery_2 | |

**Figure P-36: Jump Data and Formulas for Natural Gas Price**

The specific variance contributes to shoulder months, the spring in the fall. In contrast with several other stochastic variables, there seems to be much greater uncertainty in the price of natural gas during these off-peak seasons (see Reference [**8**]). This is perhaps due, in part, to the storage capability for natural gas and the buying that takes place in anticipation of the heating season and occasional surpluses resulting from warm winters. The values for the specific variances appear in Figure P-37.

**Random Variables**

| | Type | Cell | Distribution | Parameters | | |
|---|---|---|---|---|---|---|
| Jump 1 | wait | {{R63}} | **uniform** | min 0 | max 30 | |
| | size | {{S63}} | **uniform** | min 0 | max 0.70 | |
| Jump 2 | wait | {{R64}} | **uniform** | min 4 | max 20 | |
| | size | {{S64}} | **uniform** | min 0 | max 0.70 | |
| Principal Factors | offset | {{R56}} | **triangle** | min -1 | mode 0 | max 1 |
| | linear | {{R58}} | **triangle** | min -1 | mode 0.1 | max 1 |
| | quadratic | {{R60}} | **triangle** | min -1 | mode 0 | max 1 |
| Specific Variance | | {{row 67}} | **normal** | mean 0 | stdev 0.30 | |

source: L28_P.xls

**Figure P-37: Assumption Cells for Natural Gas Price**

The principal factors appear Figure P-38. These were chosen largely to create realistic behavior. Some comparative statistics appear in the section "Comparison with the Council's Gas Price Forecast," below.

**Pricipal Factors**

| Dec of Cal Year | offset | linear | quadratic |
|---|---|---|---|
| | Weight | | |
| | 0.350 | 0.700 | 1.000 |
| | Value | | |
| 2003 | 0.50 | 0.07 | 0.00 |
| 2004 | 0.50 | 0.14 | 0.01 |
| 2005 | 0.50 | 0.21 | 0.02 |
| 2006 | 0.50 | 0.28 | 0.03 |
| 2007 | 0.50 | 0.35 | 0.05 |
| 2008 | 0.50 | 0.42 | 0.07 |
| 2009 | 0.50 | 0.49 | 0.10 |
| 2010 | 0.50 | 0.56 | 0.13 |
| 2011 | 0.50 | 0.63 | 0.16 |
| 2012 | 0.50 | 0.70 | 0.20 |
| 2013 | 0.50 | 0.77 | 0.24 |
| 2014 | 0.50 | 0.84 | 0.29 |
| 2015 | 0.50 | 0.91 | 0.34 |
| 2016 | 0.50 | 0.98 | 0.39 |
| 2017 | 0.50 | 1.05 | 0.45 |
| 2018 | 0.50 | 1.12 | 0.51 |
| 2019 | 0.50 | 1.19 | 0.58 |
| 2020 | 0.50 | 1.26 | 0.65 |
| 2021 | 0.50 | 1.33 | 0.72 |

source: L28_P.xls

**Figure P-38: Principal Factors for Natural Gas Prices**

The influence of principal factors, specific variance, and jumps combine just as they did for the construction of load futures. The cell {AQ68} contains the formula that combines these:

= AQ53*AQ54*EXP(AQ66+AQ62+AQ67)

where {AQ53} contains the benchmark (Council "medium" forecast, Reference [7]) value for natural gas in this period, {AQ54} is a special "stochastic adjustment," {AQ66} contains the sum of the jumps, {AQ62} is the sum of the factors, and {AQ67} is the contribution from the specific variance (seasonal uncertainty). The stochastic adjustments in row {66} are multipliers that would guarantee that the average, rather than the median, of the prices in that period match the benchmark. Early in the Council's studies, the Council identified their "medium" forecast with the average of the futures prices. Subsequently, the Council decided that the Council's medium forecast is a median forecast and the stochastic adjustment became 1.0 (no effect). That is, the Council constructs its forecast so that there is equal likelihood of the long-term equilibrium price being on either side of the forecast.

## Forward Prices for Decision Criteria

Forward prices for natural gas play a key role in decisions about whether to construct new gas-fired power plants. The price of its fuel largely determines the value of the gas-fired power plant, and if future natural gas prices are low, the power plant will have greater value.

Some decision makers believe forward prices for natural gas are the best predictor of future spot price. The relationship between forward prices and current and future spot prices has been the subject of financial research for over 70 years. Arbitrage between forward and *current* spot price is possible for financial instruments and for commodities that can be stored. There is therefore a strict relationship between current spot prices and forward prices for these products. Natural gas, however, can only be stored in significant volumes up to about six months. Beyond that period, arbitrage opportunities are rare or nonexistent. For electricity, of course, the opportunities are even scarcer.

The relationship between forward prices and future spot prices is even weaker. The argument is often that the forward price incorporates all information about future spot price. This ignores, however, the question of whether the forward price in fact does a good job of predicting spot price. A substantial body of research has demonstrated that long-term forward prices are a poor predictor of future spot prices for commodities that cannot be stored.[20] (In this context, "long-term" would be any period significantly longer than that which the commodity is stored.) Moreover, such an assessment ignores the influence of scarcity or abundance on the attitudes of hedgers or speculators, and these can bias the price up or down when there is uncertainty, even when all market participants share the same view of *expected* future spot price.[21]

Even if long-term forward prices are no better than throwing darts for predicting future prices, however, this does not mean that forward prices are irrelevant to the value of a power plant. On the contrary, an appropriate use of forward contracts is for hedging. If decision makers purchase the natural gas forward and sell the output of the power plant forward before proceeding with construction, changes in the values for forward contracts for natural gas and electricity will offset any change in the value of the plant due to fuel and output price variation. This provides a means for managing such risk associated with the "merchant" (un-hedged) portion of the plant. That is, an owner can make the merchant portion as small as desirable by hedging the rest of the plant. For various reasons, this hedging is likely to "lock in" as loss for the owners. However, decision makers view this loss as the cost of reducing risk, much like an insurance premium.

Forward prices continuously change, and this is an important source of uncertainty. One challenge for the portfolio model is to continuously forecast changing forward prices for natural gas and electricity. The question is, what is a reasonable basis for making such a forecast? Experience shows that forward prices tend to track current spot prices. Figure P-39 (Reference [**9**]) illustrates the relationship over time between current spot prices and a contract for delivery of natural gas in July 2003. The same kind of relationship exists for electricity. FERC analysis of electricity prices[22] in fact explicitly supports the position that spot prices move forward prices. (See discussion of the role of electricity spot prices in forecasting electricity forward prices on page P-75.)

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[20] See, for example, Frank K. Reilly, ***Investment Analysis and Portfolio Management***, 2nd ed., The Dryden Press, Chicago 1979. See especially Chapter 24, "Commodity Futures," which discusses research for shell eggs, cattle, and other perishable commodities. For a more recent examination of electricity prices, see Longstaff and Wang, "Electricity Forward Prices: A High-Frequency Empirical Analysis," Anderson Graduate School of Management, UCLA, 2002.

[21] John C. Hull, ***Options, Futures, and Other Derivatives***, 4th ed., Prentice Hall 2000. See section 3.12, "Futures Prices and the Expected Future Spot Price."

[22] U.S. Dept. of Energy, Federal Energy Regulatory Commission, ***Final Report On Price Manipulation In Western Markets, Fact-Finding Investigation Of Potential Manipulation Of Electric And Natural Gas Prices***, Docket No. PA02-2-000, March 2003. PDF version.

This observation led the Council to adopt averages of current spot prices for natural gas over the prior 18 months as a simulated forecast of natural gas forward prices. In the cell {{AQ 249}}, the model averages the prior six periods (18 months) to estimate the

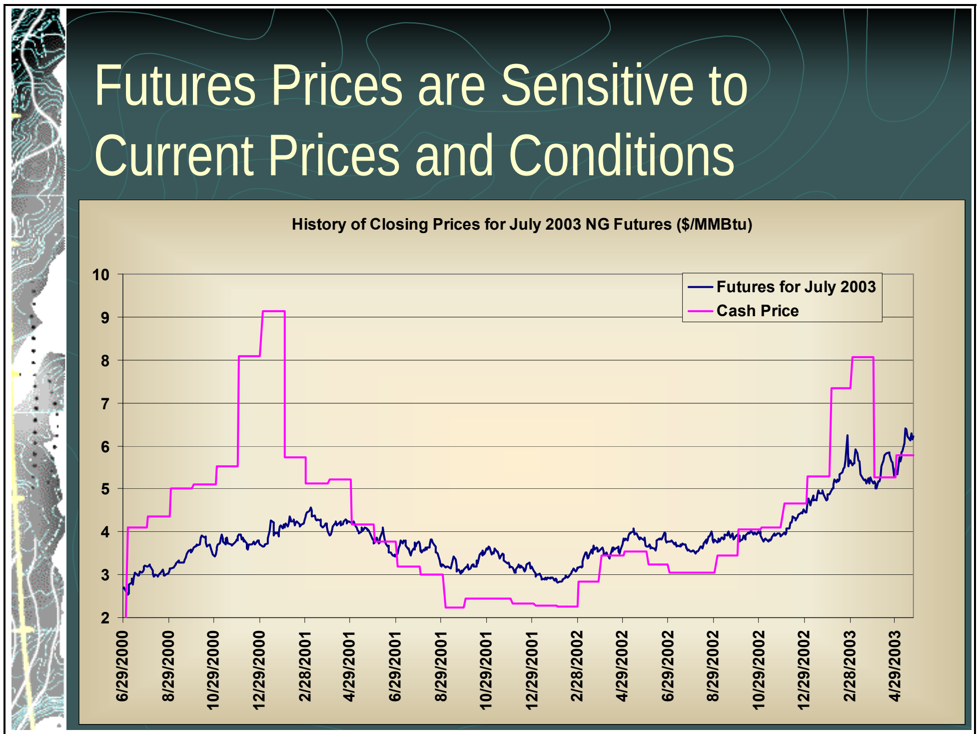



**Figure P-39: Relationship Between Futures and Spot Prices**

corresponding forward priced for the decision criteria.

## Hourly Behavior

Hourly volatility of natural gas prices within the period is taken as 10 percent, as indicated in the cell {{R55}}. Hourly price data for gas is not available to the Council, but casual exchanges with traders suggest this figure is representative. This appendix discusses correlation of natural gas prices to other variables at the end of this chapter.

## Comparison with the Council's Gas Price Forecast

In addition to preparing a long-term load forecast for the Region, the Council prepares and updates long-term natural gas price forecasts. A comparison of the regional model's gas prices to the Council's forecast is more direct than the comparison to loads provided in the previous section.

Figure P-40 illustrates the quarterly natural gas price averages for four randomly chosen futures. Also shown, with the shaded area, is the range (high, median, and low) associated with the Council's natural gas price forecast. The quarterly averages fall well outside the range. In most of the futures, for example, there is at least one quarter when the natural gas price exceeds $10/MMBTU, well above the Council's "high" forecast. Some of the same caveats used in the comparison of the regional portfolio model's futures to the Council's load forecast apply here. The Council's forecast is a long-term equilibrium price forecast and does not capture excursions due to, for example, two- or three-year disruptions in supply and demand balance. Also, the Council's forecast is of annual averages, and quarterly averages will be more volatile.

By looking at statistical averages of the quarterly values for the regional portfolio model's natural gas price futures (Figure P-41), a more representative picture emerges. Quarterly averages for gas price can run from as low as $0.90 per MMBTU (2004 $) to as high as $28.24 per MMBTU, although those extremes are unlikely. The seasonal variation in price is not as extreme as that for load, so calculating annual averages for comparison with the Council's forecast is not essential. By carefully examining the deciles for quarterly gas price averages, it appears (Figure P-42) that there is about a 20

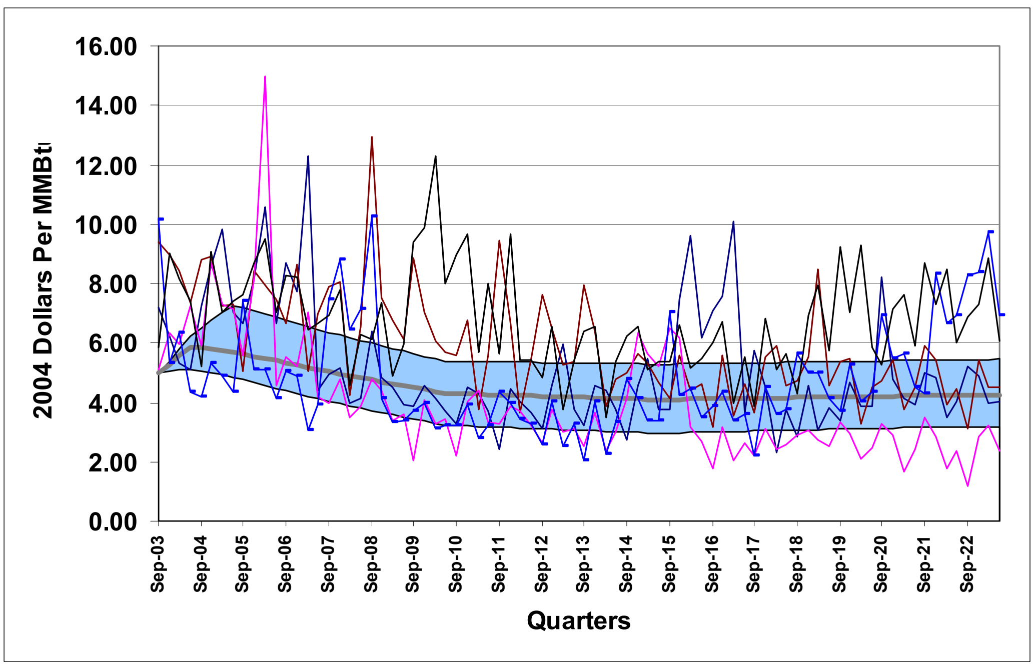



**Figure P-40: Quarterly Natural Gas Prices for Selected Futures**

percent chance of finding quarterly averages above the Council's high natural gas price forecast and a 20 percent chance of finding quarterly averages below the Council's low price forecast. The median of the price futures falls on top of the Council's median price forecast. This is all desirable behavior for these forecasts.

The results of the comparison of the regional model's natural gas price futures with the Council's forecasts are favorable. The only improvement on the regional model's representation that is evident after the fact is that, as has been the case in the past, the

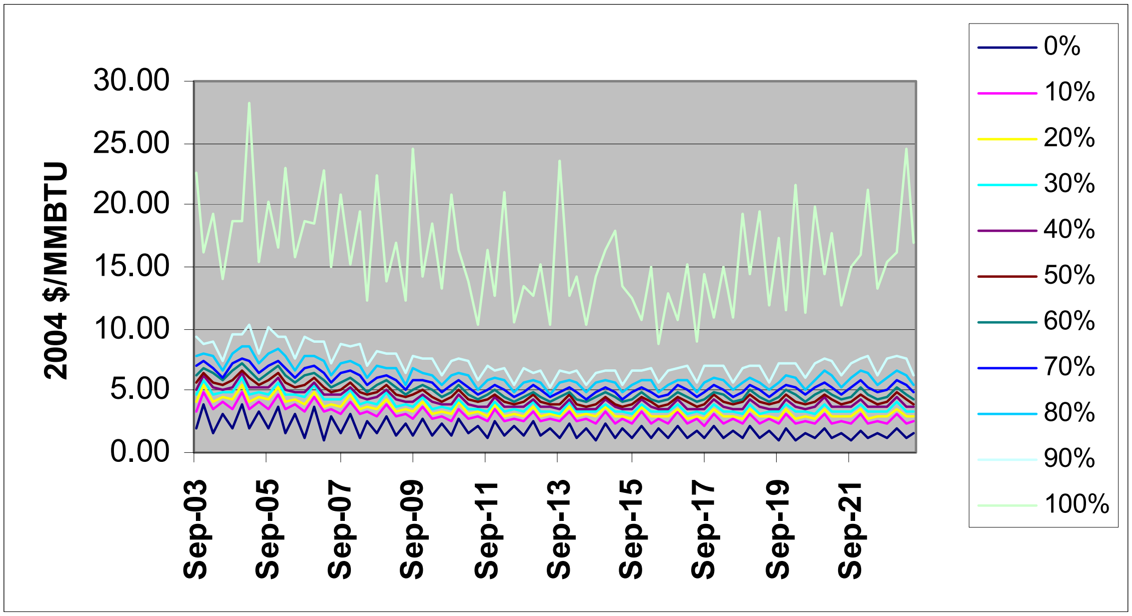



**Figure P-41: Deciles for Quarterly Natural Gas Price Futures**

Council's price forecasts may underestimate uncertainty. (See Figure P-7) This may be a difficult situation to improve. The intuition of experts determines the range of uncertainty; without behavior that is consistent with experts' intuition, the results of the model do not have credibility. Perhaps the best outcome will be one where *low probability ranges* are as wide as feasible.

## Hydro

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

The regional model assumes that most hydrogeneration is insensitive to price. Hydrogeneration already occurs primarily on peak for both economic and reliability purposes, as much as non-economic constraints permit. The regional model captures differences in on- and off-peak generation, as described below. Nevertheless, there often remains a relatively small amount of energy that operators can shift among months for commercial reasons, without adversely affecting the refill probabilities of the system. Appendix L describes how the regional model captures that behavior using reversible supply curves. (See the Appendix L section "Price-Responsive Hydro.") The scope of hydrogeneration modeling that this Appendix P discusses is the energy that is not responsive to price.

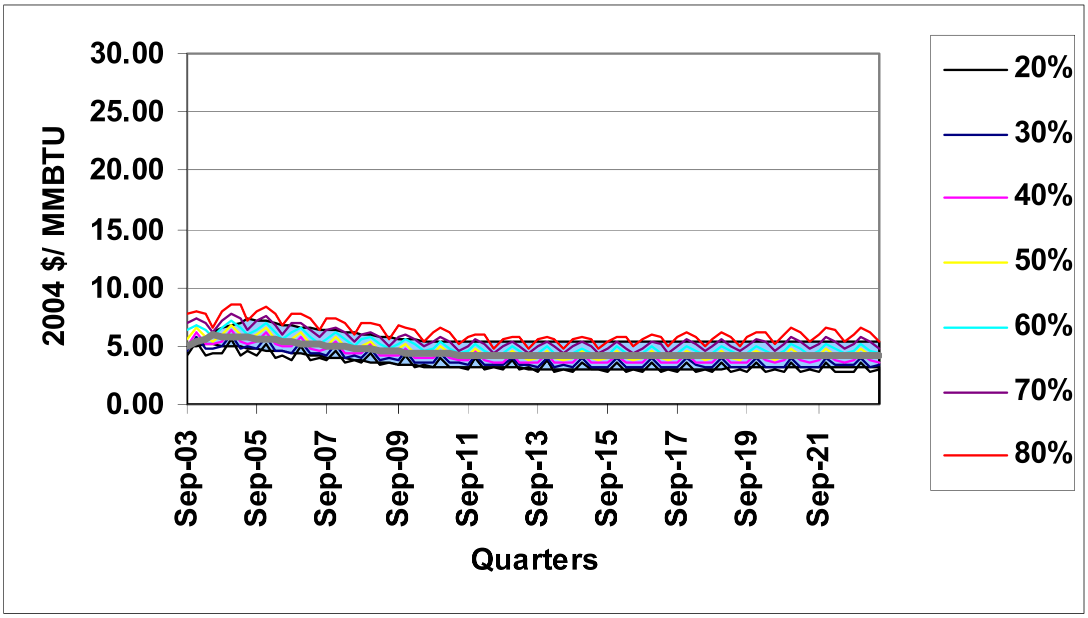



**Figure P-42: Correspondence of Council's Natural Gas Price Range to Futures' Deciles**

## Data Sources and Representation

The source of all data for the price-invariant hydrogeneration is a BPAREGU.OUT file [**10**]. The Council's GENESYS model, specifically the HYDREG subroutine, produces this file.[23] HYDREG is the monthly hydro regulator for Genesys, the same hydro regulator that BPA, the Northwest Power Pool, and Canada use for determining rights under the Pacific Northwest Coordination Agreement (PNCA). HYDREG produces monthly generation for each hydro generation project in the region for each of 50 years (hydro years 1929-1978) of stream flow conditions. Figure P-43 illustrates the output of HYDREG for a single month in 2001 under a single (1929) stream flow condition. As

[23] Genesys is available for download from the Council's website. Contact John Fazio or Michael Schilmoeller, Council staff (503-222-5161), for directions on acquiring, installing, and using the model.

explained below, HYDREG models more facilities than appear in Figure P-43, and a complete list of such facilities appears in Figure P-44 and Figure P-46.

The regional energy value reported at the top of Figure P-43, under the heading "FINAL," primarily determines the energy used in the regional portfolio model. However, not all facilities in Figure P-43 contribute to the "FINAL" value. There are three reasons why energy is not included. First, the facility may have no generation. An example is Columbia Falls *gage* ("COLFLS") in Montana, which is a constraint on the hydro regulator. Gages always have zero energy under the column "AVMW" in Figure P-43. In Figure P-44 and Figure P-46, these have the word "gage" included in their names.

The second reason a facility may not contribute to the "FINAL" energy is that the facility may be located in Canada. Their operation is critical to the regulator, but the unit obviously does not directly contribute to regional energy. Any dams located in Canada have an asterisk in Figure P-43. In Figure P-44 and Figure P-46, these have the expression "(CAN)" included in their names, and their location is CAN. The capacity, ownership, and regulation status of Canadian facilities does not appear in the latter figures.

The third reason a facility would not contribute to the "FINAL" energy is that the PNCA does not incorporate its generation. Three Idaho facilities, Brown Lee, Oxbow, and Hell's Canyon, are part of the region and are regulated, but are not under the PNCA. The names of these three facilities have an asterisk in Figure P-43, as well.

Another class of regional plants that *contribute* to the region's energy supply but *do not* contribute to the "FINAL" energy is unregulated or "independent" plants. These are run-of-river plants and dams with capacity that is so small that HYDREG ignores their regulation. The names of these plants do not appear in Figure P-43 but are in Figure P-44 and Figure P-46, along with ownership and location information. They appear with regulation status "unreg." The total generation for the independents, however, does appear under the heading INDP at the top of Figure P-43.

HYDREG knows whether the hydro generator is east or west of the Cascades, and it produces a separate subtotal for each area. A special Council application [**11**] parses the BPAREGU.OUT file and creates a simple table of regional hydro generation (average MW) for both the East side and the Westside of the Cascades, by month and by hydro condition. Because the regional portfolio model needs all regional generation, the parsing application uses the "FINAL" energy from the BPAREGU.OUT file, adds in the unregulated generation from the "INDP" field, and adds the generation of Brown Lee, Oxbow, and Hell's Canyon.

One subtlety to preparing the hydro generation data lies in extracting on- and off-peak power from the monthly average energies that HYDREG produces. For the regional model, the on-peak period is 6 a.m. to 10 p.m. Monday through Saturday. The remaining hours are off peak. (Western power operations professionals refer to this subperiod definition of 16 on-peak hours on the six days of the week as the 6x16 or "six by sixteen" standard.) Although HYDREG does not provide subperiod values for systems hydrogeneration, extensive studies of sustained peeking capability for the system provide some guidance.

For their fourth power plan, the Council commissioned Dr. Mike McCoy to make estimates of two-, four-, and 10-hour sustained peeking capability for the hydroelectric system.[24] An analysis of the conclusions from this study suggests that the peeking capability in average megawatts decreases roughly linearly with the number of hours of sustained capability [**12**]. With this assumption, the following equation relates on- and off-peak generation capability, using the 6x16 on-peak standard, to the average energy and 10-hour sustained peaking capability.

Let
$E_p$ denote the on - peak (6days x 16hours) power (MW)
$\hat{E}_p$ denote the sustained 10 - hour on - peak (5 weekdays) power (MW)
$\overline{E}$ denote the flat or average power over the entire week (MW)
X denote the average power (MW) over hours that do not contribute to 10 - hour sustained peak
then

$$\overline{E} = \frac{5 \times 10 \times \hat{E}_p + (7 \times 24 - 5 \times 10)X}{7 \times 24}$$

$$E_p = \frac{\text{(saturday peak)} + \text{(weekday sus peak)} + \text{(weekday non - sus peak)}}{\text{total peak hours}}$$

$$= \frac{16 \times X + 5 \times 10 \times \hat{E}_p + 5 \times 6 \times X}{(16 + 5 \times 10 + 5 \times 6)}$$

So solving for $X$ gives us

$$X = \frac{7 \times 24 \times \overline{E} - 5 \times 10 \times \hat{E}_p}{(7 \times 24 - 5 \times 10)} \text{ so}$$

$$E_p = \frac{5 \times 10 \times \hat{E}_p + (16 + 5 \times 6) \times X}{(16 + 5 \times 10 + 5 \times 6)}$$

which gives us on - peak power in terms of average power and 10 - hour, sustained peak power.

[24] Northwest Power Planning Council, "A Trapezoidal Approximation to the Pacific Northwest Hydropower System's Extended Hourly Peeking Capability Using Linear Programming," Appendix H 2, *Fourth Northwest Power Plan*.]

```
                     BPA REGULATOR OUTPUT FOR SEPTEMBER (PERIOD  1)     WATER YEAR 1929 STUDY YR 2001 GAME   1
                 2000 BIOLOGICAL OPINION - FSH027C Updated Spi

          DESIRED    FINAL     URC     ECC     PDP    XTRA1   XTRA2    INDP    PUMP       Draft Mode        ENER
EAST                 7582.   6327.   7482.   7582.   7582.  14079.    267.              User Draft Point  9.00
WEST                 1189.   1126.   1184.   1189.   1189.   1385.    400.
TOTAL    11615.   8771.   7453.   8665.   8771.   8771.  15464.    667.    137.

 PLANT   NO.  NAT Q  Q OUT   QMIN  FORCE  BYPAS  OTHER  OVERG I HKSM  AVMW   DRAFT ENDSTO  ELEV    URC    ECC    AER   CON VIOL
 -----  ---- ------  -----  -----  -----  -----  -----  ----- ------ -----  ------ ------ ------ ------ ------ ------  --- -- --
CUSH 1  2208    113   1390    100      0      0      0      0  49.08    26    38.3  149.1  718.5  171.3  161.5  149.1  FC
CUSH 2  2206    114   1391      0      0      0    100      0  30.59    43
ALDER   2190    450    683    300      0      0      0      0  20.25    14     7.0   74.4 1202.3   81.4   79.7   74.4  FC
LAGRND  2188    450    683      0    683      0      0      0   0.00    21
WHITE   2160    606    237    100      0      0    130      0  32.00     3   -11.1   20.9  540.9   23.5   21.4   20.9  FC
ROSS    2070   1047   2288    788      0      0      0      0  84.31    70    37.2  474.0 1592.5  530.5  482.3  473.9  QH  FC
DIABLO  2067   1613   2854      0      0      0      0      0  53.56    74
GORGE   2065   1759   3000   1500      0      0      0      0  27.06    87
U BAKR  2028   1030   1265      0      0      0      0      0  39.41    26     7.0   72.7  707.3  111.2   74.2   72.7  FC
L BAKR  2025   1220   1495     80      0      0      0      0  19.16    29     1.2   70.6  437.5   71.8   71.8   70.6  FC
MICA  * 1890  19310  19310  10000      0      0      0      0  84.62   834     0.0 5825.1 2470.1 5825.1 5825.0 5825.1  FC
REVELS* 1870  25280  25280      0      0      0      0      0  84.62   806     0.0  557.0 1875.6  557.0  557.0  557.0  FC
ARROW * 1831  36329  40642   5000      0      0      0      0  84.62     0   129.4 3450.2 1442.0 3579.6 3233.6 3450.2  FC
LIBBY   1760   5072   9656   4000      0      0    200      0 107.95   221   137.5 1923.8 2432.5 2510.5 1731.6 1923.8  PD  FG
BONFER  1740   6694  11279      0  11279      0      0      0  84.62     0
DUNCAN* 1681   2140   2973    100      0      0      0      0  84.62     0    25.0  680.8 1889.2  705.8  678.8  680.8  FC
CORA L* 1665  12270  13971   5000      0      0      0      0  84.62    21  -111.5  396.9 1745.3  396.9  396.9  396.9  FC
CANAL * 1664  12270   8971      0      0      0      0      0  84.62   177
UP BON* 1663  12270   5000      0      0      0      0      0  84.62    21
LO BON* 1660  12270   5000      0      0      0      0      0  84.62    23
S SLOC* 1658  12270   5000      0      0      0      0      0  84.62    25
BRILL * 1652  12197  13898      0      0      0      0      0  84.62    96
H HORS  1530    646   1419   1419      0      0      0      0 180.93    49    23.2 1290.0 3538.0 1549.0 1259.7 1290.0  QP  QL SL
COLFLS  1520   2727   3500   3500   3500      0      0      0 146.48     0
KERR    1510   3847   5083   3200      0      0      0      0 146.48    72    13.9  600.8 2892.8  614.7  575.4  600.8  FC
THOM F  1490   8840  10076   6000      0      0      0      0 132.37    45
NOXON   1480   6862   8098   3727      0      0      0      0 128.93    94     0.0  108.5 2329.0  116.3  108.5  108.5  FC
CAB G   1475   8136   9371   5000      0      0      0      0 117.27    65
PRST L* 1470    118      1      0      0      0      0      0 110.37     0    -3.5   25.0    2.1   35.5   26.0   25.0  FC
ALBENI  1465   9656  14665   4000      0      0     50      0 110.37    30   116.7  465.7 2060.0  582.4  465.7  465.7  FC
BOX C   1460   9806  14815      0      0      0      0      0 108.30    41
BOUND   1450   9939  14948      0      0      0      0      0 105.62   308
7-MILE* 1442  10206  15215      0      0      0      0      0  84.62   242
WANETA* 1440  10206  15215      0      0      0      0      0  84.62   244
CDA LK* 1341    704   1634    300      0      0      0      0 122.77     0    27.9   84.6 2126.6  112.5   86.9   84.6  FC
POST F  1340    704   1634    300      0      0      0      0 122.77     6
UP FLS  1332   1350   2280      0      0      0      0      0 118.92    10
MON ST  1330   1350   2280      0      0      0      0      0 115.92    13
NINE M  1315   1753   2683      0      0      0      0      0 105.45    11
LONG L  1305   2156   3092      0      0      0      0      0 101.70    36     0.2   50.1 1535.0   52.5   50.2   50.1  FC
L FALL  1302   2156   3092      0      0      0      0      0  89.97    16
COULEE  1280  56077  64261  50000      0      0      0      0  84.62  1574  -113.3 2329.7 1283.0 2614.3 2368.4 2329.7  PD
CH JOE  1270  56117  64301      0      0      0    500      0  60.12   822     0.0    0.0  953.8    0.0    0.0    0.0
WELLS   1220  58698  66882      0      0      0   1200      0  47.23   337
CHELAN  1210    647   1637     50      0      0      0      0  68.79    43    29.7  308.5 1098.0  341.5  308.3  308.5  FC
R RECH  1200  59404  68578      0      0      0      0      0  42.75   457
ROCK I  1170  61975  71149      0      0      0      0      0  36.08   209
WANAP   1165  62061  71235      0      0      0   2200      0  33.25   410
PRIEST  1160  62340  71514  36000      0      0   2200      0  27.60   413
BRNLEE*  767  14452  14452   5000      0      0      0      0  50.27   252     0.0  293.8 2045.0  491.7  411.2  293.8  PD
OXBOW *  765  14452  14452      0      0      0    100      0  50.27   112
HELL C*  762  14497  14497      0      0      0      0      0  50.27   215
DWRSHK   535   1060   1300   1300      0      0    100      0  93.13    51     7.2  388.6 1518.9  902.6  378.1  388.6  QL  SA
LR.GRN   520  22361  22600  11500      0      0    670      0  50.27   154     0.0  225.0  733.0  245.8   78.1  225.0  FC
L GOOS   518  22361  21783  11500      0      0    630      0  43.27   147   -24.5  285.0  638.0  285.0  128.6  285.0  UR  FC
LR MON   504  21657  20758  11500      0      0    750      0  36.30   142    -9.6  190.1  540.0  190.1   83.2  190.1  FC
ICE H    502  21647  20367   7500      0      0    740      0  29.20   137   -11.4  204.8  440.0  204.8   90.8  204.8  FC
MCNARY   488  79759  87654  50000      0      0   4000      0  22.23   458     0.0    0.0  338.7    0.0    0.0    0.0
J DAY    440  80738  88631  50000      0      0    800      0  16.76   664    -0.1  127.8  262.5  269.7  127.8  127.8  PD  FC
RND B    390   3154   3302   2800      0      0    200      0  47.09    81     4.4  131.9 1941.7  138.3  135.5  131.9  FC
PELTON   388   3354   3502   3000      0      0      0      0  21.10    33
REREG    387   3354   3502      0      0      0      0      0  11.74     8
DALLES   365  84499  92540  50000      0      0   4300      0   9.20   540
BONN     320  87725  95766      0      0      0   8400      0   4.86   424     0.0    0.0   74.1   -1.0    0.0    0.0  PL  UR
TMTHY    117     87    177     10      0      0      0      0  86.88     0     2.7   28.4 3186.1   31.1   29.2   28.4  FC
OK GRV   115    344    434      0      0      0      0      0  86.88    27
NFORK    111    822    912      0      0      0      0      0  23.89     9
FRDAY    110    822    912      0      0      0      0      0  13.99     8
R MILL   108    822    912      0      0      0      0      0   5.10     5
SWFT 1    82    715    555      1      0      0      0      0  69.69    16    -4.8  219.4  997.2  225.4  225.4  219.4  FC
SWFT 2    80    715    555      0      0      0      0      0  40.59     5     0.0    0.0  603.0    0.0    0.0    0.0  FC
YALE      78    837    561      0      0      0      0      0  32.34    10    -3.5   93.1  488.7   95.6   95.6   93.1  FC
MERWIN    76    933   1475    800      0      0      0      0  13.77    20    24.6   62.4  224.4   92.1   63.2   62.4  FC
PCKW L*   63     56     56     10      0      0      0      0  40.54     0     0.0    0.0 2850.5    1.4    0.0    0.0  FC
MOSSYR    48   1194   3957   2858      0      0      0      0  40.54   103    82.9  566.3  763.0  654.3  654.3  566.3  FC
MAYFLD    42   1336   4099   3000      0      0      0      0  14.63    57
------------------------------------------------------------------------------------------------------------------------------
                           RESULTS FOR SEPTEMBER  (PERIOD  1)     WATER YEAR 1929          INTERLACE PERIOD    3

PHASE                DESIRED  ACTUAL = (REGUL  + INDEP   - PUMP)    SPILL   MICA+RVL  DRAFT PT    DRAFT
------------------      MW       MW       MW       MW       MW       MW       MW                  MW-MO
PROPORTIONAL DRAFT  12145.0   9300.8   8770.8    667.0    137.0       0.           6.000000
MICA NON-TRTY (BC)   1046.1      0.0      0.0                         0.       0.  MAX STORE    0  MAX RETURN    0
MICA NON-TRTY (US)   1020.8      0.0      0.0                         0.       0.  MAX STORE    0  MAX RETURN    0
ALLOCATE SPILL                   0.0      0.0                         0.
FINAL OPERATION     12145.0   9300.8   8770.8    667.0    137.0       0.                          7419.
ENERGY CONTENT (MW-MO) RELATIVE TO TARGET  54683. 33 PLANTS ABOVE BY  54683.     0 BELOW BY      0.
ENERGY CONTENT (MW-MO) RELATIVE TO ECC   1807.  TO PDP(AER)      0.
THE DALLES FLOW AT URC=      0.  ECC=      0.  TREATY=  92540.  FINAL=  92540.
```

**Figure P-43: Sample from a BPA HYDSIM Regulator BPARegu.out file**

| Name | Cap (MW) | ownership | regulated | location |
|---|---|---|---|---|
| Albeni Falls | 43 | Fed | Reg | OR/WA |
| Alder | 50 | Non-Fed | Reg | OR/WA |
| American Falls | 92 | Non-Fed | Unreg | ID |
| Anderson Ranch | 40 | Fed | Unreg | ID |
| Arrow (CAN) | | | | CAN |
| Big Cliff | 18 | Fed | Unreg | OR/WA |
| Big Creek (Flathead Irr Prj, MT) | 1 | Non-Fed | Unreg | MT |
| Black Canyon | 10 | Fed | Unreg | ID |
| Bliss | 75 | Non-Fed | Unreg | ID |
| Boise Diversion (USBR) | 2 | Fed | Unreg | ID |
| Bonners Ferry gage | | | | ID |
| Bonneville | 1093 | Fed | Reg | OR/WA |
| Boundary | 951 | Non-Fed | Reg | OR/WA |
| Box Canyon (PEND) | 60 | Non-Fed | Reg | ID |
| Brill (CAN) | | | | CAN |
| Brownlee | 585 | Non-Fed | Reg | ID |
| Bull Run (PGE) | 21 | Non-Fed | Unreg | OR/WA |
| C.J. Strike | 83 | Non-Fed | Unreg | ID |
| Cabinet Gorge | 222 | Non-Fed | Reg | ID |
| Calispel Creek | 1 | Non-Fed | Unreg | ID |
| Canal (CAN) | | | | CAN |
| Carmen Smith | 90 | Non-Fed | Unreg | OR/WA |
| Cascade (IDPC) | 12 | Non-Fed | Unreg | ID |
| Cedar Falls (SCL) | 20 | Non-Fed | Unreg | OR/WA |
| Chandler | 12 | Fed | Unreg | OR/WA |
| Chelan | 48 | Non-Fed | Reg | OR/WA |
| Chief Joseph | 2457 | Fed | Reg | OR/WA |
| City of Idaho Falls | 42 | Fed | Unreg | ID |
| Clear Lake (IDPC) | 3 | Non-Fed | Unreg | ID |
| Clearwater 1,Clearwater 2 | 41 | Non-Fed | Unreg | OR/WA |
| Coeur D'Alene Lake gage | | | | ID |
| Columbia Falls gage | | | | MT |
| Condit | 10 | Non-Fed | Unreg | OR/WA |
| Copco 1 | 20 | Non-Fed | Unreg | OR/WA |
| Copco 2 | 27 | Non-Fed | Unreg | OR/WA |
| Corra Linn (CAN) | | | | CAN |
| Cougar | 25 | Fed | Unreg | OR/WA |
| Cowlitz Falls (Lewis Co PUD) | 70 | Non-Fed | Unreg | ID |
| Cushman 1 | 43 | Non-Fed | Reg | OR/WA |
| Cushman 2 | 81 | Non-Fed | Reg | OR/WA |
| Dalles | 1807 | Fed | Reg | OR/WA |
| Detroit | 100 | Fed | Unreg | OR/WA |
| Dexter | 15 | Fed | Unreg | OR/WA |
| Diablo | 123 | Non-Fed | Reg | OR/WA |
| Duncan (CAN) | | | | CAN |
| Dworshak | 400 | Fed | Reg | ID |
| Electron | 26 | Non-Fed | Unreg | OR/WA |
| Faraday | 35 | Non-Fed | Reg | OR/WA |
| Fish Creek | 11 | Non-Fed | Unreg | OR/WA |
| Foster | 20 | Fed | Unreg | OR/WA |
| Gorge (SCL) | 207 | Non-Fed | Reg | OR/WA |
| Grand Coulee | 6494 | Fed | Reg | OR/WA |
| Green Peter | 80 | Fed | Unreg | OR/WA |
| Green Springs | 16 | Non-Fed | Unreg | OR/WA |
| Hells Canyon | 392 | Non-Fed | Reg | ID |
| Henry M Jackson (Snohomish PUD) | 112 | Non-Fed | Unreg | OR/WA |
| Hills Creek | 30 | Fed | Unreg | OR/WA |
| Hungry Horse | 428 | Fed | Reg | MT |
| Ice Harbor | 603 | Fed | Reg | OR/WA |
| Iron Gate | 18 | Non-Fed | Unreg | OR/WA |
| Island Park Hydroelectric Proj | 5 | Fed | Unreg | ID |
| John C Boyle | 80 | Non-Fed | Unreg | OR/WA |
| John Day | 2160 | Fed | Reg | OR/WA |
| Kerr | 168 | Non-Fed | Reg | MT |
| La Grande | 64 | Non-Fed | Reg | OR/WA |
| Leaburg | 14 | Non-Fed | Unreg | OR/WA |
| Lemolo units 1& 2 | 62 | Non-Fed | Unreg | OR/WA |
| Libby - USCEPD | 525 | Fed | Reg | MT |

**Figure P-44: Facilities Contributing to Hydrogeneration (1/2)**

Off-peak (168-6x16) hours are a subset of the hours to which *X* pertains. Therefore, the off-peak power is exactly *X*. The sustained peaking information is from reference [**13**], which provides relationships between 2-, 4-, and 10-hour sustained peak capacity as a function of system energy for each month.

The special Council application [**14**] that parses the BPAREGU.OUT file uses the appropriate number of on- and off-peak hours for each month to estimate average on- and off-peak power (MW). For the regional model, another Council application reduces these data to hydro year quarters [**15**].

## Worksheet Function and Formulas

Turning to the worksheet function that provides this data to the regional model, we note that several versions of the function exist and are available to the public. One of these, for example, is an Excel add-in that provides monthly energies in both megawatt-hours and average energy, on peak and off peak, as well as sustained, 10-hour peak generation for the region, for each stream flow condition, and separately for or combined east and west of the Cascades. The version used in the regional portfolio model, however, is not an Excel add-in, but instead a VBA function that reads a worksheet ("For AddIn ver 7") of data.[25] This section returns shortly to the description of this function.

The regional model uses hydrogeneration for three purposes, meeting energy requirements, influencing electricity price, and for planning long-term resource requirements. The influence on electricity price is discussed in the following section, "Electricity Price." For planning long-term resource requirements, the model uses critical hydrogeneration levels, which the model assumes remain constant. Consequently, this section outlines only the use of hydrogeneration for meeting energy requirements.

The discussion of hydrogeneration in Appendix L refers to the on-peak average MWh hydrogeneration in a specific, but representative cell, {AQ 36} in the example workbook L24DW02-f06-P.xls. (This is identical to cell {{AQ 36}} in L28_P.xls.) The on-peak calculation in {{AQ 36}} is

=(AQ33-300*AP$21/79)*1152

This differs from the formula in {AQ 36}, "=AQ33*1152," in the draft plan workbook. Between the draft and final plan, the Council added a loss of hydroelectric availability over the twenty years of the study. The beginning of this section describes the reasons for this loss. The loss is deterministic and increases linearly with time to 300MWa by the end of the study. Incorporating that loss is what the additional term -300*AP$21/79 achieves.

---

[25] The use of Excel add-ins complicates the use of distributed computing with Decisioneering, Inc.'s CB Turbo®, described in Appendix L. Each machine would have to be equipped with a copy of the add-in, so changing any logic in the add-in becomes burdensome.

The cell {{AQ 33}} references the VBA function that provides average MW for the period:

=vfuncHydro4x2W($R$24:$CS$24,1)

VBA function vfuncHydro4x2W takes as its first argument a range containing cells that assume random, real values – one for each hydro year – between 0.0 and 50.0. In the preceding example of {{AQ 33}}, the range is $R$24:$CS$24. These real numbers determine the stream flow condition for the hydro year (September through August of the following year). We return to this determination in a moment.

After the range, the function takes integer that specifies the subregion for which hydrogeneration is requested. A zero designates hydrogeneration for east of the Cascades; the one in {{AQ 33}} designates hydrogeneration west of the Cascades.

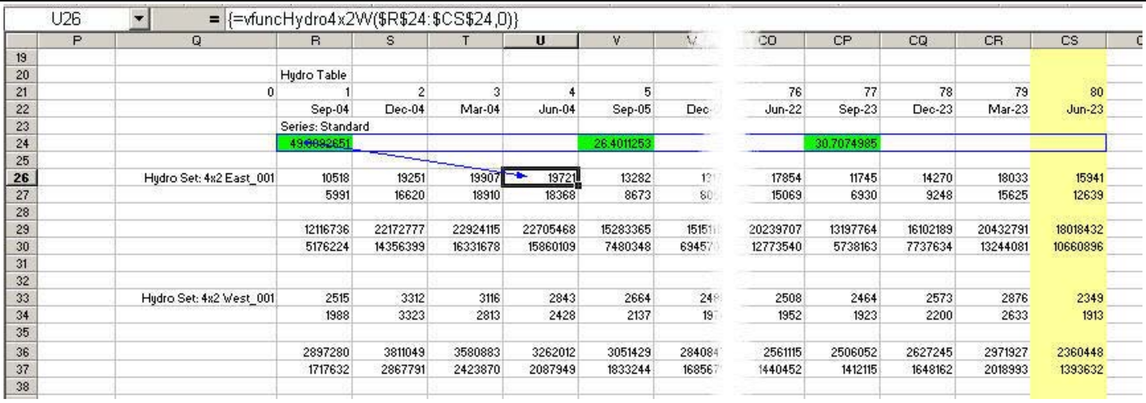
The function returns a range two rows high and 80 columns wide, in the case of the regional model. The range contains cells with the hydrogeneration (MWa) for that subregion, for each period (column). The first row contains on-peak hydrogeneration; the second row contains off-peak hydrogeneration.

It may be helpful to examine the VBA function vfuncHydro4x2W from a couple of perspectives. The definition of the vfuncHydro4x2 function is as follows

```
Function vfuncHydro4x2(ByRef rYears As Range, ByVal lLoc As Long, Optional
        ByVal, lStartPeriod As Long = 0) As Variant

Takes:
rYears - Range, pointing to a vector of single [0.00-50.00] representing the years 1929-
        1978, sorted ascending by annual energy. For example, the user can have Excel
        pass 50 * rand() as sYear to this function to get draws of hydro condition.
        Ascending order permits user to correlate annual energy with other variable.  To
        access a particular year, use the sfuncYear() function, below.

lLoc - 0, East only
       1, West only
       2, East+West Generation

lStartPeriod - Optional'
       0, (default), Range of returned energies starts with Sep - Nov
       1, Dec - Feb
       2, Mar - May
       3, Jun - Aug
==============================================================
Returns:
       A variant containing an array of period Hydrogeneration (MWa) for east-side or
       west-side generation, or both.  The value of each element of the array corresponds
       to the value of the hydro year choice, for the appropriate region and subperiod
```

For a different perspective on what this function is doing, consider the auditing references in Figure P-45. The average MW of generation in cell {{U26}} is one entry of a range, {{R26:CS27}}, which the function is returning. The value of {{U26}} is the on-peak hydrogeneration East of the Cascades for a particular hydro year. For which hydro year does the function return generation? The function is returning the fourth quarter for the first hydro year, so it uses the random number a the beginning of the hydro year, cell {{R24}} from the input range {{$R$24:$CS$24}}.

To what historical hydro year do the values correspond? In Figure P-45, the random number in cell {{R24}} has the value 49.38926508. There are 50 years of hydrogeneration data. The generation returned is for the year, according to the rank by



U26 = {=vfuncHydro4x2W($R$24:$CS$24,0)}

| | P | Q | R | S | T | U | V | W | CO | CP | CQ | CR | CS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | | | | | | | | | | | | | |
| 20 | | | Hydro Table | | | | | | | | | | |
| 21 | | 0 | 1 | 2 | 3 | 4 | 5 | | 76 | 77 | 78 | 79 | 80 |
| 22 | | | Sep-04 | Dec-04 | Mar-04 | Jun-04 | Sep-05 | Dec | Jun-22 | Sep-23 | Dec-23 | Mar-23 | Jun-23 |
| 23 | | | Series: Standard | | | | | | | | | | |
| 24 | | | 49[illegible]2651 | | | | 26.4011253 | | | 30.7074985 | | | |
| 25 | | | | | | | | | | | | | |
| 26 | | Hydro Set: 4x2 East_001 | 10518 | 19251 | 19907 | 19721 | 13282 | [illegible] | 17854 | 11745 | 14270 | 18033 | 15941 |
| 27 | | | 5991 | 16620 | 18910 | 18368 | 8673 | [illegible] | 15069 | 6930 | 9248 | 15625 | 12639 |
| 28 | | | | | | | | | | | | | |
| 29 | | | 12116736 | 22172777 | 22924115 | 22705468 | 15283365 | [illegible] | 20239707 | 13197764 | 16102189 | 20432791 | 18018432 |
| 30 | | | 5176224 | 14356399 | 16331678 | 15860109 | 7480348 | [illegible] | 12773540 | 5738163 | 7737634 | 13244081 | 10660896 |
| 31 | | | | | | | | | | | | | |
| 32 | | | | | | | | | | | | | |
| 33 | | Hydro Set: 4x2 West_001 | 2515 | 3312 | 3116 | 2843 | 2664 | [illegible] | 2508 | 2464 | 2573 | 2876 | 2349 |
| 34 | | | 1988 | 3323 | 2813 | 2428 | 2137 | [illegible] | 1952 | 1923 | 2200 | 2633 | 1913 |
| 35 | | | | | | | | | | | | | |
| 36 | | | 2897280 | 3811049 | 3580883 | 3262012 | 3051429 | [illegible] | 2561115 | 2506052 | 2627245 | 2971927 | 2360448 |
| 37 | | | 1717632 | 2867791 | 2423870 | 2087949 | 1833244 | [illegible] | 1440452 | 1412115 | 1648162 | 2018993 | 1393632 |
| 38 | | | | | | | | | | | | | |

**Figure P-45: Hydro Function References**

annual hydrogeneration energy, for lowest to highest. For example, the random number 49.38926508 lies in the last bin, (49,50], so the year with the highest annual hydrogeneration would be returned, in this case hydro year 1973-1974. If the random number had been 0.5 on the other hand (or any number less than 1.0), the function would return the driest year on record, 1931, as determined by total annual generation.

A separate function simplifies the process of getting data for a particular hydro year. The regional model does not use the function sfuncYear, but the Council would make it available to any party on request. It returns a real number corresponding to each hydro year that the vfuncHydro4x2 function returns. Its definition follows.

```
Function sfuncYear(ByVal lYear As Long, ByVal lType As Long) As Single
Takes a calendar year, e.g., 1937, and returns a real single with a value in the middle of
        the correct "bin" for that year, for use as input to vfuncHydroGen. For example,
        1937 is the second lowest year for Eastside Hydro, in terms of annual energy
        and is therefore the second entry in vfuncHydroGen(*,0).  Then
        sfuncYear(1937,0) = 1.5  (The first bin is [0,1), the second is [1,2), etc.

lYear - calendar year, as long
lType - 0, East Generation only
        1, West Generation only
2, East+West Generation
```

This concludes the description of the model worksheet VBA function. This section next considers the assumed hourly behavior of hydrogeneration.

| Name | Cap (MW) | ownership | regulated | location |
|---|---|---|---|---|
| Little Falls (WWPC) | 32 | Non-Fed | Reg | OR/WA |
| Little Goose | 810 | Fed | Reg | OR/WA |
| Long Lake | 70 | Non-Fed | Reg | OR/WA |
| Lookout Point | 120 | Fed | Unreg | OR/WA |
| Lost Creek | 49 | Fed | Unreg | OR/WA |
| Lower Baker | 64 | Non-Fed | Reg | OR/WA |
| Lower Bonnington (CAN) | | | | CAN |
| Lower Granite | 810 | Fed | Reg | OR/WA |
| Lower Malad | 14 | Non-Fed | Unreg | ID |
| Lower Monumental | 810 | Fed | Reg | OR/WA |
| Lower Salmon | 60 | Non-Fed | Unreg | ID |
| Mayfield | 162 | Non-Fed | Reg | OR/WA |
| McNary | 980 | Fed | Reg | OR/WA |
| Merwin | 136 | Non-Fed | Reg | OR/WA |
| Mica (CAN) | | | | CAN |
| Mill Creek | 1 | Fed | Unreg | OR/WA |
| Milner (IDPC) | 59 | Non-Fed | Unreg | ID |
| Minidoka | 8 | Fed | Unreg | ID |
| Monroe Street | 15 | Non-Fed | Reg | OR/WA |
| Mossyrock | 300 | Non-Fed | Reg | OR/WA |
| Nine Mile | 26 | Non-Fed | Reg | OR/WA |
| North Fork | 38 | Non-Fed | Reg | OR/WA |
| Noxon Rapids | 467 | Non-Fed | Reg | MT |
| Oak Grove | 51 | Non-Fed | Reg | OR/WA |
| Oxbow (IDPC) | 190 | Non-Fed | Reg | ID |
| Packwood | 30 | Non-Fed | Unreg | OR/WA |
| Packwood Lake gage | | | | OR/WA |
| Palisades (USBRCO) | 177 | Fed | Unreg | ID |
| Pelton | 97 | Non-Fed | Reg | OR/WA |
| Pelton Re-Regulation | 18 | Non-Fed | Reg | OR/WA |
| Post Falls | 15 | Non-Fed | Reg | OR/WA |
| Priest Lake gage | | | | OR/WA |
| Priest Rapids | 923 | Non-Fed | Reg | OR/WA |
| Prospect units 1-4 | 44 | Non-Fed | Unreg | OR/WA |
| Revelstoke (CAN) | | | | CAN |
| River Mill | 19 | Non-Fed | Reg | OR/WA |
| Rock Island Powerhouse | 624 | Non-Fed | Reg | OR/WA |
| Rocky Reach | 1280 | Non-Fed | Reg | OR/WA |
| Ross Dam | 360 | Non-Fed | Reg | OR/WA |
| Round Butte | 247 | Non-Fed | Reg | OR/WA |
| Roza | 13 | Fed | Unreg | ID |
| Seven Mile (CAN) | | | | CAN |
| Shoshone Falls | 13 | Non-Fed | Unreg | ID |
| Slide Creek | 18 | Non-Fed | Unreg | OR/WA |
| Smith Creek (EWEB) | 38 | Non-Fed | Unreg | OR/WA |
| Snoqualmie | 42 | Non-Fed | Unreg | OR/WA |
| Soda Springs | 11 | Non-Fed | Unreg | OR/WA |
| South Slocan (CAN) | | | | CAN |
| Stone Creek (EWEB) | 12 | Non-Fed | Unreg | OR/WA |
| Strawberry Creek (Lower Valley P&L) | 2 | Non-Fed | Unreg | ID |
| Swan Falls | 25 | Non-Fed | Unreg | ID |
| Swift 1 | 204 | Non-Fed | Reg | OR/WA |
| Swift 2 | 70 | Non-Fed | Reg | OR/WA |
| T.W. Sullivan | 15 | Non-Fed | Unreg | OR/WA |
| Thompson Falls (MPC) | 93 | Non-Fed | Reg | MT |
| Thousand Springs | 9 | Non-Fed | Unreg | ID |
| Timothy Lake gage | | | | OR/WA |
| Toketee Falls | 43 | Non-Fed | Unreg | OR/WA |
| Trail Bridge (EWEB) | 10 | Non-Fed | Unreg | OR/WA |
| Twin Falls (IDPC) | 44 | Non-Fed | Unreg | ID |
| Upper Baker | 105 | Non-Fed | Reg | OR/WA |
| Upper Bonnington (CAN) | | | | CAN |
| Upper Falls (WWP) | 10 | Non-Fed | Reg | OR/WA |
| Upper Malad | 8 | Non-Fed | Unreg | ID |
| Upper Salmon Falls | 35 | Non-Fed | Unreg | ID |
| Wanapum | 1038 | Non-Fed | Reg | OR/WA |
| Waneta (CAN) | | | | CAN |
| Wells (DOPD) | 774 | Non-Fed | Reg | OR/WA |
| White River (PSPL) | 70 | Non-Fed | Reg | OR/WA |
| Yale | 108 | Non-Fed | Reg | OR/WA |
| Yelm (Centralia) | 10 | Non-Fed | Unreg | OR/WA |

**Figure P-46: Facilities Contributing to Hydrogeneration (2/2)**

### Hourly Behavior

Recall that there are two types of hydrogeneration in the regional model, the type that this section discusses, which does not respond to electricity market prices, and the market-price responsive type. Appendix L has a description of how the regional model captures the latter at the time step of a hydro year quarter. (See pages L-48 and L-106.)

At the hourly time step, there is certainly a difference for non-price responsive hydrogeneration on- and off-peak. Because the function vfuncHydro4x2W already accounts for these differences through separate returned values, however, the question of any remaining variation means variation *within* the respective subperiods. If there is any such residual variation in hydrogeneration, the model assumes it is small and uncorrelated with electricity price. The hydrogeneration valuation calculations in the model therefore implicitly assume a zero correlation between hourly hydrogeneration and hourly electricity market price. (See page L-50.)

## Electricity Price

Many forecasters use long-term equilibrium price models to estimate future electric power prices. These models result in annual average electricity prices that equal the fully allocated cost of the plant used for expanding system capacity, which in the West is typically a combined-cycle combustion turbine (CCCT). While useful to understanding price trends, these models ignore the disequilibrium between supply and demand that is commonplace for electricity. Disequilibrium results from less than perfect foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last as long as it takes for new capacity to be constructed or released, or surplus capacity to be retired or "grown into." Resulting excursions from equilibrium prices can be large and are a significant source of uncertainty to electric power market participants. Because it is very difficult for an individual utility to exactly match loads and its own resources at all times, virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so when the region's primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

To capture these effects, the regional model must incorporate correlation of electricity prices with hydropower availability, loads, and natural gas prices. Correlation between electricity prices and load on the time scale of the hydro quarter should have the opposite sign of the correlation on the time scale of years. That is, demand elasticity of loads needs attention.

In addition, market prices must reflect changes in available generation relative to load. For a given load, additional generation tends to drive down electric power prices. In particular, if generation would initially exceed requirements, plus the region's ability to export, prices will be reduced until generation equals loads plus export capability. Similarly, if generation is inadequate to meet requirements, given the region's import capability, prices will increase until the situation is resolved, e.g., loads are reduced or the price induces sufficient generation.

Finally, electricity prices also exhibit substantial random variations due to conditions in other parts of the interconnected West and other factors that are not explicitly considered. These other factors include, for example, regulatory and legislative innovations and the introduction of new generation technologies.

This section begins with an overview of the construction of electricity prices in the regional model. It describes how the model accommodates the requirements just mentioned. The treatment addresses price averages at the time scale of the hydro quarter-year. The model uses electricity prices for energy requirement valuation, as input to various decision criteria, and for producing load elasticity, and the section explores those in turn. The section then traces the formulas in the sample Excel workbook portfolio model from the point where the discussion of Appendix L, "The Portfolio Model" leaves off. Finally, it elaborates on some of the hourly price behavior, which typically is different from that at the time scale of the hydro quarter.

## Background

At its December 19, 2002, meeting, the Council's System Analysis Advisory Committee (SAAC) discussed the influence that various sources of uncertainty have on each other. Figure P-47 resembles the Influence Diagram that the SAAC used. Most of the influences are predictable. As hydro generation increases, for example, electricity prices should decrease. In the short term, increases in load, natural gas prices, and forced outages should push up the price of electricity.

There are hosts of factors besides regional hydro generation, load requirements, natural gas prices, and forced outage rates, however that influence regional electricity prices. (For brevity, we will refer to regional hydro generation, load requirements, natural gas prices, and forced outage rates as the "local variables" in the following.) First, the values of local variables do not capture the corresponding influences from outside the region. For example, economic recession and load reduction in California or the Pacific Southwest would probably have the effect of depressing electricity prices in the Pacific Northwest. Second, there are certainly factors that influence electricity price besides the four just identified. Over the long-term, technology innovation could easily trump the influence of these four. Unanticipated changes in legislation or the regulation of electricity could influence the availability of supply both within the region and outside the region. Changes in supply availability from outside what we traditionally think of as the region is another factor. Examples of these influences are regional Independent Power Producers (IPP) and California's initiative to implement a strong reserve margin. While it might be possible to model these individual factors explicitly, a surrogate for these effects is an unanticipated excursion in electricity price that is independent of the local variables. That is, such excursions are the primary means by which supply outside the traditional region's system influences regional costs.

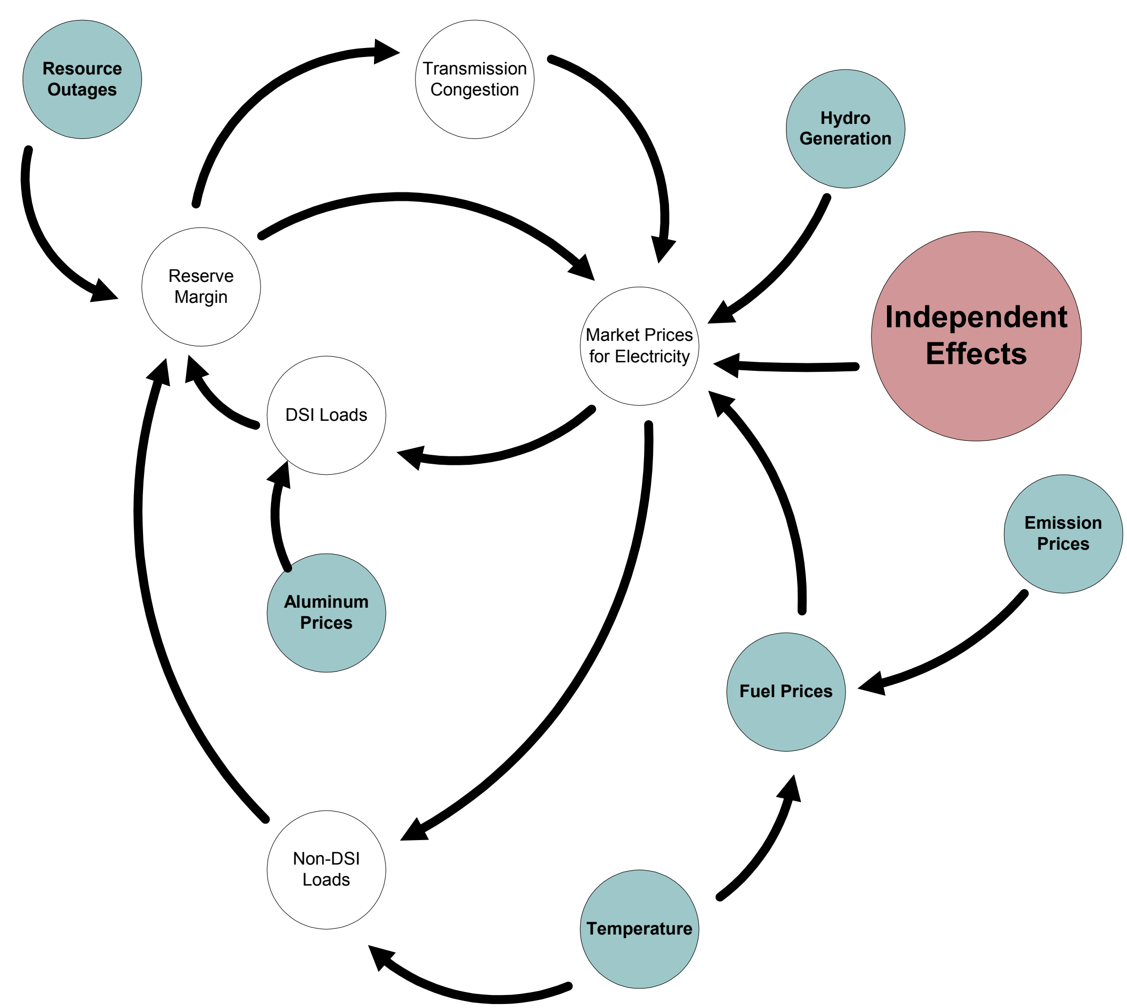



**Figure P-47: Independent Term**

The Council used Bench Mark Heuristics (BMH) to study the statistical behavior of electricity prices, transmission, load requirements, natural gas prices, hydro generation, and a host of other related data [**16**]. BMH studied each of the factors individually, and created a detailed regression model for each, using an ARMA process to simulate the error term. BMH then modeled the relationship between local electricity prices and local loads, natural gas prices, and hydro generation, seasonal, and weekday factors. Based on the best explanatory model BMH produced, local variables explain only about 43 percent of the change in daily electricity prices [**17**]. When markets are in transition, the influence of these local variables is even smaller. There is a significant amount of variation in electricity price behavior that local variables do not explain. Figure P-47 illustrates the influence of such Independent Effects with a conspicuous bubble.

Both local and independent effects, of course, work together to produce the final electricity prices. For modeling purposes, however, we conceive of these influences as follows. If in every period, loads and other local variables had "normal" values, what remained would be a path of electricity prices that must be the result of the independent effects. (The influence of independent effects, of course, could differ from "normal" conditions for all the reasons articulated in the previous paragraph.) To construct an electricity price series, therefore, it is valid to reverse this process. That is, it should be reasonable to apply the influence of loads, hydro generation, and a natural gas price to values representing the Independent Effect to obtain the resulting electricity price.

Unfortunately, we are not quite finished, because we may still need to adjustment for any energy imbalance. The section "The Influence of Resource-Load Imbalances" below, beginning on page P-74, discusses this adjustment issue.

The process just described is the one that the regional model uses to produce electricity price series. The next discussion focuses on the construction of the prices associated with Independent Effects. The subsequent discussion outlines the incorporation of influences for local hydro, load requirements, and natural gas prices. Forced outages influence prices to the extent that they affect energy imbalance.

The Independent Term for Electricity Price

The model constructs the Independent Effect for electricity price in a manner very similar to the way it constructs natural gas prices and loads. See the section, "Stochastic Process Theory," above for details. Underlying strategic paths for average price[26] are the sum of principal factors, jumps, and optionally a stochastic adjustment. (The final regional model does not make use of the stochastic adjustment.) The model applies this path separately to on- and off-peak prices from the Council's long-term, electricity equilibrium price forecast to obtain corresponding prices for the regional model.

The principal factors appear in Figure P-48. The model permits up to two jumps, and the values and formulas for those jumps appear in Figure P-49. Both principal factors and jumps, in turn, rely on stochastic variables in assumption cells, the data for which appear in Figure P-50. The values for all of these objects ultimately originate from SAAC and Council staff judgments about what seem to be realistic and feasible futures. (See the section "Model Validation," above.)

**Pricipal Factors**

| | offset | linear |
|---|---|---|
| | Weight | |
| | 1.000 | 1.000 |
| Dec of Cal | | |
| Year | Value | |
| 2003 | 0.50 | 0.07 |
| 2004 | 0.50 | 0.14 |
| 2005 | 0.50 | 0.21 |
| 2006 | 0.50 | 0.28 |
| 2007 | 0.50 | 0.35 |
| 2008 | 0.50 | 0.42 |
| 2009 | 0.50 | 0.49 |
| 2010 | 0.50 | 0.56 |
| 2011 | 0.50 | 0.63 |
| 2012 | 0.50 | 0.70 |
| 2013 | 0.50 | 0.77 |
| 2014 | 0.50 | 0.84 |
| 2015 | 0.50 | 0.91 |
| 2016 | 0.50 | 0.98 |
| 2017 | 0.50 | 1.05 |
| 2018 | 0.50 | 1.12 |
| 2019 | 0.50 | 1.19 |
| 2020 | 0.50 | 1.26 |
| 2021 | 0.50 | 1.33 |

source: L28_P.xls

**Figure P-48: Principal Factors for the Independent Component of Electricity Price**

[26] Here average price refers to period (hydro quarter) average, across on- and off-peak hours. This is synonymous with "flat" market prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

| | R | S | T |
|---|---|---|---|
| 99 | 29.35806 | 0.409331 | 11.08000719 |
| 100 | 22.56537 | 0.26246 | 10.60643151 |

| Cell | Formula | | interpretation |
|---|---|---|---|
| R101 | =$R$99 | wait_1 | start time of jump 1 |
| S101 | =R101+ IF($S$99= 0,0,12/$S$99) | wait_1+ 12/size_1 | end time of jump 1 |
| T101 | =$S$99 | size_1 | size_log xfr jump 1 |
| U101 | =S101 | end time of jump 1 | start time of recovery 1 |
| V101 | =U101+ S101*EXP(T101) | end time of jump 1 + duration recovery 1 | end time of recovery 1 |
| W101 | =-T101/10 | -size_1/10 | size_log xfr recovery 1 |
| X101 | =V101+ $R$100 | end time of recovery 1+ wait_2 | start time of jump 2 |
| Y101 | =X101+ IF($S$100= 0,0,12/$S$100) | wait_2 + 12/size_2 | end time of jump 2 |
| Z101 | =$S$100 | size_2 | size_log xfr jump 2 |
| AA101 | =Y101 | end time of jump 2 | start time of recovery 2 |
| AB101 | =AA101+ Y101*EXP(Z101) | end time of jump 2 + duration recovery 2 | end time of recovery 2 |
| AC101 | =-Z101/10 | -size_2/10 | size_log xfr recovery 2 |

| | | | |
|---|---|---|---|
| R102 | = IF(AND(R$46>$R101,R$46<=$S101),$T101,0)+ | jump_1 | source: L28_P.xls |
| | IF(AND(R$46>$U101,R$46<=$V101),$W101,0)+ | recovery_1 | |
| | IF(AND(R$46>$X101,R$46<=$Y101),$Z101,0)+ | jump_2 | |
| | IF(AND(R$46>$AA101,R$46<=$AB101),$AC101,0) | recovery_2 | |

**S102** identical, except S$46 instead of R$46
**T102** identical, except T$46 instead of R$46

**Figure P-49: Jump for Independent Component of Electricity Price**

**Random Variables**

| | Type | Cell | Distribution | Parameters | | |
|---|---|---|---|---|---|---|
| Jump 1 | wait | {{R99}} | **uniform** | min 0 | max 80 | |
| | size | {{S99}} | **uniform** | min 0 | max 2.5 | |
| | duration | **<------------------- not used ------------------->** | | | | |
| Jump 2 | wait | {{R100}} | **uniform** | min 16 | max 36 | |
| | size | {{S100}} | **uniform** | min 0 | max 2.5 | |
| | duration | **<------------------- not used ------------------->** | | | | |
| Principal Factors | offset | {{R94}} | **triangle** | min -1 | mode 0 | max 1 |
| | linear | {{R96}} | **triangle** | min -0.83 | mode -0.33 | max 1.17 |

source: L28_P.xls

**Figure P-50: Assumption Cells for Independent Component of Electricity Price**

## The Influence of Loads, Natural Gas Price, and Hydro Generation

The BMH study [16] provides the foundation for estimating the influence of loads, hydro generation, and natural gas price, on Mid-C electricity price. This study identified a regression equation for electricity price against these other influences. The equation, of course, is only accurate for the specific series of electricity prices and values of local variables assumed in the study. One difficulty with this approach, however, is that we assume electricity prices to some extent independent from these other factors. The sensitivity to each of the influences, however, is implicit in the regression equation. By taking the difference between regression equations corresponding to two Independent sets of Independent variables we obtain a difference between two electricity price series. If we interpret this has the difference in electricity price due to changes in assumptions about the independent variables, we obtain the result we need.

The BMH model is of the form

$$\ln(P_e(t)) = \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t)$$

where

$P_e(t)$ is electric price ($/MWh) over interval $t$

$P_g(t)$ is gas price ($/MMBTU) over interval $t$

$L(t)$ is peak load (MW) over interval $t$

$H(t)$ is hydrogeneration (MWa) over interval $t$

$\varepsilon(t)$ is an error term with a specified ARMA structure, having zero mean

$\alpha_i$ are constants determined by a statistical estimation technique, such the effect of weekday

| Coefficient | | Value |
|---|---|---|
| $\alpha_1$ | ln(Sumas price $/MMBTU) | 4.40E-01 |
| $\alpha_2$ | Max Load (MW) | 4.38E-05 |
| $\alpha_3$ | Hydro (MWa) | -1.34E-05 |

**Figure P-51: Electricity Price Sensitivity Coefficients**

Given three specific series $P^*_g(t)$, $L^*(t)$, and $H^*(t)$, this model predicts a specific $P^*_e(t)$. Given a distinct, arbitrary series $P_g(t)$, $L(t)$, and $H(t)$ and the associated, predicted $P_e(t)$, we have the following description of differences in electric price, given differences in the independent variables.

$$\begin{aligned} \ln(P_e(t)) - \ln(P^*_e(t)) &= \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t) - \alpha_0 + \alpha_1 \ln(P^*_g(t)) + \\ &\quad \alpha_2 L^*(t) + \alpha_3 H^*(t) + \varepsilon^*(t) \\ &= \alpha_1 \left[\ln(P_g(t)) - \ln(P^*_g(t))\right] + \alpha_2 \left[L(t) - L^*(t)\right] + \alpha_3 \left[H(t) - H^*(t)\right] + \varepsilon'(t) \end{aligned}$$

where

$\varepsilon'$ is a error term with the same properties as $\varepsilon$ and $\varepsilon^*$

We note several things. First, we have lost the constant coefficient, alpha zero. Second, the price of electricity does not appear on the right-hand side of this equation. The sensitivity of electric price to our independent variables does not depend on the absolute electric price.

Now, handed another series $Q_e(t)$ that shares the same sensitivity as $P_e(t)$ to our independent variables, we would predict $\ln(Q_e(t))$-$\ln(Q^*_e(t))$ would be described by the right-hand side of the preceding equation, where $Q^*_e(t)$ represents the value of $Q_e(t)$ when the perturbations of the independent variables are all zero.

The last step, then, is to take $Q^*_e(t)$, $P^*_g(t)$, $L^*(t)$, and $H^*(t)$ as the expected values of the electricity price, gas price, loads, and hydrogeneration values the regional model begins with, before accounting for the effect of the last three variables on the first. This gives us a means of forecasting electricity price $Q_e(t)$ given our assumed expected values for the four variables and excursions in the three independent variables. By taking the exponent of both sides,

$$\ln(P_e(t)) - \ln(P^*{}_e(t)) = \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t) - \alpha_0 + \alpha_1 \ln(P^*{}_g(t)) + \alpha_2 L^*(t) + \alpha_3 H^*(t)$$

implies

$$P_e(t) = P^*{}_e(t) \cdot \frac{1}{c} \cdot P_g(t)^{\alpha_1} \exp\{\alpha_3 H(t) + \alpha_2 L(t)\} \qquad (13)$$

where

$$c = P^*{}_g(t)^{\alpha_1} \exp\{\alpha_3 H^*(t) + \alpha_2 L^*(t)\}$$

Note in particular that equation (13) consists of the product of three terms, the unadjusted electricity price, a term of the form

$$P_g(t)^{\alpha_1} \exp\{\alpha_3 H(t) + \alpha_2 L(t)\}$$

and a term that corresponds to the reciprocal of this expression, albeit with different values for certain variables. The section returns to the use of this expression later, at the discussion of "Worksheet Function and Formulas," below.

<u>The Influence of Resource-Load Imbalances</u>

After taking into the account of local influences, such as natural gas price, the resulting electricity price may prove to be infeasible, in a sense. The portfolio model assumes that dispatchable resources respond to market prices for electricity.[27] When a power system is unconstrained by transmission or other import/export limitations, one typically does not

[27] Strictly speaking, the assumption is that dispatchable resources respond to some explicit, widely visible signal of generation value. In the world before price deregulation, the measure of merit was "system lambda," which indicated the variable cost of generation on the system. Regulators among others sometimes refer to this concept as the "avoided cost." Economists refer to this kind of value as a "shadow price." It simply represents a means for assigning value to alternative means to meeting system requirements or the requirements of others. In describing the portfolio model, all of the arguments work if one substitutes these identical concepts for that of deregulated market price for electricity.

have to worry about whether a given market price is somehow infeasible. Higher prices simply mean more generators will run.

If a lot of new generation capacity arrives in the region, the region produces more MWh of energy at the same wholesale electricity market price level. Now if loads are unchanged and exports are constraining, prices must fall to balance demand. Electricity prices are neither completely independent nor completely dependent of other variables. If the price is high, the resulting generation, after exports, may be surplus to requirements. Energy must be conserved, however: energy consumed must equal energy produced. In this example, the price must fall until the situation becomes feasible. The situation will be feasible when generation equals loads plus exports. Similarly, if the price is high, the resulting generation, after imports, may be inadequate for our requirements. The price must rise.

The Resource-Responsive Price (RRP) algorithm in the regional model finds a price that balances the system's energy. It does this by iteratively adjusting the price. Appendix L, in the section "RRP Algorithm," beginning on page L-51, describes this process in detail. Although this adjustment is made infrequently, keep in mind that it may be necessary and is part of the model logic. The RRP adjustment is also the principal means by which the model captures the influence of surplus and deficit resources and of forced outages.

### The Application to Decision Criteria

The regional model makes extensive use of spot electricity prices for estimating forward electricity prices and future spot prices. The philosophical basis for this choice is the observation that forward prices and estimates of future spot prices generally track existing spot prices, as discussed in the section "Gas Price" and illustrated in Figure P-39 above. For forward electricity prices, the argument received fortification in March 2003, when FERC staff released their final analysis of "Price Manipulation in Western Markets," which features a section on "The Influence of Electricity Spot Prices on Electricity Forward Prices"[22]. After examining prior analyses and studying the relationship between the prices, the report concludes "the forward power contracts negotiated during the period 2000-2001 in western United States were influenced by then-current spot prices, presumably because spot power prices influenced buyers' and sellers' expectations of spot prices in the future."

Because the horizon that a planner must consider depends in a sensitive fashion on the particular decision, technology, or power plant type she is considering, the role of electricity prices in each decision criterion differs. For this reason, Appendix L addresses their role in each specific criterion. (See section "Decision Criteria," beginning on page L-80 of Appendix L.)

In all cases, an average of current electricity prices over some brief history determines the influence on the decision criterion. When this section turns to "Worksheet Function and Formulas," it will identify the specific average and describe its formula.

The Application to Load Elasticity

Load elasticity played an important role in the history of the Council. Arguably, it was a failure to recognize load elasticity that was responsible for some of the region's planning failures in the 1970s and was therefore the impetus for creating the Power Planning Council.

Despite the prominence of the issue of load elasticity, the first versions of the regional model did not attempt to address it. The primary reason for this is that the effect of load elasticity is small relative to the load uncertainty that the model already incorporated. That is, because the regional model must already address futures where loads are much lower than could be accounting for price elasticity alone, it would seem unnecessary to include this smaller influence.

At the SAAC meetings where the Council Staff presented the representation of load behavior, however, several of the participants felt uncomfortable that there was no separate accounting for this effect. Ultimately, the Council Staff agreed that if for no other reason than to simplify the communication around treatment of load, it would be easier to include price elasticity explicitly.

Dr. Terry Morlan, who has prepared prior Council load forecasts, provided the basic characterization of price elasticity [**18**]. As we use the expression here, price elasticity of load is the change in load induced by a change in price over some specified time period.

$$\varepsilon_{l,p} = \frac{\Delta L}{L} \Big/ \frac{\Delta P}{P} = \frac{\Delta L}{L}\frac{P}{\Delta P}$$

where $L$ and $P$ are the load and price, respectively, at the beginning of the period. His sources indicate that the price elasticity over five years, which has a value of about -0.1, is less than that over 20 years, which he estimated at closer to -0.4. He said these factors would correspond to non-DSI retail rates, not wholesale price, which typically contribute about half to rate change. For a single year, and using wholesale prices, -0.02 max would probably be better figure for non-DSI loads. To understand the impact of this selection of values, examples may be helpful. A doubling in prices, say from \$30/MWh to \$60/MWh, well in line with changes the region has seen in the last couple of year, predict almost a 20 percent reduction in loads over 10 years, about 3600 MW. A one-year shock like the 2000-2001 energy crisis, where annual prices approached \$300/MWh would result in a similar change.

While at first glance, these seem comparable to changes the region has witnessed, in fact most of the change in loads corresponding to the 2000-2001 energy crisis is attributable to DSI load changes. (The regional model captures DSI loads separately. See the section on the principles of DSI modeling under the section "Multiple Periods" of Appendix L.) This level of elasticity therefore created unrealistic behavior – over-response of non-DSI load – in the regional model.

Another difficulty with modeling this level of elasticity in the regional model was that it seemed to create model instability. Feedback from load to price can create an undampened oscillation. High price can lower requirements load via elasticity, and low loads can depress electricity prices via the model's resource-responsive price (RRP) algorithm. One way to avoid this behavior is to use small elasticities, but without extensive study, it is not clear what the upper limit on the magnitude of the elasticities needs to be.

In the end, the model did incorporate load price elasticity, but the model caps their influence, and their magnitude is one-tenth of the original values. This section will return to formulas that implement the elasticity in the next discussion. The issue of how best to represent price elasticity, however, remains for now unresolved and potentially an area of research for the next plan.

## Worksheet Function and Formulas

With these preliminaries, tracing the formulas in the sample workbook should be straightforward. As is the custom, the discussion begins with column {{AQ}}, December 2009 through February 2010.

This section deals with the East and West, on- and off-peak quarterly average prices. Energy, cost, and dispatch calculations use these, as well as the decision criteria and elasticity calculations. This section does not address the decision criteria, however, because each decision criterion uses electricity prices differently. Therefore, Appendix L addresses each specific criterion separately. (See section "Decision Criteria," beginning on page L-80 of Appendix L.) This section also does not describe the worksheet formulas for load price elasticity, because Appendix L addresses those as well. (See the discussion "Loads" under the section "Multiple Periods," beginning on page L-59 of Appendix L.)

We begin with the calculation of flat[28] prices. A number of decision criteria, e.g., the decision criterion for price-responsive hydro, use flat electricity prices. The calculation of the electricity prices in {{AQ 224}} is

=AQ$207*4/7 + AQ$219*3/7

which is the average of on- and off-peak prices for electricity west of the Cascades, weighted by the number of hours on and off peak.[29]

Tracing backward, the on-peak price in {{AQ 207}} has the formula

=AQ$204*(1.01)

[28] "Flat" market prices are average prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

[29] There are 1152 hours on peak in a standard hydro quarter and 864 hours off peak. See Appendix L for more background about standard months and quarters. Then, for example, 4/7=1152/(1152+864).

This is the on-peak price for electricity East of the Cascades, with a one percent adder for losses and wheeling costs. The off peak price, AQ 219, has an identical formula that points to the off peak price for electricity East of the Cascades.

If we continue to trace the on-peak price, {{AQ 204}} has the formula

=AQ203+AQ200

This is the price adjustment in {{row 203}}, plus the unadjusted price in {{AQ200}}. The price adjustment in {{row 203}} does not contain any formulas. The RRP algorithm writes the values in this row. Appendix L, in the discussion of "RRP" from the section on "Multiple Periods" describes how this algorithm works to produce a price adjustment that balances energy requirements with energy sources.

The unadjusted on peak East of Cascades price in {{AQ 200}} uses the formula

=MIN(250, AQ$104*AQ$191*AQ$197)

This formula caps the East of Cascades prices at $250 a megawatt hour. The council chose this ceiling on electricity prices because it reflects the current limit imposed by the Department of Energy on west-wide prices in 2002.

The expression AQ$104*AQ$191*AQ$197 in the previous equation captures the influence of local hydro generation, loads, and natural gas prices on electricity prices. Referring to equation (13), the adjusted electricity price is the product of the unadjusted electricity price, times two factors of the form

$$P_g(t)^{\alpha_1} \exp\{\alpha_3 H(t) + \alpha_2 L(t)\} \qquad (14)$$

One of the factors is the reciprocal of this expression and includes parameters that describe "normal" values for hydro generation, loads, and natural gas prices. The other factor has these values for the particular future. In the workbook model, the value in {{AQ104}} is the unadjusted electricity price. The term {{AQ 191}} has the form in equation 14 with the values for hydro generation, loads, and natural gas prices from the current future. The term {{AQ 197}} has the reciprocal of the form in equation 14, with the values for expected hydro generation, base case loads, and base case natural gas prices. In the following, the section first traces the construction of the value in {{AQ 197}}. It then traces the value in {{AQ 191}}, and finally it proceeds with the construction of the unadjusted electricity price in {{AQ 104}}.

The formula in {{AQ 197}} is

=1/AQ$194^0.44/EXP(0.000045*AQ$195-0.000014*AQ$196)

which the reader will recognize as the constant 1/c in equation 13, page P-74. That is, {{AQ 194}} just points to the median forecast of natural gas prices in {{row 53}}. The cell {{AQ 195}} reconstructs the on peak west-of-Cascades load by multiplying the median load forecast by the on peak multiplier 1.14. (See discussion of this multiplier on page P-40, leading up to Figure P-25.) The value in cell {{AQ 196}} is the average on peak hydro generation for that period. The values in {{row 196}} are from reference [**19**].

The formula in cell {{AQ 191}} is

=AQ$178^0.44*EXP(0.000045*AQ$183-0.000014*AQ$188)

which is essentially identical except that it references the values for hydro generation, loads, and natural gas prices that manifested this particular modeling future.

## Hourly Behavior

The regional model assumes a lognormal standard deviation of hourly electricity prices that are 10 percent of the respective on- and off-peak quarterly averages. This means, for example, that if the average on-peak electricity price over the hydro quarter is $35/MWh,

- 99.7 percent of the hourly on-peak prices would fall below $47.25,
- 95.4 percent of the hourly on-peak prices would fall below $42.75,
- 68.3 percent of the hourly on-peak prices would fall below $38.68,
- 31.7 percent of the hourly on-peak prices would fall below $31.67,
- 4.6 percent of the hourly on-peak prices would fall below $28.66, and
- 0.3 percent of the hourly on-peak prices would fall below $25.93

The distribution of prices is not symmetric because of the nature of the lognormal distribution. That is, there is greater up-side variation than downside variation. It is also true that, while there is substantial variation in monthly and quarterly prices, daily prices correlate with monthly prices, and hourly prices correlated to daily prices. There is more information available, and therefore more price variation seen, on the longer time scales.

The last section of this chapter will address the correlations of hourly electricity price with those of other variables, such as natural gas price and loads.

## Comparison with the Council's Electricity Price Forecast

The Council electricity prices used in the final Plan and regional model L28 are from work that Council staff completed on October 21, 2004. (See Reference [**20**].) This section begins with a comparison of the Council's forecast with the independent term of the electricity price. Because this independent term represents the electricity price generated by the model before adjustments necessary to restore supply-demand balance, it is, in a sense, more directly comparable to the Council's price forecast. The final prices that resources see, however, can differ dramatically due to such adjustments. Therefore, the section also presents a statistical characterization across futures of the final, adjusted on- and off-peak prices for the Council's recommended resource plan.

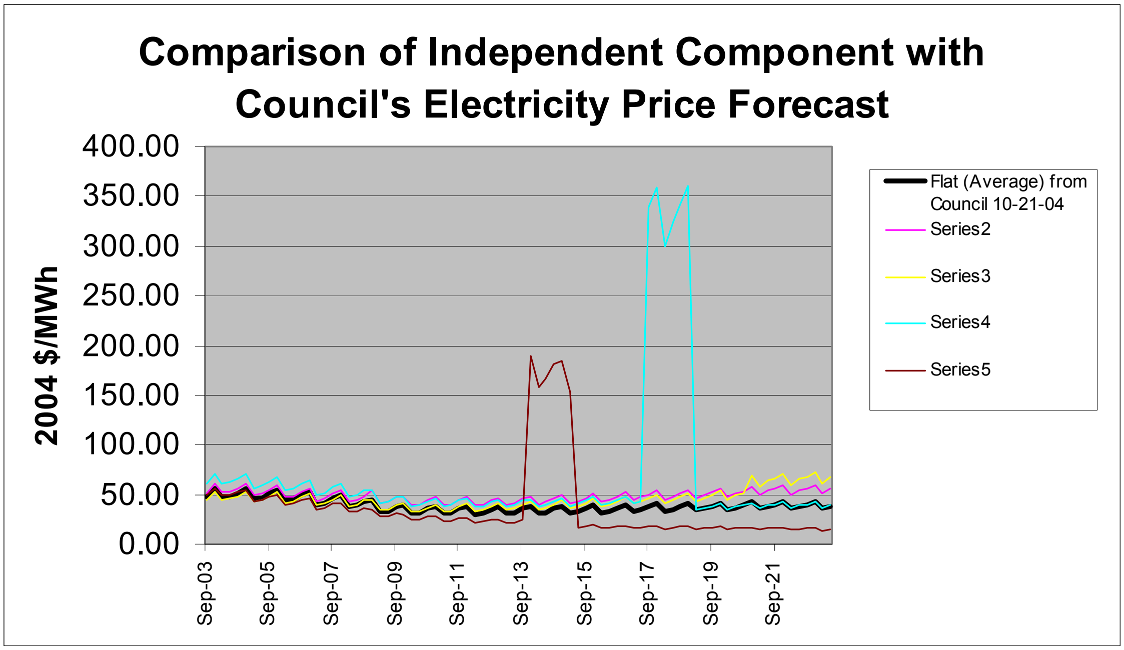



**Figure P-52: Comparison of Independent Term Futures with Council's Electricity Price Forecast**

The methods of principal factors, jumps, and specific variance described earlier produce the independent term of the electricity price. These use the Council's forecast as a median forecast. In Figure P-52, four random price futures appear along with the Council's forecast (the heavier line). This figure presents the average of the Council's forecast over each quarter, on- and off-peak.

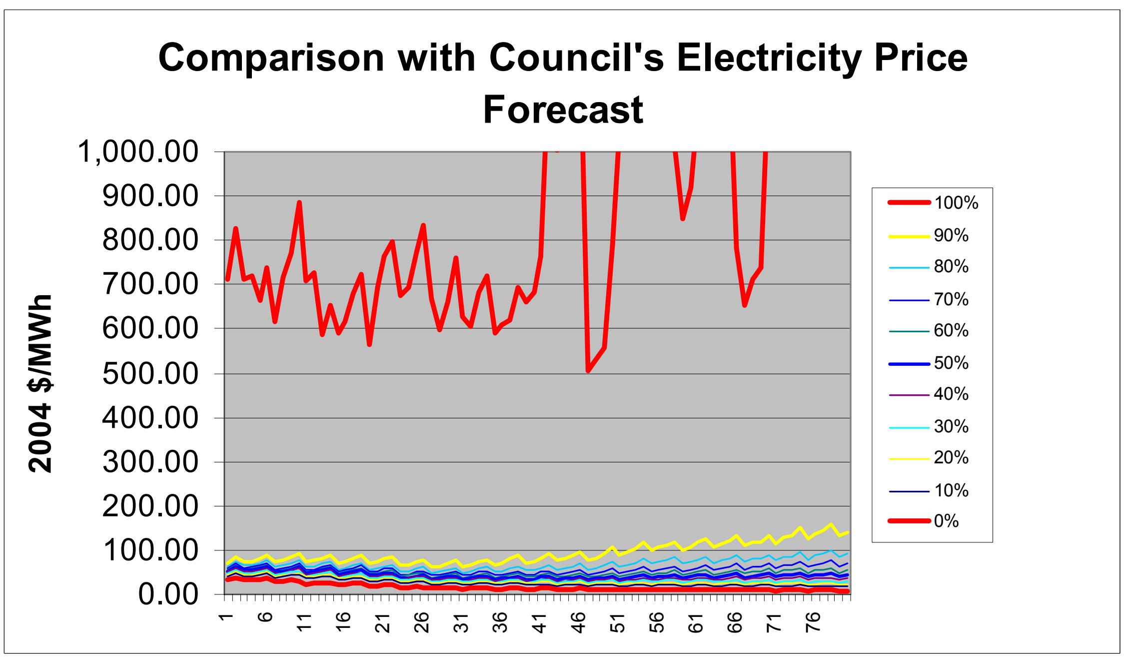



**Figure P-53: Statistical Characterization of Independent Term Futures**

There are price series both above and below the Council's forecast, but two of the forecasts have jumps that last a couple of years. To get a more representative idea of the likelihood of these excursions, a statistical representation is helpful. Figure P-53 shows the price deciles for the 750 futures. It is clear that prices above $150/MWh (2004$) are rare, occurring less than 10 percent of the time in each quarter, but their magnitudes can be quite significant. These low-probability events are largely due to the kinds of jumps illustrated in Figure P-52. Because the top decile dominates Figure P-53, the same information with that decile removed appears in Figure P-54.

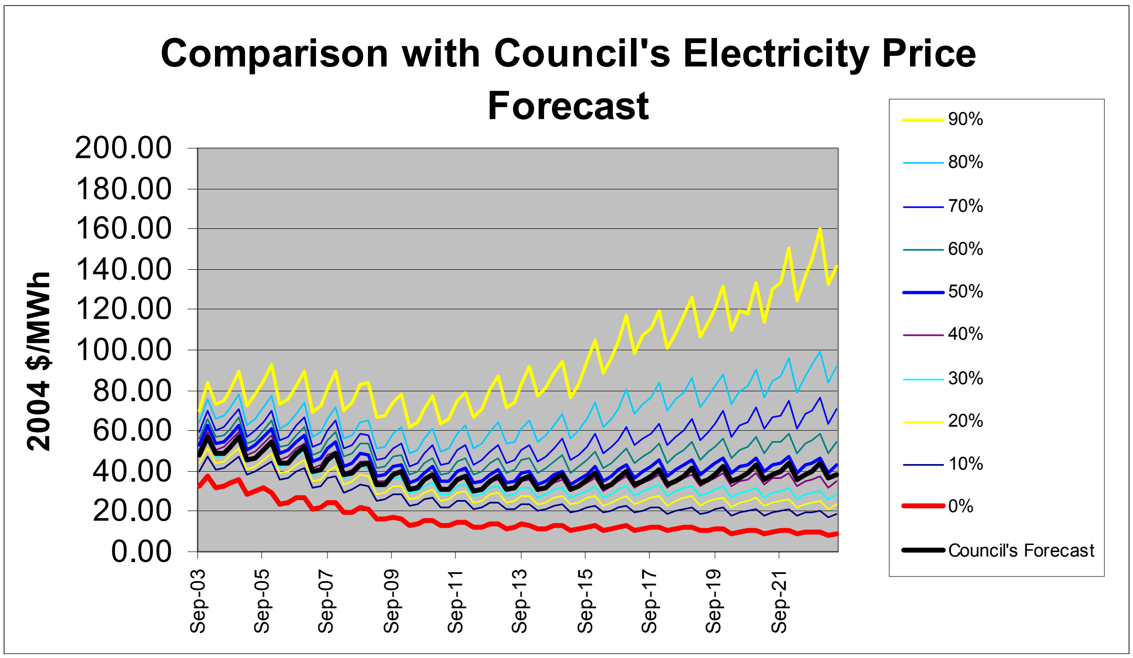



**Figure P-54: Statistical Characterization of Independent Term Futures (Lower 90 Percent)**

One observation about the distribution of the regional model's electricity prices at this point is that the regional model's price median (50 percent decile) is slightly above the Council's forecast. The difference is small, less than $6.29/MWh and averaging $4.26/MWh. The reason for this difference is the influence of jumps. In early studies with electricity price, jumps had a recovery period that would cause their influence over time to average out. The recovery time was so long, however, that it precluded multiple jumps in a study. (One jump's recovery needed to finish before another jump could take place.) For this reason, the model uses a somewhat shorter jump recovery period, which produces a net lifting of median prices. This slight lifting effect, however, is not considered material to the analysis. One reason the effect is immaterial is that other influences on the independent term, described next, dwarf the lifting.

As described earlier, the influences of loads, natural gas price, and resource generation, including hydro generation, are significant in the regional model's electricity price. The effect is evident in Figure P-55 for the four futures appearing in Figure P-52. In Figure P-55, the prices are depressed in general from those in Figure P-52. This should not be

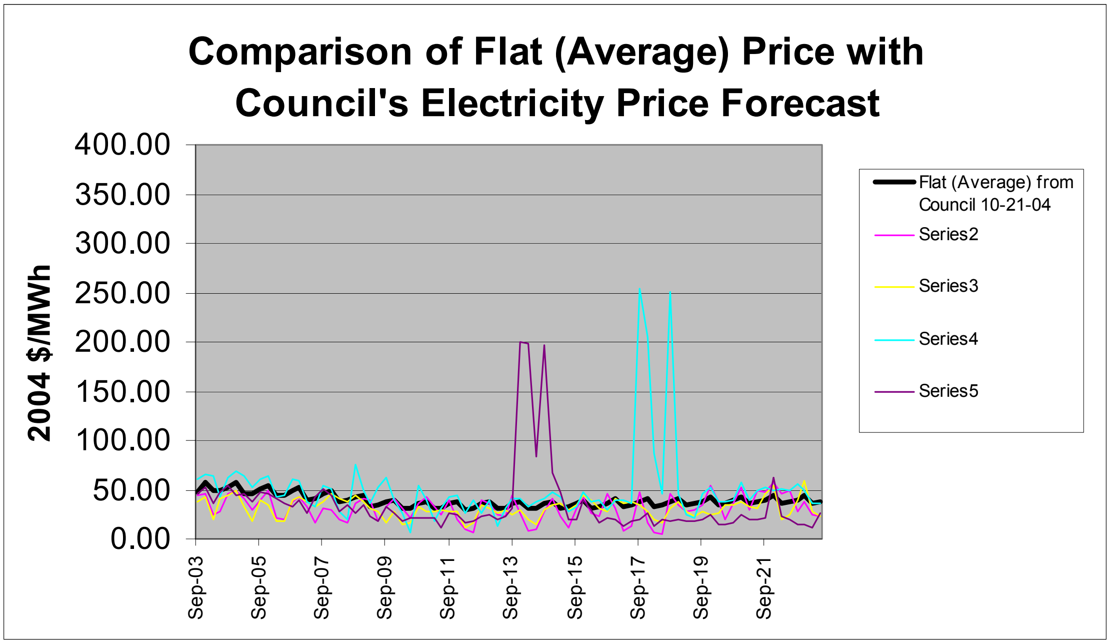



**Figure P-55: Comparison of Futures after Adjustment with Council's Electricity Price Forecast**

too surprising. The recommended resource plan, to which these price futures pertain, has significant resources in most futures. The downward pressure on electricity due to surplus resources alone will produce this effect.

A statistical comparison of the final on- and off-peak prices for the regional model to the Council's price forecast shows a similar pattern. While the median of independent term for electricity price is slightly above the Council's forecast, that for the regional model's

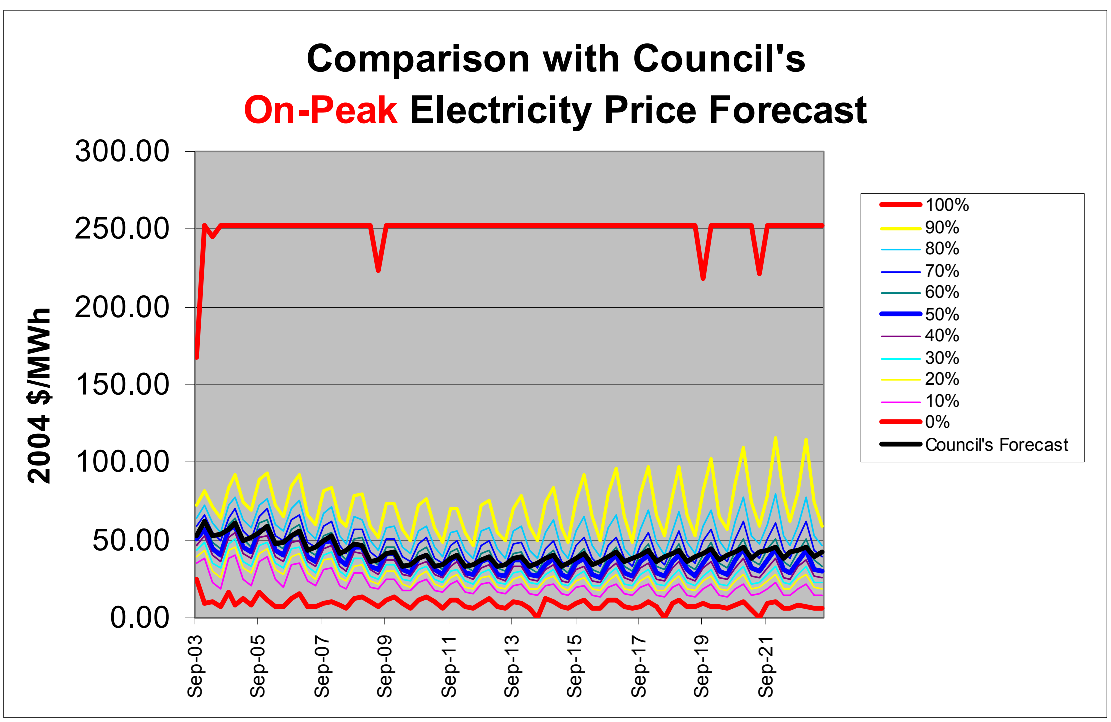



**Figure P-56: Statistical Characterization of Futures' On-Peak Prices**

on-peak price is slightly below that for the Council, as seen in Figure P-56. Another feature of the on-peak price distribution is that all prices are at or below $250/MWh. Actually, the ceiling price is slightly higher than $250/MWh, because the model assumes the cap applies to East-of-Cascades prices, and transmission costs cause the delivered price to West-of-Cascade loads to be higher. The reason for the ceiling is a cap imposed by the U.S. Department of Energy in June 2001.[30] The view of Staff and advisors is that this cap, or something like it, is likely to remain in place for the foreseeable future.

In Figure P-57, the off-peak price deciles from the regional model appear next to the Council's off-peak power price. As expected, the deciles general lie slightly below the corresponding on-peak price deciles.

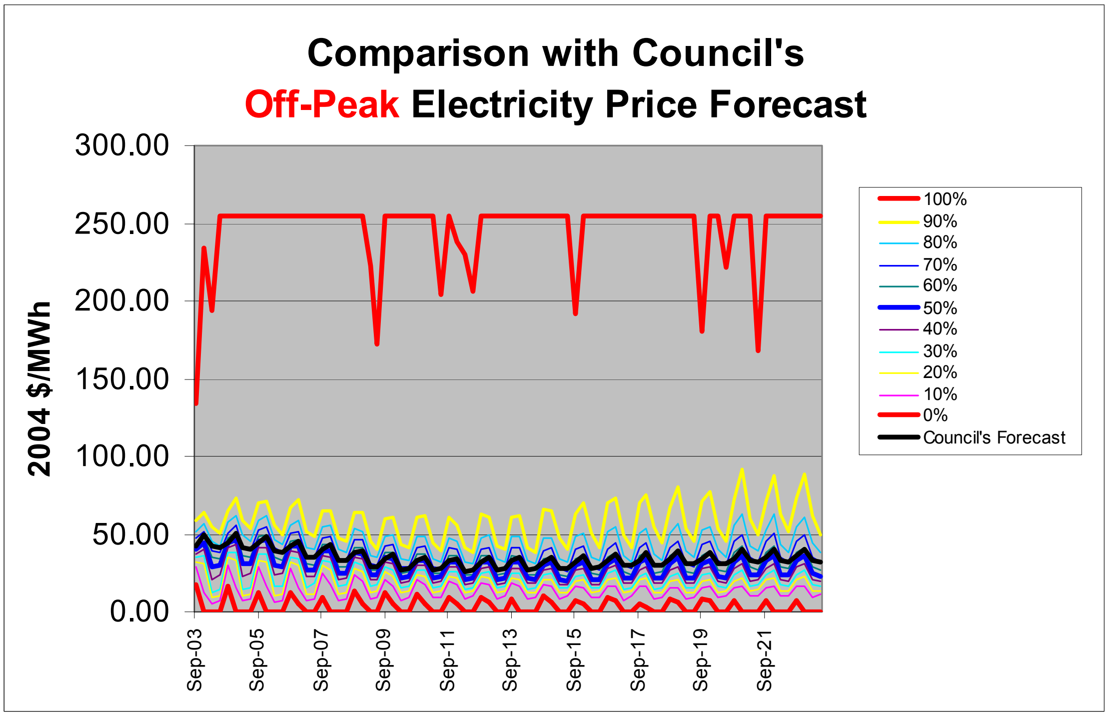



**Figure P-57: Statistical Characterization of Futures' Off-Peak Prices**

This concludes the discussion of electricity price and its associated uncertainty. A comparison of the regional model's prices with those of the Council's forecast shows some predictable differences. For the most part, however, there is general agreement, and the behaviors of the regional model's price futures appear reasonable.

[30] See, for example, Federal Energy Regulatory Commission, "Commission Extends California Price Mitigation Plan for Spot Markets to All Hours, All States In Entire Western Region," news release, June 18, 2001, EL00-95-031, EL00-98-030 and - 033, RT01-85-001 and -033, EL01-68-000 and –001.

## Forced outage rates

Unplanned outages affect the availability of power plants. Although, by definition, planners cannot forecast when these outages may occur for a specific plant, an ensemble of power plants have predictable behavior over sufficiently long time period. This behavior has permitted the power generation industry to acquire estimates of forced outage rates (***FOR***s) for various kinds of generation technology.

If *H* is the number of hours in a sufficiently large period, and *h* is the number of hours we expect a plant to be unavailable due to forced outages, the ***FOR*** is defined to be *h/H*. The period must only be large enough for the ***FOR*** to have predictive significance. Unfortunately, this tells us very little about the frequency or duration of forced outages. That is, even if a planner where using the same period as that on which the statistic is based, he cannot tell how long or how frequently a plant should be out of service. Of course, the period a planner would use would typically be smaller than that of the statistical sample, further muddying the water. Typically, the planner simply derates each period's energy by the ***FOR***. Unfortunately, this eliminates the risk of extended outages that would nevertheless be consistent with the statistical value.

The traditional approach to modeling forced outages statistically is to use a binomial distribution. The binomial distribution represents events that are independent of each other and of all other parameters when these events have fixed likelihood. For existing power plants, creating a stochastic variable with this distribution is relatively easy. For new power plants, however, the situation is more challenging in the regional portfolio model. As the number of identical power plants increases, the availability of the ensemble of power plants becomes more predictable. Because each new plant actually represents an ensemble of plants in the regional model, and because the number of plants, or cohorts, changes not only from plan to plan but from future to future, creating exactly the right distribution of energy duration is not easy.

Because of these considerations, the regional portfolio model uses a simpler approach than incorporating a binomial distribution. Energy deration due to forced outages is random variable with a symmetric triangular distribution, with an average (and most likely) value equal to the ***FOR*** (see Figure P-58). The generation technology determines the expected availability of each plant in the regional portfolio model. A Fall 2003 reassessment of regional power plant outage rates [**21**] form the basis for the technology values. A summary of the regional model's final values of FOR appear in Figure P-59.

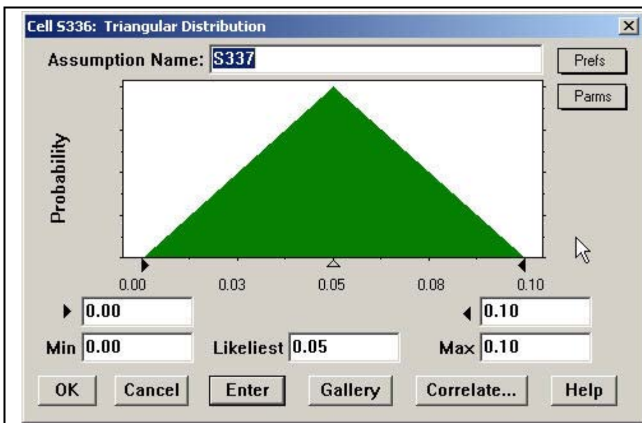


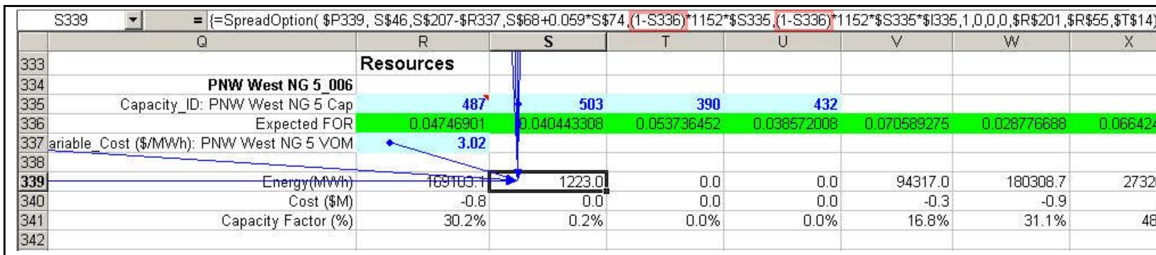

**Figure P-58: Typical FOR Distribution (FOR=0.05)**

In each future, the model makes a separate draw from the triangular distribution for each plant (or surrogate plant) for each hydro quarter. The energy of the plant over the period diminishes by a corresponding amount. For example, for the energy calculation for the plant "PNW West NG 5_006" in cell {{S339}}, one finds the references illustrated in Figure P-60. The reference to cell S336 in Figure P-60 is to this plant's FOR in this period. (The values in the assumption cell S336 happen to appear in Figure P-58.) As explained in Appendix L, the FOR must derate both the electric energy and the gas used.

| SourcePType | Fuel Type | FOR |
|---|---|---|
| Hyd | Water | 0.000 |
| Wind | Wind | 0.000 |
| CCCT | MT gas | 0.050 |
| CCCT | PNW E. gas | 0.050 |
| CCCT | PNW W. gas | 0.050 |
| Biomass ST | Mill Residue | 0.070 |
| Coal | MT coal | 0.070 |
| Coal | N. NV coal | 0.070 |
| Coal | PNW E. coal | 0.070 |
| Coal | PNW W. coal | 0.070 |
| GT | PNW E. gas | 0.070 |
| GT | PNW W. gas | 0.070 |
| GTAero | PNW E. gas | 0.070 |
| GTAero | PNW W. gas | 0.070 |
| STCG | No. 2 FO | 0.070 |
| STCG | PNW E. gas | 0.070 |
| STCG | PNW W. gas | 0.070 |
| IC | No. 2 FO | 0.080 |
| IC | PNW E. gas | 0.080 |
| IC | PNW W. gas | 0.080 |
| Nuclear | WNP-2 nuclear fuel | 0.090 |

**Figure P-59: FOR Rates**

For some plants, the model does not use this stochastic representation. For certain classes of resources, the model uses a simple capacity de-ration instead. These plants are those that are small, and would make trivial contribution to forced outages, and new units. For new units, the issue is the potential complexity, described above, associated with the changing number of units in the ensemble. Rather than introduce another source of complexity into the model that could influence the choice of new resources, by insisting on the use of a representation with known shortcomings, the model takes the simplest approach.


S339 = {=SpreadOption( $P339, S$46,S$207-$R337,S$68+0.059*S$74,(1-S336)*1152*$S335,(1-S336)*1152*$S335*$I335,1,0,0,0,$R$201,$R$55,$T$14)}

| | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|
| 333 | | Resources | | | | | | |
| 334 | PNW West NG 5_006 | | | | | | | |
| 335 | Capacity_ID: PNW West NG 5 Cap | 487 | 503 | 390 | 432 | | | |
| 336 | Expected FOR | 0.04746901 | 0.040443308 | 0.053736452 | 0.038572008 | 0.070589275 | 0.028776688 | 0.066424 |
| 337 | ariable_Cost ($/MWh): PNW West NG 5 VOM | 3.02 | | | | | | |
| 338 | | | | | | | | |
| 339 | Energy(MWh) | 169103.1 | 1223.0 | 0.0 | 0.0 | 94317.0 | 180308.7 | 27320 |
| 340 | Cost ($M) | -0.8 | 0.0 | 0.0 | 0.0 | -0.3 | -0.9 | - |
| 341 | Capacity Factor (%) | 30.2% | 0.2% | 0.0% | 0.0% | 16.8% | 31.1% | 48. |
| 342 | | | | | | | | |

**Figure P-60: Calculations in Cell {{S339}}**

Where the model uses the stochastic representation, the same availability is used both on- and off-peak. This makes sense, as an outage would not discriminate between these subperiods.

Finally, we point out that FOR is the only aspect of a future that is ***not*** computed in the range of the worksheet reserved for such calculations[31], although it could be and arguably should be. Keeping it with the resource facilitates review and verification of resource performance.

[31] The discussion "Logic Structure of the Portfolio Model" on pages P-15 ff identifies the specific range.

# Aluminum Price

Aluminum smelters in the Pacific Northwest have represented a substantial portion of regional loads in the past. This introduces a source of uncertainty directly related to the relative price of aluminum and the price of wholesale power. When electric power is costly relative to aluminum prices, smelters will shut down. The portfolio model captures the relationship among varying aluminum prices, electricity prices, and aluminum plant operation. In addition, the analysis considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period. Given the future electricity and aluminum price trends and variations and absent some policy intervention, the portfolio model results show an 80 percent likelihood of all aluminum plants closing during the forecast period.

To represent aluminum price futures, the Council evaluated several approaches, and the approach that most closely matched historical price patterns is a geometric Brownian motion (GBM) process with mean reversion.  Aluminum prices do not exhibit the seasonal shape that natural gas and electricity prices possess. Instead, they tend to wander away from a trend with quasi-cyclical excursions of varying regularity, as illustrated in Figure P-61.  (See Reference [**22**].)

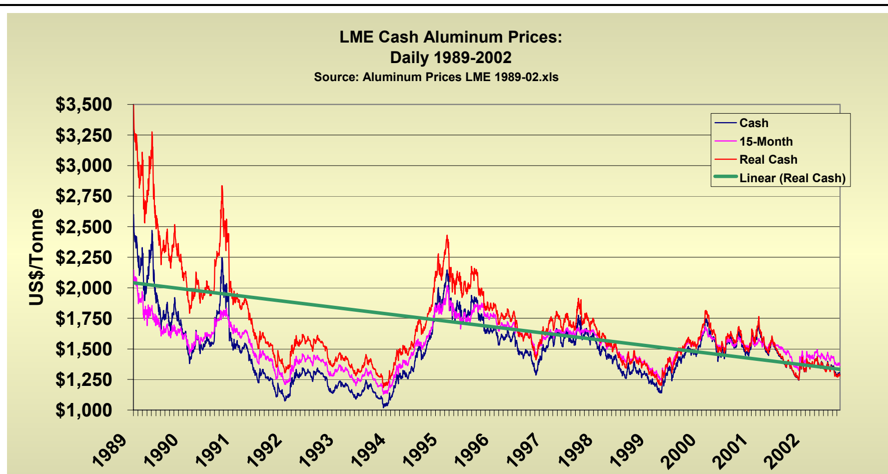



**Figure P-61:  Historical Aluminum Prices (2002 $/metric Tonne)**

In Figure P-61, a linear regression line emphasizes the downward trend in aluminum prices that has been evident over the last 20 years or so.

The section "GBM with Mean Reversion," beginning on page P-25 describes the mathematical principles of the stochastic process.  The regional model workbook implements the equations as follows:

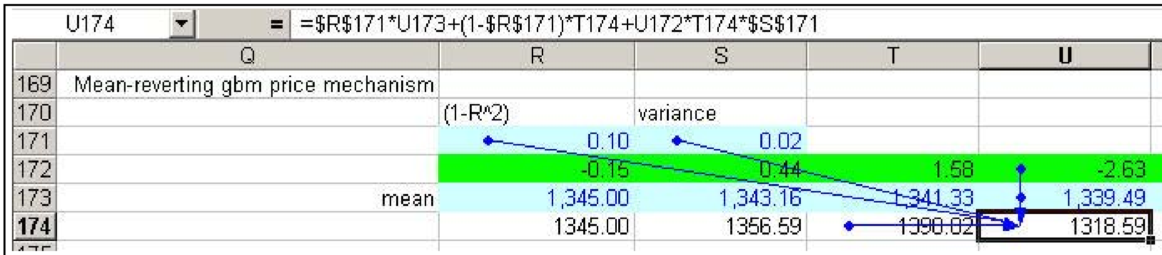



**Figure P-62: Workbook Formula for GBM with MR**

The formula

=$R$171*U173+(1-$R$171)*T174+U172*T174*$S$171

replicates the equation from the section "GBM with Mean Reversion,"

$$p_t + dp_t = p_t + a(b - p_t)dt + \sigma p_t dz = abdt + (1 - a)p_t dt + dz \cdot p_t \sigma$$

where

$p_t$ is stochastic variable in question

$dp_t$ is the change in $p_t$ from the previous step

$dz$ is a drawn from a N(0,1) process

$dt$ is the step size, which has value 1 for discrete processes

$a$ is constant which controls the rate of reversion

$b$ is the equilibrium level

$\sigma$ is the standard deviation of $p_t$

(Note that the label "variance" in cell {{S 172}} of Figure P-62 is incorrect. This value is the standard deviation of the log-transformed aluminum prices. See Reference [**23**].) A Crystal Ball assumption cell provides an underlying Weiner process *dz* with the appropriate distribution (Figure P-63).

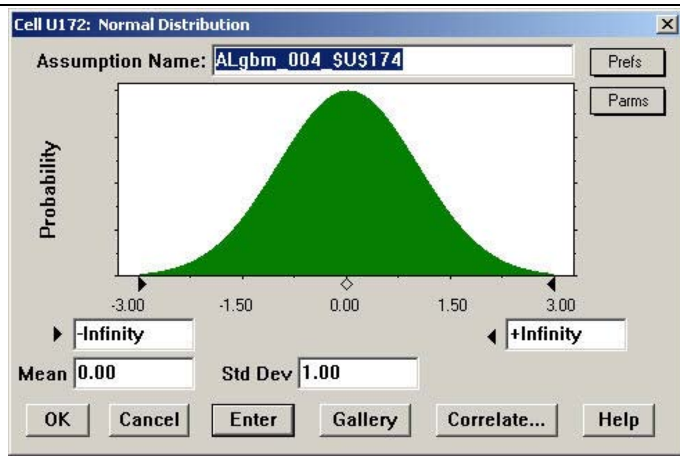



**Figure P-63: Assumption Cell {{U 172}}**

Figure P-64 illustrates the behavior of this process representation. The individual futures exhibit the same kind of irregular walk around the mean that does the historical data. The values are smoother, however, as expected from quarterly averages.

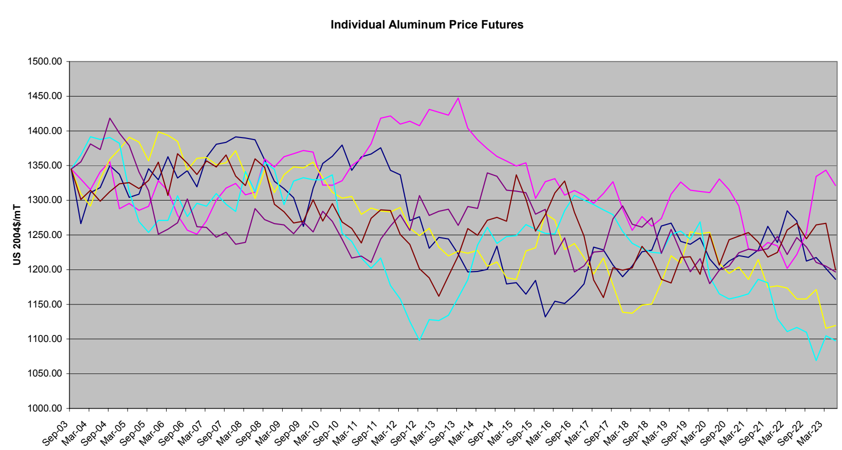



**Figure P-64: Selected Aluminum Price Futures**

Figure P-65 provides additional, statistical description of the aluminum price futures. It shows the quarterly deciles, plotted against the periods in the study. It is evident that the mean to which prices are reverting is trending down, consistent with the historical price behavior. The mean price descends from the May 2004 price of $1345/mT to $1200/mT (2004 $) by the end of the study (see Reference [**24**]).

# CO2 tax

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

Because it is unlikely that reduction in carbon dioxide production will occur without cost, future climate-control policy is a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to be the most cost-effective approach to CO2 control. The model, however, uses a fuel carbon content tax as a proxy for the cost of carbon dioxide control, whatever the means of implementation. The effect on existing power plant generation and the economic value of new generation would be

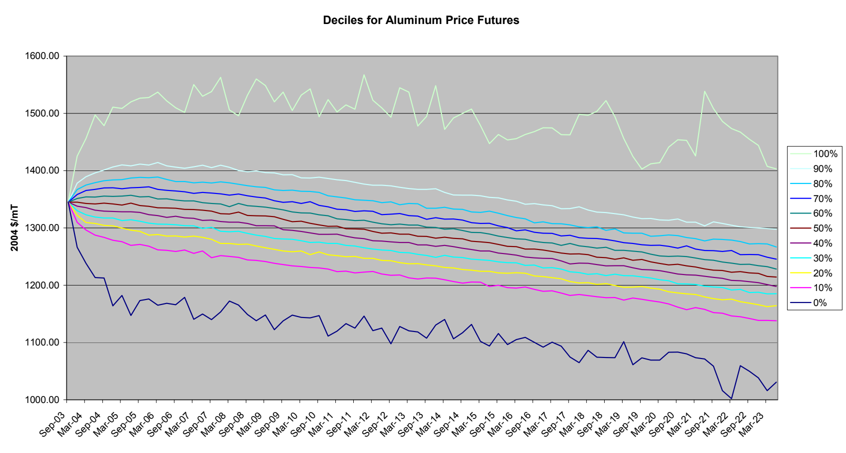



**Figure P-65: Deciles for Quarterly Aluminum Prices**

representative of any type of effort to control CO2 production using carbon-proportional constraints.

In the model, a carbon tax can arise in any election year.[32] (See Reference [**25**]) The probability of any such tax during the forecast period is sixty-seven percent. If enacted, the value for the carbon tax has a uniform distribution between zero and $15 per ton if it is enacted between 2008 and 2016; and between zero and $30 per ton if enacted thereafter (2004$). These draws are independent of other parameters, although other stochastic variables, like production tax credit, depend on CO2 tax. The two sections following this one describe the relationship.

[32] At a May 20, 2003 meeting held in the Council's main Portland office, experts on carbon tax were reluctant to speculate on the likelihood or magnitude on any carbon tax. There did appear to be agreement, however, that if the United States enacted a carbon tax, it would require the support of the Executive Branch of the U.S. Government. The change would likely arrive, therefore, with a change in administration.

The probability distribution of this stochastic variable was the subject of intensive debate during the development of the Plan. While authoritative studies[33] supported carbon tax as high as \$100/ton$_{CO2}$, the final values had as much to do with the principle of "thresholding" as with perspectives of what likely values might be. Specifically, increasing the $CO_2$ tax had little effect on the plans lying on the efficient frontier. Using higher values would therefore have only token value and would render the model results questionable among those who do not believe higher taxes are likely. Few participants, on the other hand, could argue for smaller probability and magnitude of tax. One third of the futures had no tax at all. The expected value tax rate in the regional model until 2020 is less than the expected value forecast that appeared in PacifiCorp's 2004 IRP [**26**].[34] PacifiCorp is heavily reliant on coal-fired power, the cost of which would be especially sensitive to carbon tax, and high future $CO_2$ tax-rate assumptions probably do not elevate PacifiCorp stockholder wealth. That is, PacifiCorp has little motivation to argue for high likely $CO_2$ tax rate.

Given what some might consider such a low expected $CO_2$ tax rate assumption, did the tax matter? It did, but for reasons that may require explanation. First, in a risk model, the extreme values are as important as the expected value, and the high end of the range exceeded what some would consider likely, as it should. Second, what drives much of the resource selection in the regional model is not a single source of risk, such as $CO_2$, but combinations of risks. Each independent source of risk adds to the expected net cost of the resource. For coal-fired power plants, for example, lack of planning flexibility, capital cost exposure, and load uncertainty were equally issues affecting economic feasibility.

Figure P-66 has six of the first $CO_2$ tax futures, although in two of those futures no tax arrives. In each future, there is at most only one arrival of taxes, and it occurs as a step. This is, in fact, the way the regional model represents $CO_2$ tax in all futures. However, the *maximum* size of the step depends on the year it happens, as mentioned earlier.

[33] See, for example, ***MIT Joint Program on the Science and Policy of Global Change***, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States, The McCain-Lieberman Proposal*, Report 97, June 2003, available at http://mit.edu/globalchange/www/reports.html#r100

[34] PacifiCorp used \$8.00/ton$_{CO2}$ (2008 \$) beginning in 2010 or about \$7.38 in 2004 dollars using PacifiCorp's inflation assumption of 2.02 percent. Their study discounted this value in the first two years only to \$3.69 (2004 \$) in 2010 and to \$5.54 (2004 \$) in 2011. (See Table C.7, and supporting discussion in Appendix C, page 37 of the PacifiCorp 2004 IRP, Technical Appendix.) The regional model's expected tax rate grows and surpasses PacifiCorp's by less than \$0.46 only in the last three years of the study.

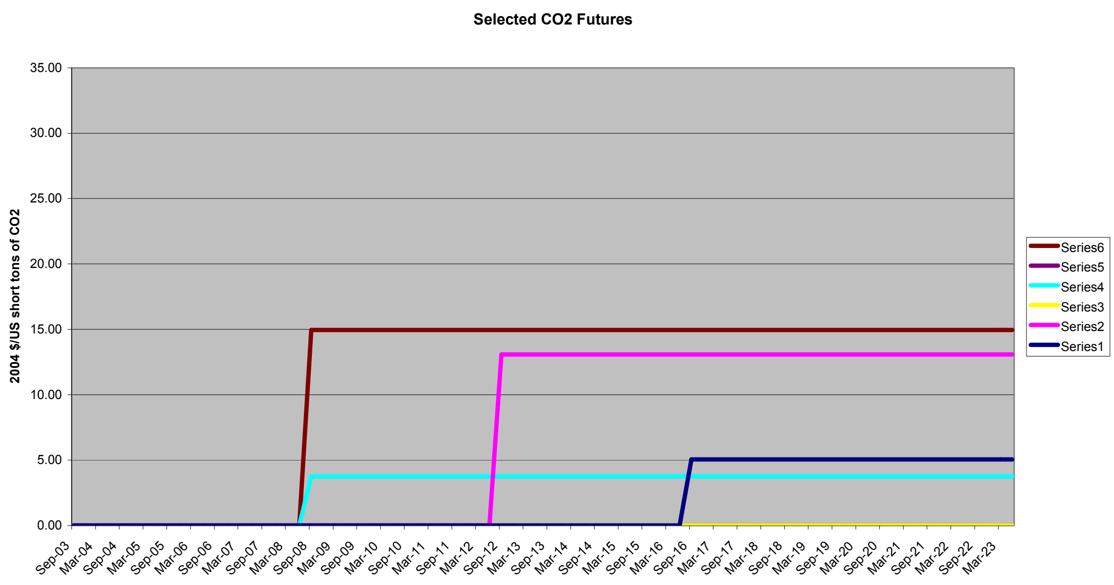



**Figure P-66: Selected CO2 Futures**

Figure P-67 provides some descriptive statistics across periods. In addition to the deciles the reader has seen in prior illustrations, the graph includes the average $CO_2$ tax across all futures. (A dotted line identifies the average.) One of the striking features of this graph is the non-appearance of the deciles below 40 percent. Those deciles all lie on the zero-tax line. On reflection, however, this is consistent with the earlier observation that approximately a third of the futures contain no tax.

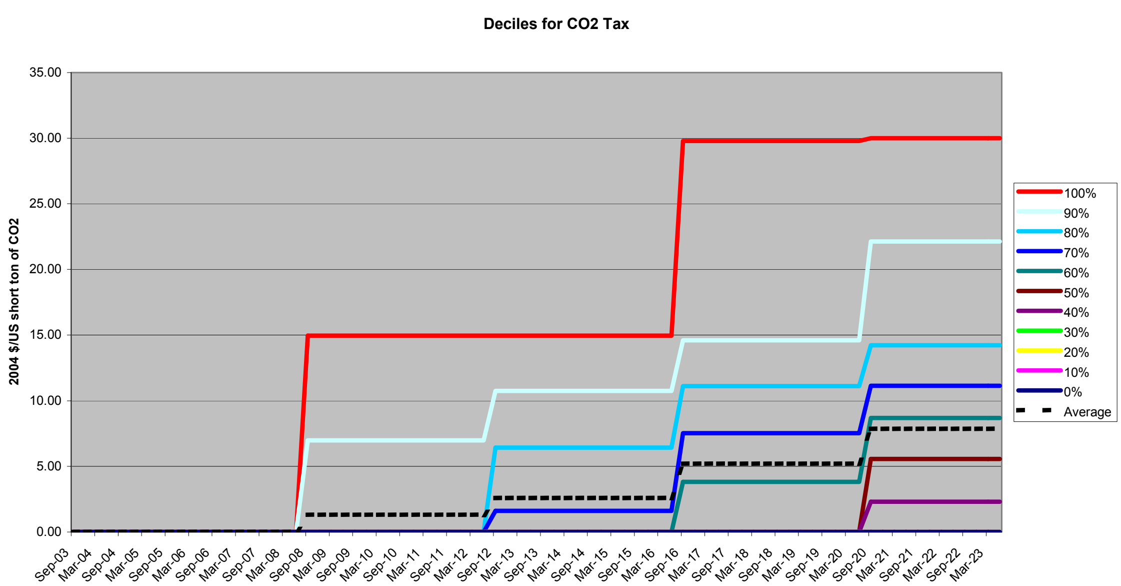



**Figure P-67: CO2 Statistics**

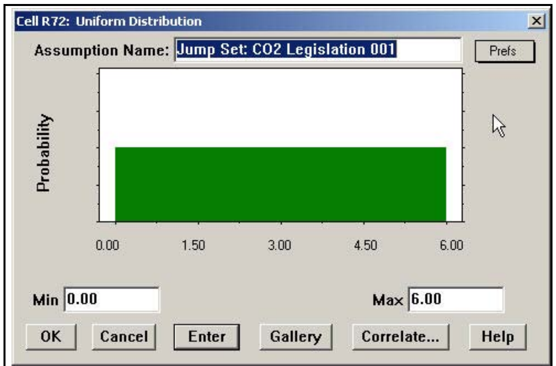



**Figure P-68: Timing**

To capture this behavior in the workbook, only two Crystal Ball assumption cells are necessary. The first one, {{R72}}, illustrated in Figure P-68, controls the timing of step. It is a uniform distribution from 0.0 to 6.0. The explanation for the range of this random variable becomes evident in a moment. The second assumption cell, {{S72}}, illustrated in Figure P-69, determines the size of the step.

The model first determines in which column any step takes place, as shown in Figure P-70. The formula in cell {{T72}}, for example, is

=IF(T$46>4+INT($R72)*16, $S72,0)

This formula compares the period ({{T46}}) to one of the values 4, 20, 36, 52, 68, or 84, which {{R72}} determines and which each occurs equal likelihood. (The value 100, corresponding to {{R72}} having value 6.0, has probability zero.) These period values correspond to the period September through December of each election year. If the column's period number exceeds this value, it assumes the value in cell {{S72}}, which will determine the size of the step.

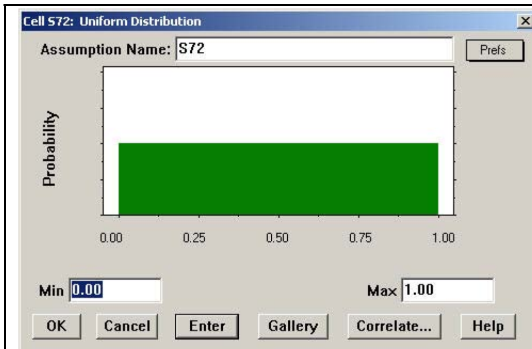



**Figure P-69: Size**

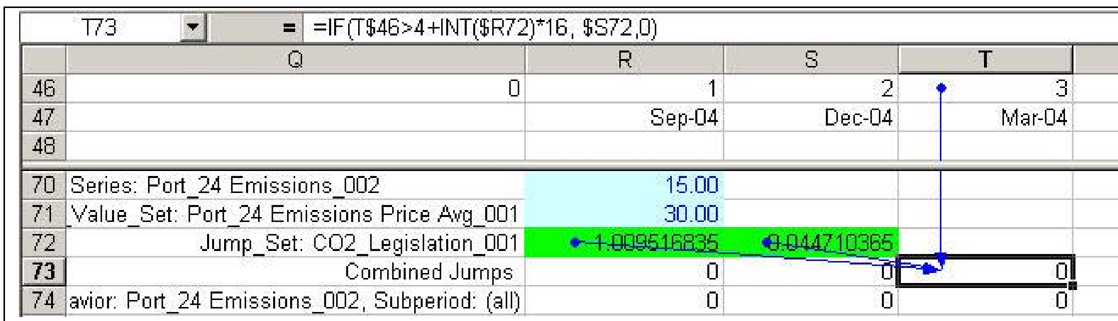



**Figure P-70: Normalized Step**

At this point in the calculation, the values in {{row 73}} have the value in cell {{S72}} if they belong to periods after the first occurrence of any step. Otherwise, they have the value 0.0.

The task remaining for formulas in {{row 74}} is to properly scale these values to the real tax rate. The formulas are of the form

=IF($R$72<1,0,IF($R$72<3,T73*$R$70,T73*$R$71))

and Figure P-71 illustrates the references. The first "if" test prohibits any tax from appearing during the George W. Bush administration. This was a modification made later in the development of the model. It effectively decreases the probability of a tax in the study period. The second "if" test scales the range of the tax to $15/ton before 2016 and to $30/ton subsequently.

T74 = =IF($R$72<1,0,IF($R$72<3,T73*$R$70,T73*$R$71))

| | Q | R | S | T |
|---|---|---|---|---|
| 46 | 0 | 1 | 2 | 3 |
| 47 | | Sep-04 | Dec-04 | Mar-04 |
| 48 | | | | |
| 70 | Series: Port_24 Emissions_002 | 15.00 | | |
| 71 | Value_Set: Port_24 Emissions Price Avg_001 | 30.00 | | |
| 72 | Jump_Set: CO2_Legislation_001 | 1.009516835 | 0.044710365 | |
| 73 | Combined Jumps | 0 | 0 | 0 |
| 74 | avior: Port_24 Emissions_002, Subperiod: (all) | 0 | 0 | 0 |

**Figure P-71: Nominalized Step**

## Production Tax Credits

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

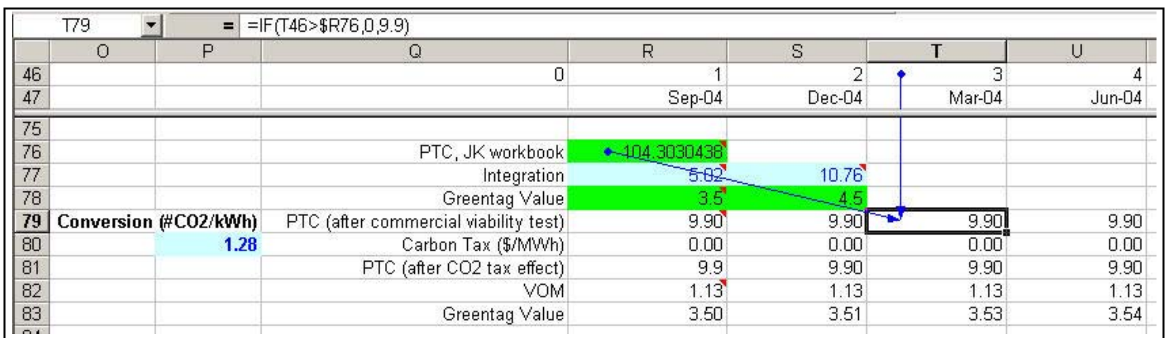
The first event is termination due to cost-competitiveness. There is a small probability the PTC could disappear immediately, if congress decided renewable energy technology is sufficiently competitive and funds are needed elsewhere. The likelihood of termination peaks in the model when the fully allocated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

The second event that modifies the PTC in the Council's model is the advent of a carbon penalty. This event is related to the first, in that a carbon penalty would make renewables that do not emit carbon more competitive relative to those generation technologies that do. A CO2 tax of less than about $15 per short ton of CO2, however, would not completely offset the support of the PTC. For this reason, the value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains[35]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range.

A three-step process determines the PTC value the regional model will use in a given future and period. In the first step, a formula like

=IF(T46>$R76,0,9.9)

in cell {{T79}} determines whether the wind plant should be commercially viable. Figure P-72 illustrates the references. The label in {{Q79}}, "PTC (after commercial



T79 = =IF(T46>$R76,0,9.9)

| | O | P | Q | R | S | T | U |
|---|---|---|---|---|---|---|---|
| 46 | | | 0 | 1 | 2 | 3 | 4 |
| 47 | | | | Sep-04 | Dec-04 | Mar-04 | Jun-04 |
| 75 | | | | | | | |
| 76 | | | PTC, JK workbook | 104.3030438 | | | |
| 77 | | | Integration | 5.82 | 10.76 | | |
| 78 | | | Greentag Value | 3.5 | 4.5 | | |
| 79 | Conversion (#CO2/kWh) | | PTC (after commercial viability test) | 9.90 | 9.90 | 9.90 | 9.90 |
| 80 | | 1.28 | Carbon Tax ($/MWh) | 0.00 | 0.00 | 0.00 | 0.00 |
| 81 | | | PTC (after CO2 tax effect) | 9.9 | 9.90 | 9.90 | 9.90 |
| 82 | | | VOM | 1.13 | 1.13 | 1.13 | 1.13 |
| 83 | | | Greentag Value | 3.50 | 3.51 | 3.53 | 3.54 |

**Figure P-72: PTC Calculation, Step 1**

viability test)," is misleading. Federal politics would determine viability, and commercial competitiveness is one of several issues. As mentioned above, the PTC could go away almost immediately, if it became unpopular for any reason. The PTC may also outlive its original purpose if political or economic forces support retention. The distribution of a random variable describing this lifetime must therefore have some small, positive value in the near term and in years after renewables would become competitive.

[35] 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.

This model compares Council forecasts of wind generation fixed costs to its electric market prices to estimate when renewables would become competitive. In an outboard calculation (Reference [**27**]), Staff estimated wind would achieve economic competitiveness in 2016. This assumes an electric price of $40/MWh in that year and wind generation costs that decline at about 1.7 percent per year (Reference [**28**]). Moreover, Staff assumed the chance of the PTC surviving when wind generation cost fell to $30/MWh in 2034 would be nil, so the model uses a triangular distribution for the lifetime of the PTC. The year 2016 corresponds to the 52nd period, so the distribution has

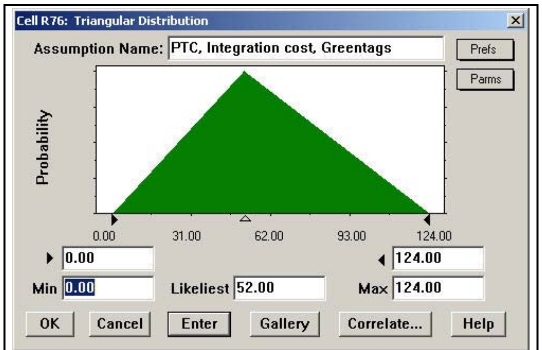



**Figure P-73: Political Viability Distribution**

52 as its mode; the year 2035 corresponds to the 124th period, so that value determines the maximum value. Because the study only extends 80 periods, there is a substantial probability that the PTC does not disappear due to political non-viability during the study.

The formula in cell {{T79}} stipulates that if the period exceeds the value of the random variable, the PTC is zero; otherwise it has a real levelized value $9.90/MWh in 2004 dollars (Reference [**29**]). This value corresponds to the current credit of roughly 1.7 cents/kWh in year 2000 dollars, using Council assumptions for wind capacity factor and inflation. Staff elected not to make the PTC value a random variable and saw no compelling reason to assume this would either increase or decline over time.

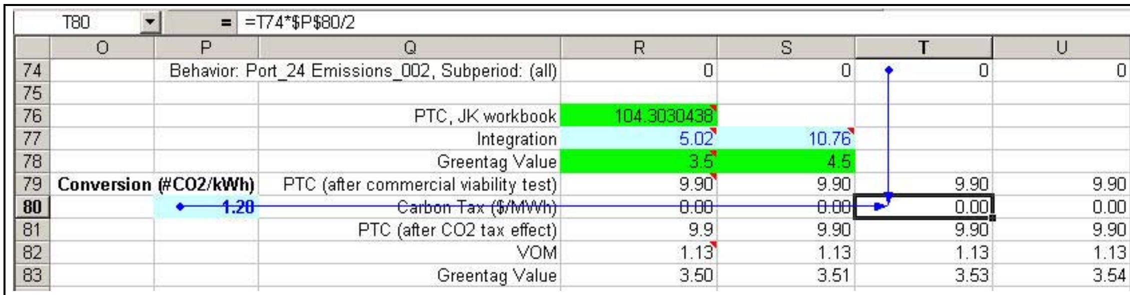
The second step of the process to determine the PTC value the regional model is an examination of any $CO_2$ tax in the period. The cell {{T80}} is typical and contains

=T74*$P$80/2

(Cell references appear in Figure P-74.) This formula converts the tax in $/US short ton (2004 $) to $/MWh using the value in {{P80}}[35]. The conversion factor is in pounds of $CO_2$ per kWh, so the conversion is

$/MWh = $/ton • tons/pound • pounds/kWh • kWh/MWh or
$/MWh = $/ton • pounds/kWh • 1000/2000

This gives rise to the factor of two in the denominator of the formula in cell {{T80}}.



T80 = =T74*$P$80/2

| | O | P | Q | R | S | T | U |
|---|---|---|---|---|---|---|---|
| 74 | | Behavior: Port_24 Emissions_002, Subperiod: (all) | | 0 | 0 | 0 | 0 |
| 75 | | | | | | | |
| 76 | | | PTC, JK workbook | 104.3030438 | | | |
| 77 | | | Integration | 5.02 | 10.76 | | |
| 78 | | | Greentag Value | 3.5 | 4.5 | | |
| 79 | Conversion (#CO2/kWh) | | PTC (after commercial viability test) | 9.90 | 9.90 | 9.90 | 9.90 |
| 80 | | 1.20 | Carbon Tax ($/MWh) | 0.00 | 0.00 | 0.00 | 0.00 |
| 81 | | | PTC (after CO2 tax effect) | 9.9 | 9.90 | 9.90 | 9.90 |
| 82 | | | VOM | 1.13 | 1.13 | 1.13 | 1.13 |
| 83 | | | Greentag Value | 3.50 | 3.51 | 3.53 | 3.54 |

**Figure P-74: Carbon Tax Effect (Step 2)**

The third and final step of the process to determine the PTC value the regional model implements the "PTC offset" due to any $CO_2$ tax. In the draft Plan, the PTC went away in any future where any positive CO2 tax occurred. The issue that arose between the draft and final plan was, "Would the PTC go away entirely even if the $CO_2$ tax were very small?" The problem was that the combined support for renewables could undergo a discontinuity, a net drop, if the $CO_2$ tax were very small. This struck the Council as unrealistic.

To address this matter, new logic provided for the remaining PTC to be a function of the magnitude of the $CO_2$ tax. Figure P-75 illustrates the PTC remaining. In terms of support for wind generation, the PTC corresponds to a $15.47/ton $CO_2$ tax, given Council assumptions. With the new logic, if the $CO_2$ tax that arises is less than half of this, the PTC remains in place; if the tax is fifty percent higher than this, it disappears entirely. Between those values, it declines dollar for dollar with the tax rate. Figure P-76 shows the combined advantage relative to gas-fired generation provided by the $CO_2$ tax and the PTC. Note that no discontinuity exists for the combined support.

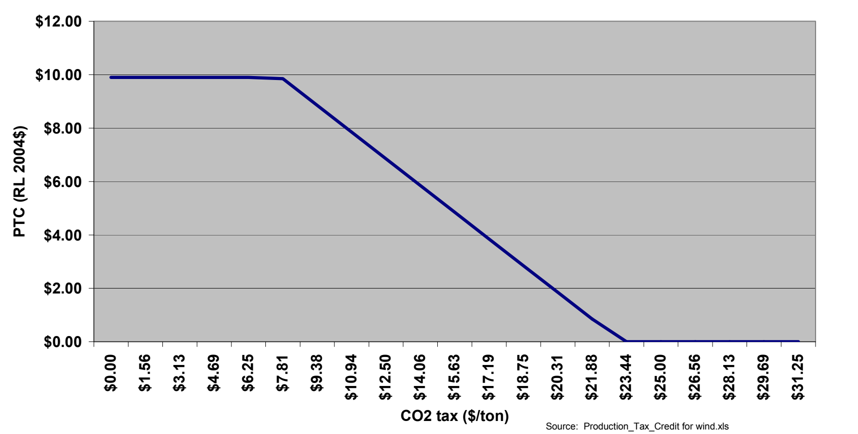



**Figure P-75: PTC as a Function of CO2 Tax**

Figure P-77 shows how the workbook implements the PTC with formulas, such as that in cell {{T81}}. Again, if the tax has become politically non-viable, the PTC from cell {{T79}} in this example is zero.

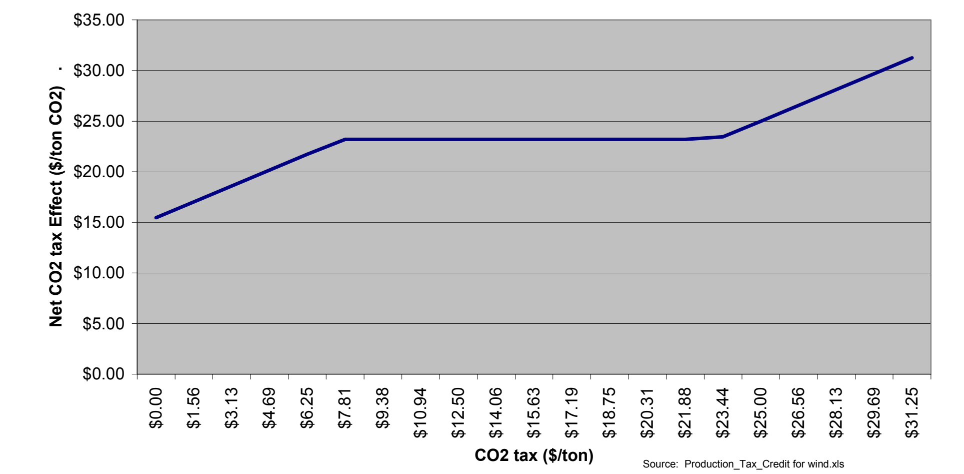
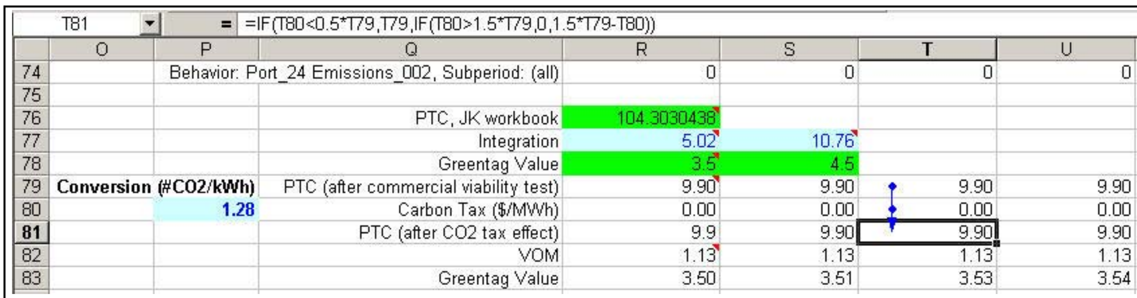



**Figure P-76: Combined PTC and CO2 Tax Effects**



T81 = =IF(T80<0.5*T79,T79,IF(T80>1.5*T79,0,1.5*T79-T80))

| | O | P | Q | R | S | T | U |
|---|---|---|---|---|---|---|---|
| 74 | | Behavior: Port_24 Emissions_002, Subperiod: (all) | | 0 | 0 | 0 | 0 |
| 75 | | | | | | | |
| 76 | | | PTC, JK workbook | 104.3030438 | | | |
| 77 | | | Integration | 5.02 | 10.76 | | |
| 78 | | | Greentag Value | 3.5 | 4.5 | | |
| 79 | Conversion (#CO2/kWh) | | PTC (after commercial viability test) | 9.90 | 9.90 | 9.90 | 9.90 |
| 80 | | 1.28 | Carbon Tax ($/MWh) | 0.00 | 0.00 | 0.00 | 0.00 |
| 81 | | | PTC (after CO2 tax effect) | 9.9 | 9.90 | 9.90 | 9.90 |
| 82 | | | VOM | 1.13 | 1.13 | 1.13 | 1.13 |
| 83 | | | Greentag Value | 3.50 | 3.51 | 3.53 | 3.54 |

**Figure P-77: Transition Logic (Step 3)**

Figure P-78 characterizes the deciles for the PTC before adjustment for $CO_2$ tax. As

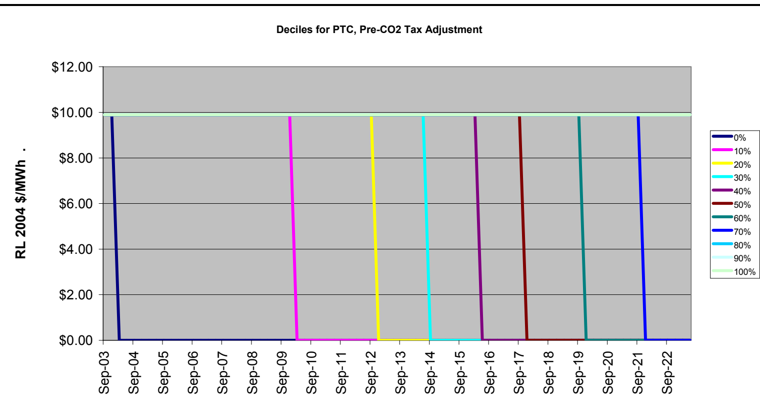



**Figure P-78: Deciles for PTC before the CO2 Tax adjustment**

expected, the median value is around 2016, although the median is not the mode for the distribution in Figure P-73.

Figure P-79 has deciles for the final PTC, after the CO2 tax adjustment. The effect of the tax is evident in each of the decile curves, with greater effect visible in out-lying years. The average of the final, quarterly values is a dotted line in this Figure. It also behaves as expected. Appendix L documents the final use for PTC value.

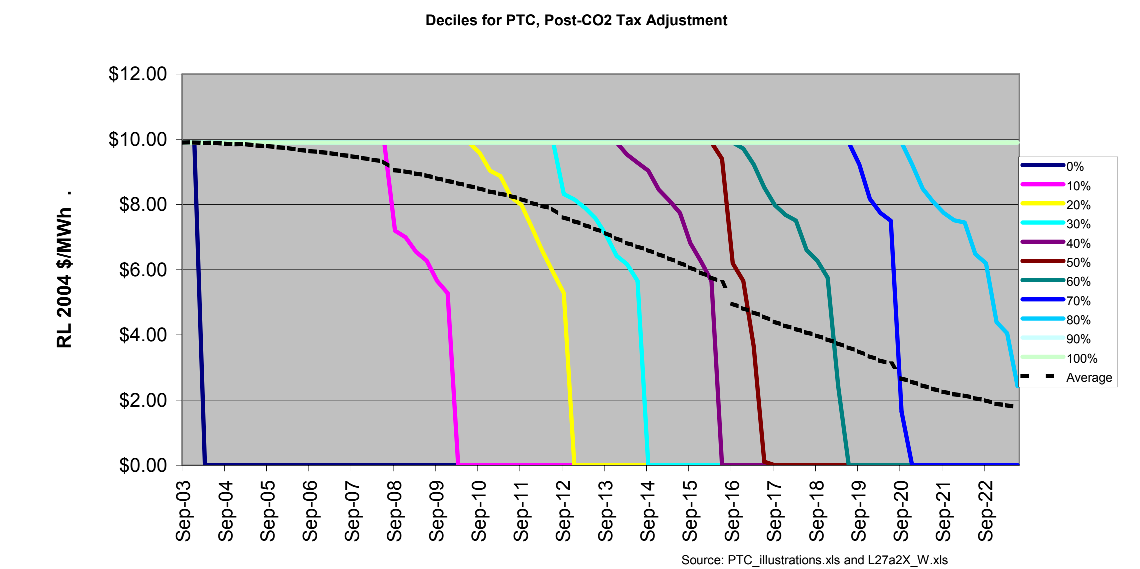



**Figure P-79: Deciles for PTC After the CO2 Tax Adjustment**

## Green Tag Value

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

In the model, green tag value can start the study period any where between $3 and $4 per megawatt-hour with equal likelihood (2004$). By the end of the study, the value can be anywhere between $1 and $8 per megawatt-hour (2004$). (See Reference [**30**].) A straight line between the beginning and ending values determines the value for intervening periods. Consequently, green tag value averages 3.50 at the beginning of the study and averages $4.50 at the end of the study. Uncertainty in the value increases over time. This value is unaffected by events such as the emergence of a carbon penalty or the termination of the production tax credit.

In the workbook, the green tag value is a simple linear function of time. First, the model draws of random variables for the starting value and the ending values. Figure P-80 illustrates the Crystal Ball assumption cells, {{R78}} and {{S78}}, respectively, responsible for providing those values.

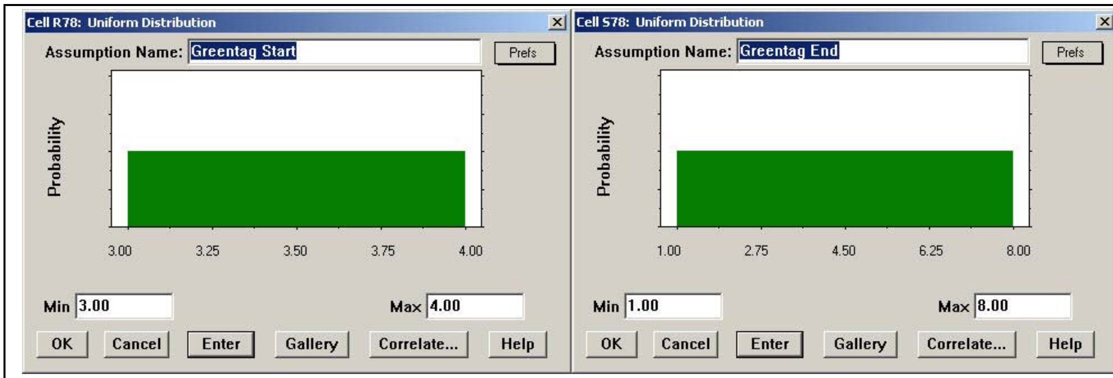
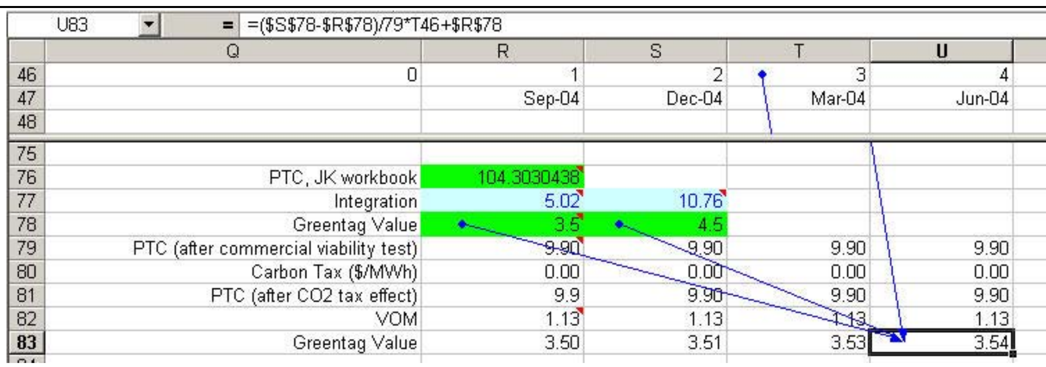



**Figure P-80: Green Tag Starting and Ending Values**

The model then creates a straight-line function over periods, as illustrated by the formula in Figure P-81.



U83 = =($S$78-$R$78)/79*T46+$R$78

| | Q | R | S | T | U |
|---|---|---|---|---|---|
| 46 | 0 | 1 | 2 | 3 | 4 |
| 47 | | Sep-04 | Dec-04 | Mar-04 | Jun-04 |
| 48 | | | | | |
| 75 | | | | | |
| 76 | PTC, JK workbook | 104.3030438 | | | |
| 77 | Integration | 5.02 | 10.76 | | |
| 78 | Greentag Value | 3.5 | 4.5 | | |
| 79 | PTC (after commercial viability test) | 9.90 | 9.90 | 9.90 | 9.90 |
| 80 | Carbon Tax ($/MWh) | 0.00 | 0.00 | 0.00 | 0.00 |
| 81 | PTC (after CO2 tax effect) | 9.9 | 9.90 | 9.90 | 9.90 |
| 82 | VOM | 1.13 | 1.13 | 1.13 | 1.13 |
| 83 | Greentag Value | 3.50 | 3.51 | 3.53 | 3.54 |

**Figure P-81: Formula for Green Tag Value Over Periods**

The decile summary for this stochastic variable is particularly uncomplicated and appears in Figure P-82:

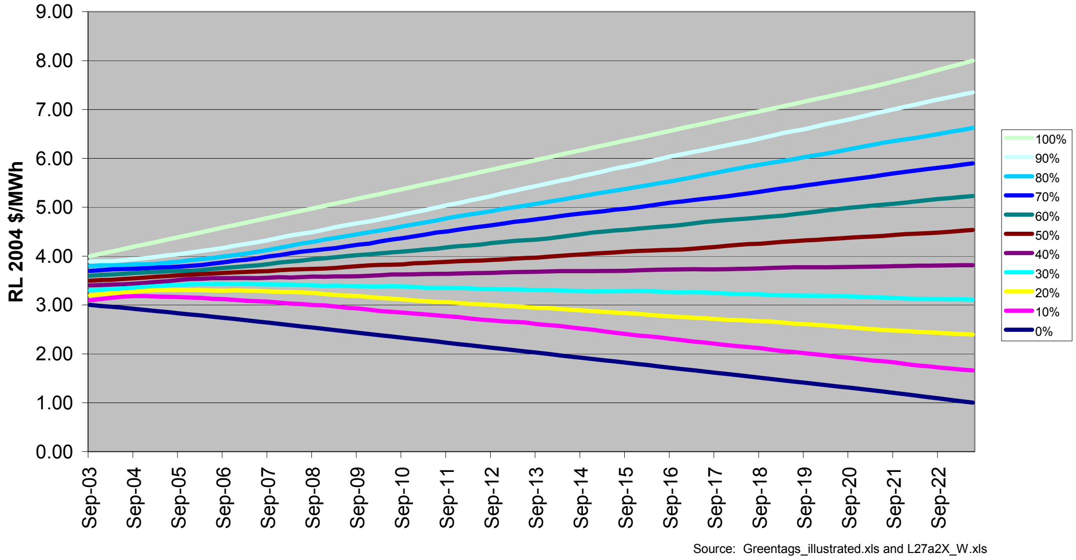



**Figure P-82: Deciles and Average for Green Tag Value**

Appendix L documents the final use for green tag value and how it is incorporated, along with PTC and variable operations and maintenance, into the cost of wind generation.

## Correlations

Correlations among variables are typically different at different time scales. For example, load may have positive correlation with electricity prices on an hourly time scale, but on an annual average scale have negative correlation. This negative correlation stems from demand elasticity. Consequently, this section deals with correlation among key variables at different time scales.

The regional model explicitly addresses three time scales. The first is hourly correlation, within a quarterly period, referred to here as intra-period correlation. The second is correlation of quarterly averages. The third is correlation that exists on the scale of multiple periods. The first situation has its own section below, while the second and third situations are combined. If it is essential to discriminate between the second and third types of correlation, the section distinguishes them in context.

There are also explicitly modeled correlations and those correlations that arise from assumptions, choices, and constraints in the model. The latter includes the relationship between electricity price and the amount of resource that is available due to the selection of a particular specific plan. (See the discussion of “RRP Algorithm” in Appendix L, page L-51.) It also extends to the relationship between electricity price and resource parameters, like the $CO_2$ tax. Because these relationships depend on variables that may or may not be representative for particular situations, however, this section does not attempt to characterize such correlations.

## Short-term Correlations

The correlation of values assumed within each period appears in Figure P-83. More accurately, these are correlations of values within each subperiod. The distinction is important. Note, for example, that there is no correlation assumed between hydrogeneration energy and load or between hydrogeneration and market price. In fact, as much hydrogeneration as possible is produced on peak, when market prices are high, which would result in high correlation. The solution to this apparent paradox is that the model already captures such correlation by distinct treatment of these variables in subperiods. The correlation table in Figure P-83, properly speaking, is any correlation net of subperiod modeling.

| | Market Price | Non-DSI Load Flat Energy | PNW West - NG Price | Hydrogeneration Energy |
|---|---|---|---|---|
| Market Price | 1.00 | 0.95 | 0.60 | 0.00 |
| Non-DSI Load Flat Energy | 0.95 | 1.00 | 0.00 | 0.00 |
| PNW West - NG Price | 0.60 | 0.00 | 1.00 | 0.00 |
| Hydrogeneration Energy | 0.00 | 0.00 | 0.00 | 1.00 |

**Figure P-83: Correlation of Hourly Values**

Because of how the regional model captures energy and cost, any temporal correlation of a variable with itself (autocorrelation) at the hourly scale is not relevant. The value of thermal dispatch over a subperiod, for example, is the sum of hourly values.

Correlation of natural gas price with electricity prices is significant to estimating the cost and value of thermal dispatch, as well as a forecasting capacity factor. An hourly correlation of 60 percent is taken as representative. Because of the many sources of interaction between load and electricity market price this correlation is 0.95. All other correlations are zero. These values appear in the regional model at range {{R14:T16}}, shown below (Figure P-84). Because hydrogeneration has no correlation with the other variables, its presence is not necessary. Because the correlation matrix is symmetric, this table includes only the values above the diagonal.

| | Market Vol Price | Non-DSI Load Flat Vol | PNW West - NG variable cost vo |
|---|---|---|---|
| Market Vol Price | 1 | 0.95 | 0.60 |
| Non-DSI Load Flat Vol | | 1 | 0.00 |
| PNW West - NG variable cost vol | | | 1 |

**Figure P-84: The Regional Model's Correlation Table**

## Long-term and Period Correlations

There are essentially three, explicit long-term correlations: the effect of natural gas price, loads, and hydrogeneration on electricity price; the effect of electricity price on loads; and the autocorrelation (chronological correlation) of variables with themselves. The regional model handles correlations of period averages for distinct variables through sensitivities, that is, a linear adjustment of one variable's average by another variable's average. It captures autocorrelations either through principal factors (Page P-28) or, in the case of aluminum price, through GBM coefficients (Page P-25).

Modeling correlation between averages of distinct variables as sensitivities is consistent with the correlation simulation described in the section "Simulating Values for Correlated Random Variables" on page P-26. Recall that for electricity, there remains a significant random term, the "independent" term, which provides uncorrelated behavior.

This appendix describes the effect of natural gas price, loads, and hydrogeneration on electricity price in section "The Influence of Loads, Natural Gas Price, and Hydro Generation," beginning on page P-72. It outlines the effect of electricity price on loads in the treatment of electricity price uncertainty, under the subsection "The Application to Load Elasticity," starting on page P-76.

# Risk Measures

This chapter describes risk measures and the treatment of risks. It begins with a discussion of risk measures generally and considerations that led the council to select the risk measure used in the regional model, $TailVaR_{90}$. It examines alternative risk measures and explains how each one relates to the $TailVaR_{90}$ risk measure.

This examination leads us to the following observations. Mean costs and $TailVaR_{90}$ do a reasonable job of screening plans. For modeling the regional portfolio, there is a strong consistency between the chosen measures and the alternatives in most cases. This correspondence is not accidental. It probably does not hold for individual utilities. The correspondence stems from the impact that adding substantial amounts of regional resources can have on regional prices. Individual utilities, on the other hand, are typically price takers whose supply actions do not affect market prices.

## Background

It may be useful to define what the Council means by risk.

***Risk is a measure of the expected severity of bad outcomes.***

A specific example of a measure of risk, therefore, is the average of outcomes in the "bad" tail of a distribution of costs, as illustrated in Figure P-85. In this case, bad outcomes are outcomes that are more expensive. This definition distinguishes the Council's risk measure from several in common use. For example, some use the standard deviation of the distribution of outcomes as a risk measure. The standard deviation, however, does not measure bad outcomes per se. The Council considers the standard

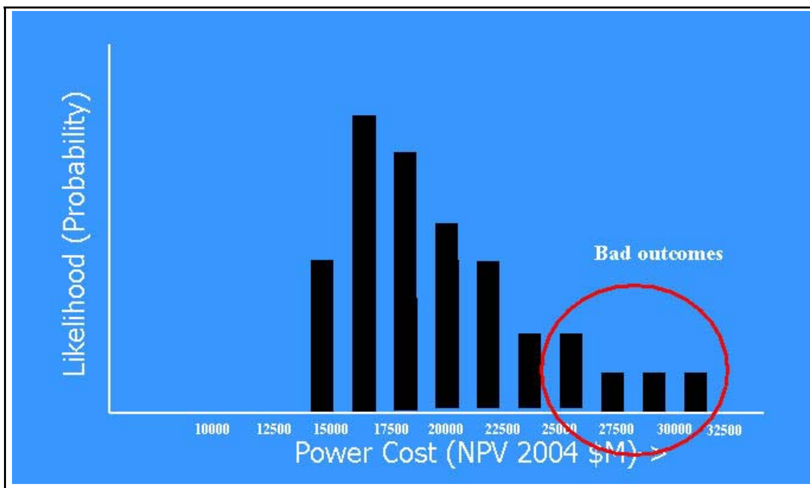



**Figure P-85: Bad Outcomes**

deviation a measure of predictability, not risk.

There are several reasons for the selection of this definition of risk. First, the Council believes a measure should not penalize a plan because the plan produces less predictable, but strictly better outcome. Consider, for example, Plan A and Plan B, which have cost outcomes distributed as illustrated in Figure P-86. Plan B has more predictable outcome but every outcome is worse (more expensive) than any outcome for Plan A. The Council would not consider Plan A riskier than Plan B. Even if the distributions overlapped, but for each future (game) Plan B did worse than Plan A, the Council would not consider Plan A riskier than Plan B.

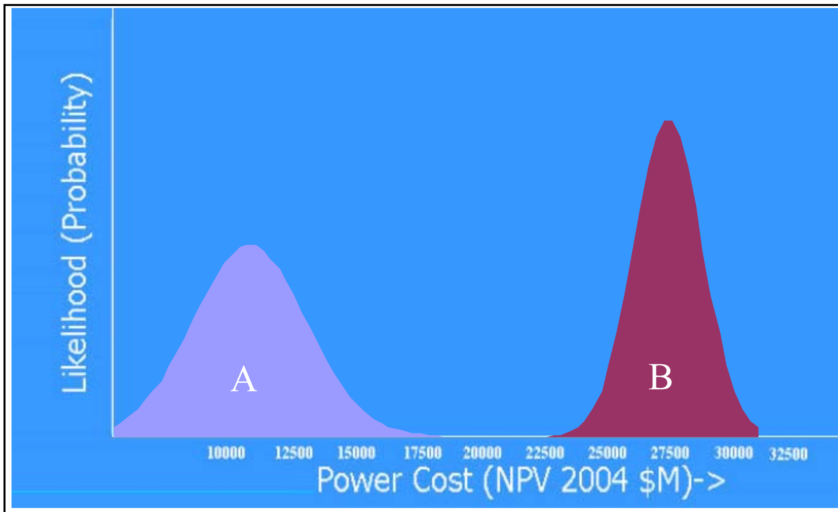



**Figure P-86: Plans A and B**

When confronted with situations like that which Figure P-86 illustrates, it is tempting to dismiss the problem because the average costs for Plan B are obviously worse than those for Plan A. No decision maker, it is argued, would fall into the trap of choosing the "less risky" Plan B over Plan A. That may be true in this situation, but consider the following example.

One plan produces the distribution of costs shown in Figure P-85; another plan creates the distribution in Figure P-87. (The section discussing cost distributions for the regional study, below, describes the characterization of these distributions as "price taker, with surplus plan and deficit plan.") The distributions are mirror images of one another, reflected around the mean. Because they are mirror images of each other, they obviously have the same average cost and standard deviation. A decision maker using average cost and standard deviation would therefore not be able to discriminate between them. Comparing the distributions directly, however, reveals that the first distribution has much greater likelihood of bad outcomes than the second. (See Figure P-88). The Council would consider the first plan riskier than the second.

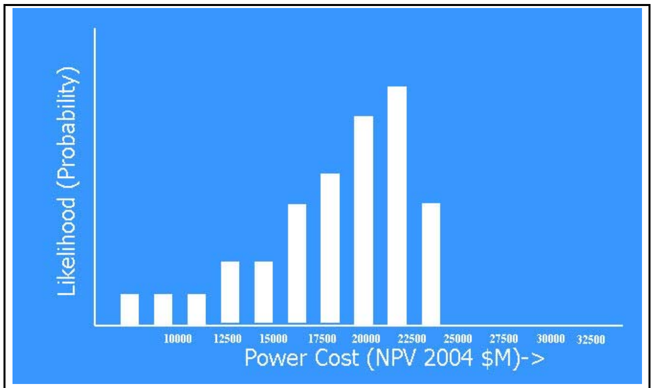



**Figure P-87: Cost Distribution for Price Taker with Surplus Resources**

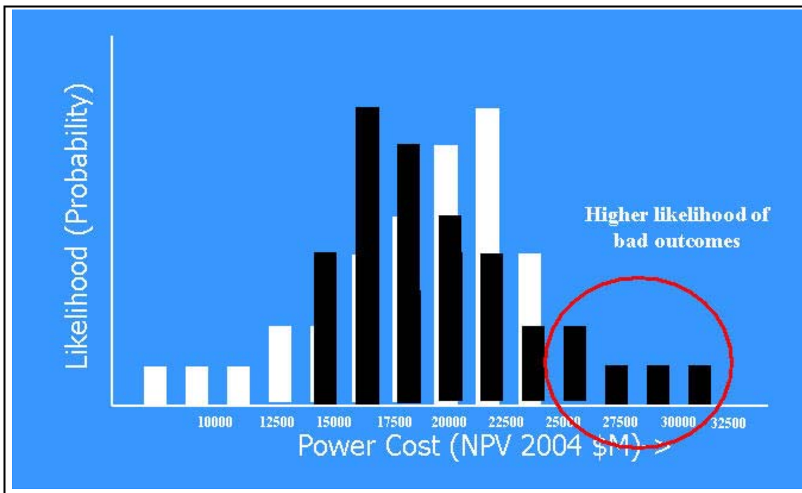



**Figure P-88: Cost Distributions for a Price Taker, a Resource-Surplus Plan (white) and Resource-Deficit Plan (black)**

Another reason to choose the definition of risk that the Council has is because it can be less expensive to reduce only expected severity of bad outcomes. Homeowner's fire insurance, for example, limits the economic damage that would otherwise take place in an accident. The insurance premiums, however, are typically much less expensive than the alternative of fire-proofing the home and its contents.

Finally, improving predictability, reducing the standard deviation, may come at the cost of eliminating good outcomes as well as bad. In the example of fire insurance, for example, neither the fire insurance nor the alternative of fireproofing the home improve the outcome in fortunate circumstances. Either there is a premium to pay or the cost of fire-proofing. The cost of fireproofing, however, impacts good outcomes much more.

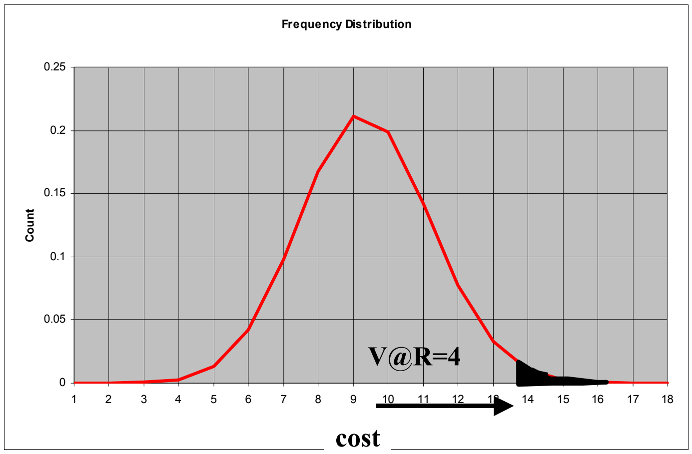



**Figure P-89: Value at Risk**

Some measures of risk recognize the logic of reducing bad outcomes but fall short in other regards. Value-at-Risk or VaR (sometimes V@R) is an example. Value-at-risk is a risk measure popular with investment and trading companies. VaR estimates the loss on a portfolio possible over a given period. Specifically, $VaR_{95}$ is the loss exceeded with less than five percent likelihood. The loss is usually relative to some benchmark, such as the mean of the distribution. In Figure P-89, the probability distribution represents the possible costs[36] associated with a project over the next month, denominated in millions of dollars. The black tail of the probability distribution represents five percent of the area, and the 95$^{th}$ quantile is \$13.5M. If the expected cost is \$9.5M, the VaR is \$4M.

The problem with VaR is that is does not capture the value of portfolio diversification. To illustrate this, consider a simple situation where the good outcome has zero cost and the bad outcome has a cost of \$1. Consider two instruments ($\boldsymbol{X_1}$ and $\boldsymbol{X_2}$) with independent but identically distributed costs, sampled across ten futures (games) as shown in Figure P-90. Each instrument has a one-in-ten chance of producing a bad outcome. Each instrument has a $VaR_{85}$ of zero, because more than 85 percent of the outcomes are zero (or less). The portfolio comprised of combining these two independent instruments, however, has a $VaR_{85}$ of 1.0, which is a riskier VaR level. That is, the portfolio is riskier, as measured by $VaR_{85}$, than the individual instruments! This is contrary to the concept of diversification.

[36] Note that we could have used the example of losses on a portfolio of investments, operating expenses incurred by a company, or a host of other cases. The principle of measuring bad outcomes is the same.

| Future | $X_1$ | $X_2$ | $X_1+X_2$ |
|---|---|---|---|
| 1 | 0.00 | 0.00 | 0.00 |
| 2 | 0.00 | 0.00 | 0.00 |
| 3 | 0.00 | 0.00 | 0.00 |
| 4 | 0.00 | 0.00 | 0.00 |
| 5 | 0.00 | 0.00 | 0.00 |
| 6 | 0.00 | 0.00 | 0.00 |
| 7 | 0.00 | 0.00 | 0.00 |
| 8 | 0.00 | 0.00 | 0.00 |
| 9 | 0.00 | 1.00 | 1.00 |
| 10 | 1.00 | 0.00 | 1.00 |
| VaR@85% | 0.00 | 0.00 | 1.00 |

$$0 = VaR(X_1) + VaR(X_2) < VaR(X_1 + X_2) = 1$$

**Figure P-90: Outcomes for Two Instruments in a Portfolio**

The problem with VaR is it gives no indication of *how bad* the outcomes are within the bad tail. In fact, any risk measure that reports only statistical quantiles suffers this problem.

## Coherent Measures of Risk

Experts in investment and risk management recognized the problems just described, and in the 1990s produced a class of risk measures that addressed them.[37] A ***coherent*** measure $\boldsymbol{\rho}$ of risk is a function from outcome distributions to the real numbers. It has the four mathematical properties below. These properties make the measure useful for properly ranking choices. They also address the issues raised above. The property of Monotonicity, for example, guarantees that if all of the outcomes for a given plan are better, then that plan will not have greater risk. The property of Subadditivity guarantees that portfolio diversity reduces risk. In the following, $\boldsymbol{\lambda}$ and $\boldsymbol{\alpha}$ are real number-valued constants.

[37] In 1999, Philippe Artzner, Universite Louis Pasteur, Strasbourg; Freddy Delbaen, Eidgen*f*ossische Technische Hochschule, Zurich; Jean-Marc Eber, Societe Generale, Paris; and David Heath, Carnegie Mellon University, Pittsburgh, Pennsylvania, published “Coherent Measures of Risk” (***Math. Finance*** 9 (1999), no. 3, 203-228) or http://www.math.ethz.ch/~delbaen/ftp/preprints/CoherentMF.pdf

- Subadditivity – For all random outcomes (losses) X and Y,
$$\rho(X+Y) \leq \rho(X)+\rho(Y)$$
- Monotonicity – If $X \leq Y$ for each future, then
$$\rho(X) \leq \rho(Y)$$
- Positive Homogeneity – For all $\lambda \geq 0$ and random outcome X
$$\rho(\lambda X) = \lambda\rho(X)$$
- Translation Invariance – For all random outcomes X and constants $\alpha$
$$\rho(X+\alpha) = \rho(X) + \alpha$$

The Council's measure of risk, $\text{TailVaR}_{90}$, is coherent [**31**]. It is defined to be the average of the ten percent worst outcomes, as illustrated in Figure P-91.

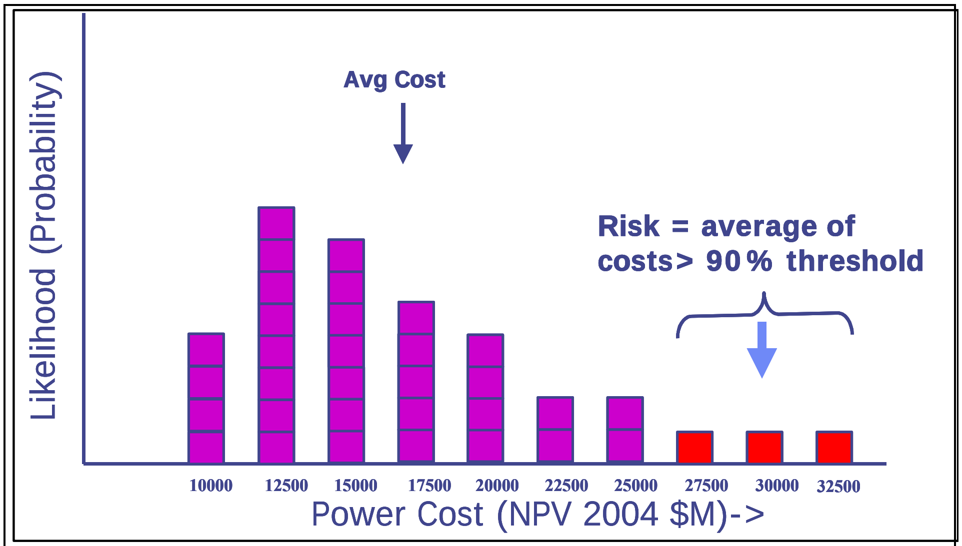



**Figure P-91: Plan Cost Distribution, Average Cost and Risk (TailVaR90 )**

$\text{TailVaR}_{90}$ is a measure of risk associated with *economic efficiency*. The Northwest Power and Conservation Council is required to develop a 20-year power plan under the Pacific Northwest Electric Power Planning and Conservation Act to assure the region of an adequate, efficient, and reliable power system. Previous and current Council studies use net present value (NPV) as a measure of economic efficiency. NPV is demonstrably better for this purpose than alternatives, such as B/C ratios and internal rate of return (IRR). Because the primary measure is one that relies on NPV, it stands to reason that bad outcomes are those with unfavorable NPV. Consequently, $\text{TailVaR}_{90}$ is fashioned to measure the expected severity of unfavorable NPV.

$TailVaR_{90}$ distinguishes between the two distributions illustrated in Figure P-88. It reasonable to expect, therefore, that the results obtained using this measure would not compare well with those obtained using a non-coherent measure of risk, like standard deviation. Surprisingly, non-coherent and coherent measures give comparable results in regional studies. The next section explains why this is so.

## Distributions of Cost for Regional Study

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

An example of the cost distribution situation for price takers with surplus resources appears in Figure P-85, reproduced here as Figure P-87. The source of risk for utilities with surplus resources is low market prices for electricity. With low market prices, the utility and its customers are better off if the utility buys its electricity from the market. This leaves the utility with the cost of "stranded resources," that is, plants that customers are still paying for but are not using. The size of this risk may be large, but it is limited.

Market price for electricity may go down significantly, but it obviously cannot go below zero. This means costs beyond meeting requirements out of market purchases will not be greater than the fixed costs of unused resources. Therefore, total costs have an upper bound, as illustrated in simple example shown in Figure P-92.

Figure P-92 shows the total costs of a simple system over a period, say a year, if electricity prices remained fixed at the value on the horizontal axis. This system has a load, and there is a cost of meeting that load in the electricity market. The dark purple, dotted line illustrates that cost. The system has a single generator that costs $50M/year in fixed costs and a dispatch price[38] of $30/MWh. Significantly, the size of the generator is twice the size of the load. The generator costs are the solid, dark blue line. When electricity price exceeds the generator's dispatch price, the generator creates value that offsets its fixed costs. The value of the generator in the electricity market increases dollar for dollar, with each dollar that the electricity price exceeds the dispatch price. The total costs, shown by the solid yellow line, are maximum at the dispatch price of the turbine. For prices higher than that, the turbine value offsets the cost of serving the load; for lower prices, lower purchase costs reduce total cost.

[38] The dispatch price is the electricity price that would cause the generator to just cover the cost of fuel and any other cost of operation that depends only on the amount of energy generated.

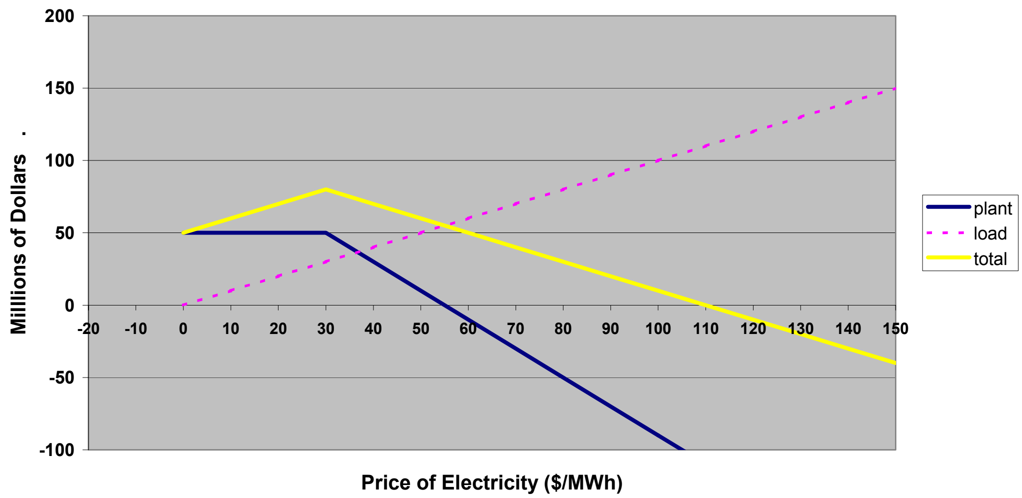



**Figure P-92: Example of Total Costs for a Simple Surplus System**

If electricity prices were fixed, the total cost could be read off the vertical axis of Figure P-92. For electricity prices that have a distribution instead of being fixed, however, there is a corresponding total cost distribution. The cost distribution has a tail extending to the left (*lower* costs) in Figure P-87, corresponding to *higher* electricity prices, because of the relationship shown in Figure P-92. Net costs can even become negative if prices are high enough, as Figure P-92 suggests.

The cost distribution situation for price takers with *deficit* resources is similar, except costs are now bounded below and *unbounded above*. For the simple example illustrated in Figure P-93, the load is larger than the plant. Now, however, *higher* costs correspond to *higher* electricity prices. If electricity prices have lognormal distribution, the distribution will have an unbounded tail extending to higher prices. This situation leads to a total cost distribution resembling that in Figure P-94. That cost distribution now has a tail pointing in the direction opposite that of Figure P-87.

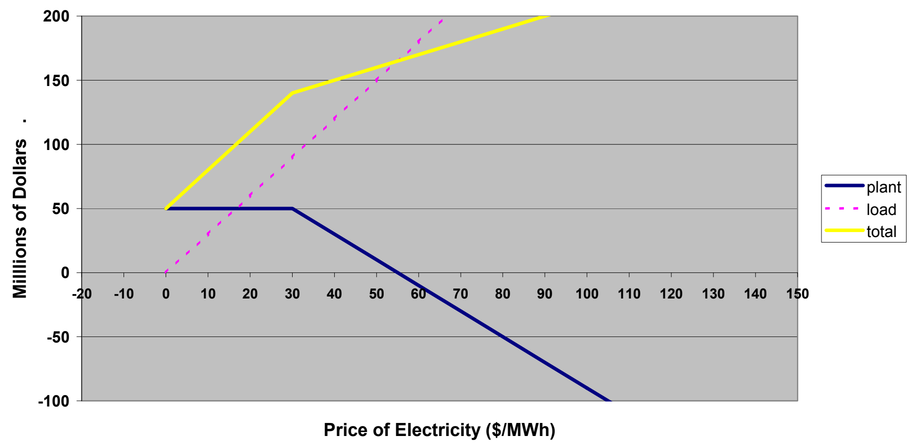



**Figure P-93: Example of Total Costs for a Simple Deficit System**

The region's cost distribution, it turns out, never resembles that for the surplus system. The preceding examples assume that utilities are price-takers, that is, the utility's surplus does not dampen electricity market prices. The aggregate regional resource situation, however, can affect market prices. Resources surplus to the regions requirements, after

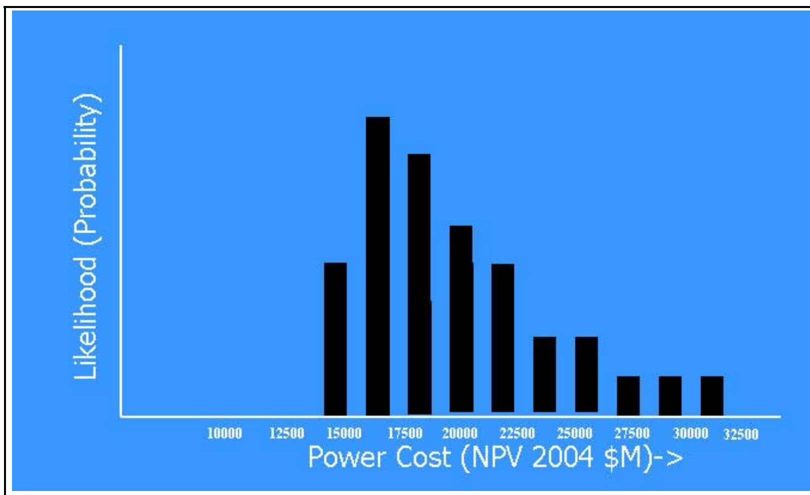



**Figure P-94: Cost Distribution for Price Taker with Deficit Resources**

exports, depress price. Effectively, the price range in Figure P-92 is capped on the high side, trapping the costs in positive territory. The final distribution for costs will tend to be more symmetric in this case than it would be for a deficit region. The width of the distribution may become quite small, but the mean will go up due to fixed costs. The "good" tail that is present in Figure P-87, however, does not materialize.

Because distributions like that in Figure P-87 never arise in the regional study, the mean cost is higher than the median cost. This has relevance to the question of the metric chosen for central tendency. Some would argue that the median is a better measure of central tendency than the mean for risk analysis. The next section is a brief digression from the topic of risk measures to address that issue.

## Median and Mean Costs

Is the median is a better measure of central tendency than the mean for risk analysis? The median future is a future above and below which lie an equal number of better and worse futures. In contrast, a weighing scheme defines the mean: the mean is the average of outcomes, weighed by their probabilities. What future will the region face? For that matter, what determines the outcome of rolling dice? It is a matter of the likelihood of landing on each face, not the value of the faces. The mean cost, in fact, may not correspond to any particular future, just as there is no face on a die with the value 3.5, the average outcome. For an odd number of futures, however, there is always a median value future[39]. This all tends to argue for the use of the median.

On the other hand, the mean is a statistic with which most decision makers seem to have greater comfort. Some decision makers may feel that they want extreme outcomes to influence their measure of the central tendency. The Council chose the mean to a certain extent because it is simpler to communicate than the median.

Fortunately, it does not make much difference which of the two measures of central tendency we choose. Distributions for outcomes of plans exhibit a strong relationship between the two measures. Figure P-95 shows that the mean and median values track very closely.

The mean value is consistently above the median, reflecting the observation above that distributions have long tails extending in the high-cost direction, pulling up the mean. As costs go down, the skewing becomes more pronounced. This has implications to the discussion of risk measures. Moreover, what typically occurs is that the least-cost, highest-risk plan consists of relying on the market to meet requirements. In this case, of course, the distribution for regional costs becomes highly skewed. This explains why skewing becomes more pronounced in Figure P-95 at the lowest average cost.

In conclusion, while the median might be a better measure of the central tendency than the mean for decision making under uncertainty, using the mean will give the same results in terms of the construction of the feasibility space and selection of plans. For studies of regional costs, distributions are skewed in the same direction as resource-deficit plans and the mean and median have a strong relationship.

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

This section suggests that, because distributions for regional cost are always skewed in one direction, non-coherent measures like standard deviation might give comparable results to those obtained by $TailVaR_{90}$. Returning to the topic of risk measures, next section addresses the question of, how representative is $TailVaR_{90}$?

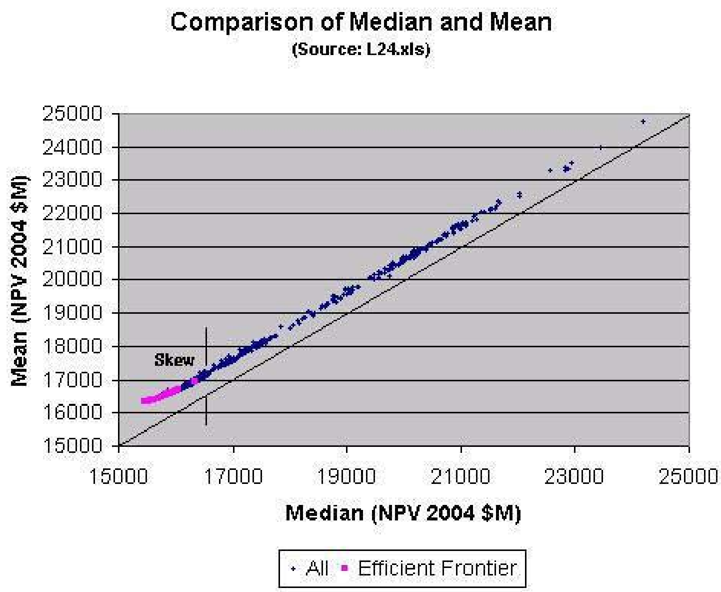



**Figure P-95: Mean versus Median**

# Perspectives on Risk

Many alternatives exist for measuring the risk. Each study performed with the regional model recorded a host of alternative risk measures, as well as both the mean and median cost. Figure P-96 illustrates the standard report, which Appendix L describes in detail. Risk measures for each plan appear on the right-hand side of this report and include:

- $TailVaR_{90}$
- Standard deviation
- $CVaR_{20000}$
- $VaR_{90}$
- $90^{th}$ Decile
- Mean (over futures) of maximum (over 20 years) of annual cost increases
- Mean (over futures) of standard deviation (over 20 years) of annual costs

(The figure simplifies the report, leaving out some columns and rows, to provide a more comprehensive view of the report.) Subsequent, out-board studies examined alternative sources of risk, such as relative exposure to bad market conditions and variation in average power cost.

This section reviews this information, extracted from the final Plan. This section asks

- How representative of alternatives is $TailVaR_{90}$? Would the Council have made a different choice of plans if it had used some other measure of economic risk?
- Given that the Council chooses a plan from among those on the efficient frontier, do other measures help the selection?
    - o How do conventional measures of reliability, like loss-of-load probability (LOLP), vary along the frontier?
    - o Do other perspectives on risk, such as cost volatility, give us a way to further refine the selection?

| | A | B | C | D | E | AQ | AR | AS | AT | AU | AV | AW | BG | BH | BI |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ******************************************** | | | | | | | | | | | | | | |
| 2 | * Analysis of * | | | | | | | | | | | | | | |
| 3 | * OptQuest.log * | | | | | | | | | | | | | | |
| 4 | * with * | | | | | | | | | | | | | | |
| 5 | * Analysis of Optimization Run_L27A2.xls * | | | | | | | | | | | | | | |
| 6 | ******************************************** | | | | | | | | | | | | | | |
| 7 | Sim | Cnsrvn_Lo | Cnsrvn_Dis | RM | CCCT_C | GCC_CY1 | IGCC_CY1 | Mean | Std_Dev | Median | TailVaR90 | CVaR20 | Cnsv_Cst: | Mean | |
| 8 | 1706 | 0 | 5 | 0 | | 0 | 0 | 23647.44 | 6602.989 | 22295.37 | 37435.84 | 26851.5 | 22.61565 | F | |
| 9 | 1873 | 0 | 5 | 5000 | | 0 | 0 | 23653.11 | 6379.034 | 22272.49 | 36955.9 | 26707.6 | 22.48798 | F | |
| [illegible] | 1607 | 0 | 5 | 5000 | | 0 | 0 | 23730.78 | [illegible] | 22396.39 | 36729.42 | 26541.8 | 22.38016 | F | |
| 122 | 1233 | 10 | 5 | 5000 | | 425 | 425 | 24430.97 | 5596.721 | 23208.61 | 35880.81 | 26168.4 | 22.92024 | F | |
| 123 | 1234 | 10 | 5 | 5000 | | 425 | 425 | 24435.55 | 5593.984 | 23207.23 | 35880.22 | 26171.7 | 22.91977 | F | |
| 124 | 1232 | 10 | 5 | 5000 | | 425 | 425 | 24440.25 | 5591.099 | 23205.85 | 35879.08 | 26175.3 | 22.91493 | F | |
| 125 | 948 | 5 | 25 | 5000 | | 425 | 425 | 24508.42 | 5569.806 | 23311.89 | 35870.65 | 26202.5 | 24.06349 | F | |
| 126 | 3 | 0 | 0 | 0 | | 0 | 0 | 23661.51 | 6599.311 | 22301.92 | 37450.84 | 26836.8 | 22.24873 | | x |
| 127 | 1726 | 50 | 5 | 0 | | 0 | 0 | 23847.44 | 6496.037 | 22455.33 | 37438.75 | 26864.0 | [illegible] | | x |
| 1499 | 775 | 5 | 5 | 5000 | | 425 | 425 | 24420.24 | 5604.747 | 23205.11 | 35887.48 | 26191.7 | 22.41363 | | x |
| 1500 | 912 | 5 | 5 | 5000 | | 425 | 425 | 24686.57 | 5485.664 | 23486.43 | 35882.99 | 26243.5 | 22.25928 | | x |
| 1501 | 922 | 5 | 25 | 5000 | | 425 | 425 | 24459.83 | 5598.099 | 23261.39 | 35881.38 | 26237.1 | 24.06979 | | x |
| 1502 | 1230 | 10 | 5 | 5000 | | 425 | 425 | 24467.54 | 5575.609 | 23260.49 | 35880.23 | 26198.7 | 22.90646 | | x |
| 1503 | 60 | 50 | 50 | 0 | 12 | 1700 | 1700 | 31340.27 | 6122.014 | 29994.17 | 44043.84 | 31386.0 | 29.59224 | | |
| 1504 | 24 | 50 | 50 | 0 | 12 | 1700 | 1700 | 30878.93 | [illegible] | 29537.35 | 43619.37 | [illegible] | 29.59777 | | |
| 2009 | 264 | 35 | 30 | 5000 | | 425 | 425 | 25013.59 | 5386.828 | 23829.93 | 35987.55 | 26329.6 | 26.69841 | | |
| 2010 | 807 | 15 | 5 | 5000 | | 425 | 425 | 25090.18 | 5395.79 | 24027.38 | 35985.2 | 26423.2 | 23.24394 | | |
| 2011 | 630 | 0 | 0 | 5000 | | 425 | 425 | 24824.09 | 5489.656 | 23716.65 | 35963.71 | 26344.6 | 21.46526 | | |
| 2012 | | | | | | | | | | | | | | | |

**Figure P-96: Alternative Risk Measures (Right Hand Side) from Appendix L**

The section first examines economic risk measures. These derive from distributions of net present value study costs and include coherent and non-coherent measures of risk. It then reviews measures of cost volatility. Cost volatility here refers to year-to-year variation in both going-forward costs and total costs, including embedded costs. It also refers to the consistency of factors that would affect rates, such as imports of expensive energy. Finally, the section addresses two conventional measures of engineering reliability, LOLP and resource-load balance.

## Alternatives to $TailVaR_{90}$

As explained earlier in this chapter, measures of NPV distribution are the most appropriate risk measures, given the task of the Council's Plan. Measures of NPV distribution are a kind of as "economic efficiency" risk. Among alternatives to $TailVaR_{90}$ for measuring such risk are 90th quantile, standard deviation, $VaR_{90}$. These examples happen to be non-coherent measures of risk. Even among coherent measures of economic risk, however, there are unlimited choices for such measures.

$CVaR_{20000}$, for example, is a coherent measure of economic risk, and earlier Council studies used it as the primary risk measure. $CVaR_{20000}$ is the average of costs exceeding $20,000 million. The concept is that if decision makers can deem an economic threshold as undesirable, the average of costs above that threshold makes a reasonable measure of risk.

$CVaR_{20000}$, however, has several shortcomings. Most important, the Council does not have an a priori vision of what that threshold should be. The $CVaR_{20000}$ measure even complicates the process of studying cost distributions to arrive at such a threshold. A distribution may shift dramatically with the introduction of new assumptions. If plan distributions for the base case and change case fall on one side or the other of the threshold, $CVaR_{20000}$ cannot discriminate between them. Finally, because the threshold is a subjective assessment by the decision maker, selecting a threshold introduces another assumption to defend and debate.

$TailVaR_{90}$ addresses these issues and affords additional benefits. Because the value of $TailVaR_{90}$ is never less than the 90th quantile, for example, the Council can make statements about the likelihood of "bad" outcomes. That is, futures with $TailVaR_{90}$ costs or greater are expected with less than 10 percent probability.

One measure of how well $CVaR_{20000}$ compares with $TailVaR_{90}$ is their correlation. If they produce the same rank of outcomes, they provide effectively the same information. If the two measures are plotted against one another, as in Figure P-97 [**32**], the points would fall on a strictly monotonic curve. (See, for example, Figure P-95.) The dispersion of points around the monotonic curve is an indication of their correspondence. Correlation is a measure of that dispersion. Figure P-97 suggests that the correspondence between $CVaR_{20000}$ and TailVaR 90 is rather weak, in general. The white points in the bottom left-hand corner of the distribution, however, correspond to the efficient frontier,

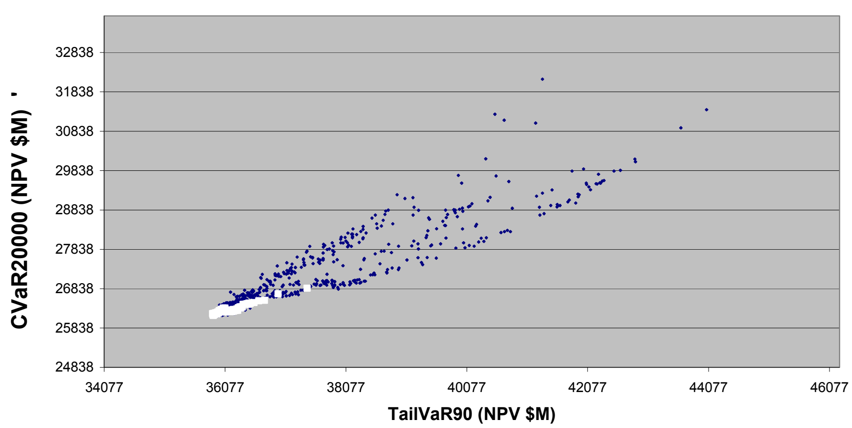



**Figure P-97: Relationship, CVaR20000 to TailVaR90**

using $TailVaR_{90}$. On that efficient frontier, the correspondence is quite good.

Figure P-98 reconstructs the feasibility space using $CVaR_{20000}$. Again, the white points are the efficient frontier constructed by using $TailVaR_{90}$. Evidently, it does not make any difference whether we construct the efficient frontier using $TailVaR_{90}$ or $CVaR_{20000}$.

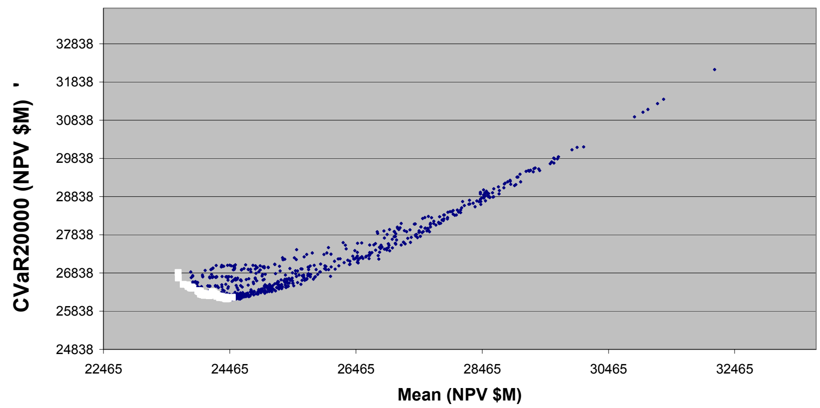



**Figure P-98: Feasibility Space, using CVaR20000**

<u>90th Quantile</u>

Non-coherent measures do not correspond well, in general, to $TailVaR_{90}$. Figure P-99 plots the 90th quantile against $TailVaR_{90}$. The relationship is clearly much weaker than for $CVaR_{20000}$. Figure P-100 makes it clear that the efficient frontier using the 90th quantile does not correspond to that using $TailVaR_{90}$. The efficient frontier using

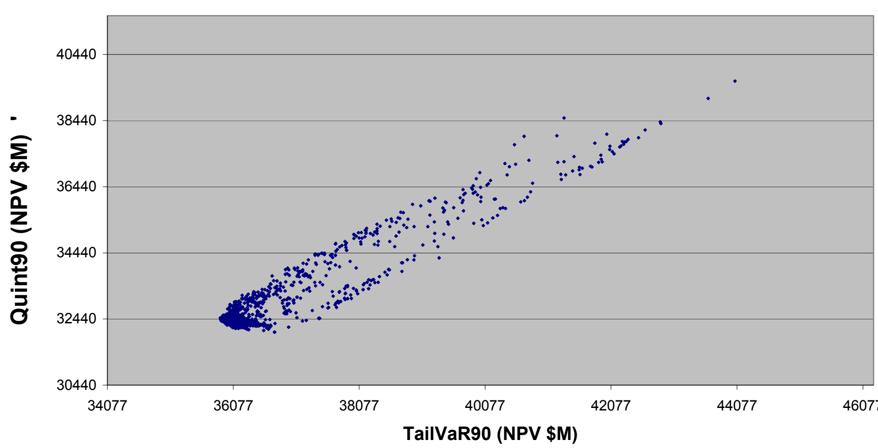



**Figure P-99: Relationship, 90th Quantile to TailVaR90**

$TailVaR_{90}$ is clearly well within the set of dominated points. It is reassuring, however, that the efficient frontier using $TailVaR_{90}$ is contained in the set of nearly efficient points using the 90th quantile. It appears that plans that are efficient with respect to $TailVaR_{90}$ are efficient, or nearly efficient, with respect to the 90th quantile.

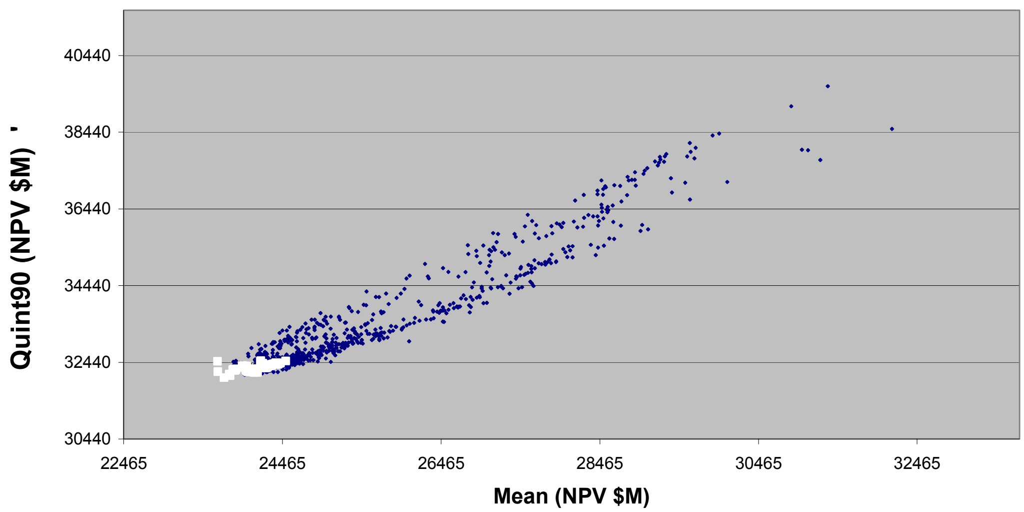



**Figure P-100: Feasibility Space, using 90th Quantile**

Standard Deviation

Standard deviation bears virtually no relationship to $TailVaR_{90}$, as illustrated in Figure P-101. Fortunately, because the cost distribution for the region is always skewed in the same direction, plans that are efficient using $TailVaR_{90}$ have least standard deviation for each level of cost. Consequently, those plans that are efficient using $TailVaR_{90}$ are also efficient using standard deviation, as Figure P-102 illustrates. In fact, the sequence of

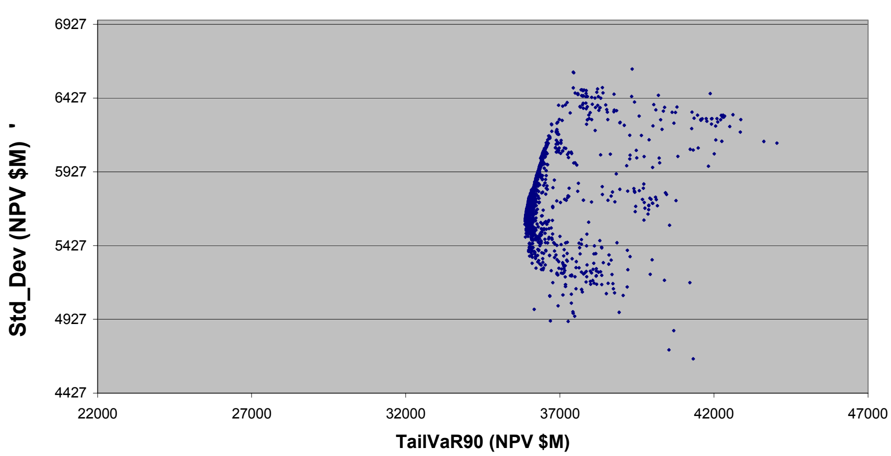



**Figure P-101: Relationship, Standard Deviation to TailVaR90**

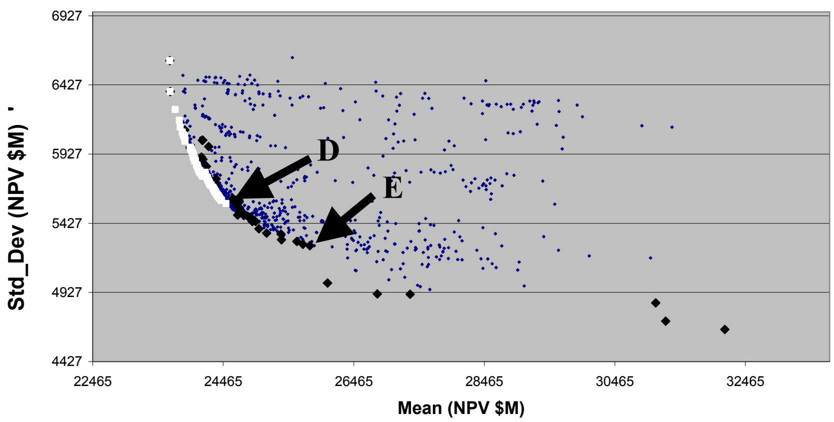



**Figure P-102: Feasibility Space, using Standard Deviation**

plans along the efficient frontier closely follows that for the efficient frontier using $TailVaR_{90}$. For example, the least risk plan, Plan D, is also least risk – among the white points – using standard deviation. (See Figure P-103.)

There are a good number of plans, identified by the black diamonds in Figure P-102, that are efficient with respect to standard deviation, but not efficient with respect to $TailVaR_{90}$. This raises the obvious question, "Would the council have selected another plan if they used standard deviation?"

It is unlikely that the council would have chosen any of the Black Diamond plans. The reason, simply stated, is that these plans to perform worse under a preponderance of futures than the plans corresponding to the white points.

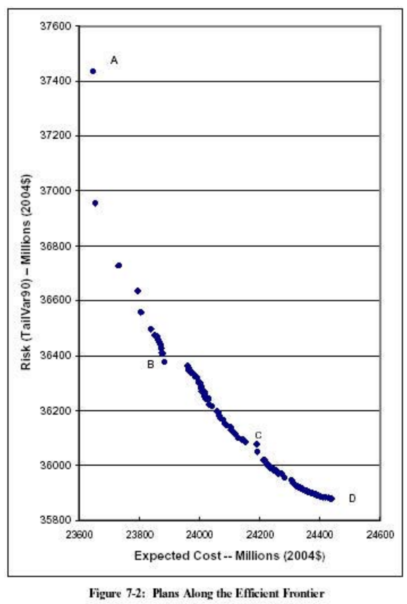



**Figure P-103: Chapter Seven's Figure 7-2**

For example, Plan E in Figure P-102 has substantially better standard deviation than Plan D ($380 million smaller). If we compare the total system cost of plan E in each future against the cost of the corresponding future for Plan D, we can construct the illustration of the sorted differences appearing in Figure P-104. While Plan E is more predictable as measured by standard deviation, it produces a better outcome in less than two percent of the futures. The number of futures with significant difference is half of that. In over 80 percent of the futures, the outcome for plan E is over $1 billion worse than that for Plan D. The ability of $TailVaR_{90}$ to discern plans that perform better in the vast majority of futures is directly related to the property of monotonicity shared by all coherent risk metrics.

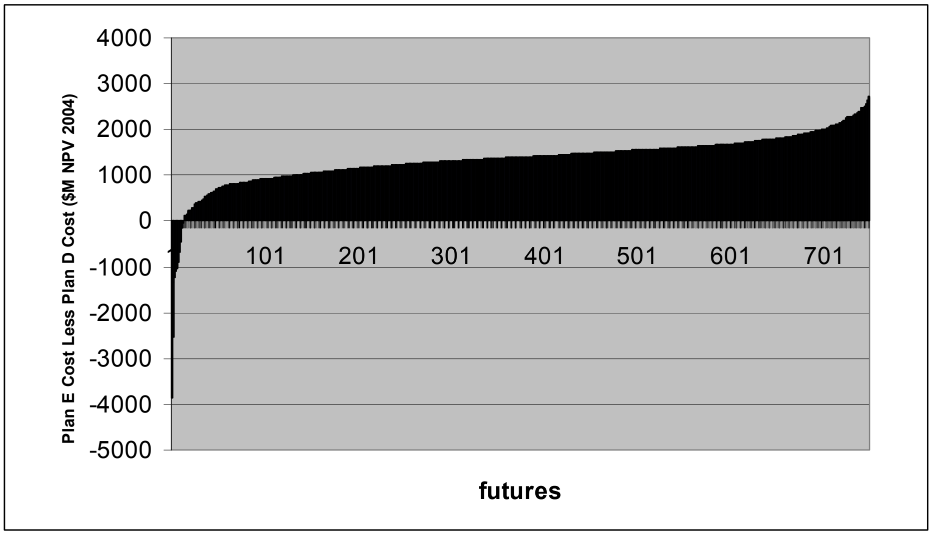



**Figure P-104: Cost Differences Between Plans D and E, by Future**

VaR$_{90}$

The definition of Value-at-risk (VaR) appears earlier in this chapter. It is a risk metric that, like standard deviation, primarily measures the width of the distribution. It should not be too surprising, therefore, that its correspondence to TailVaR$_{90}$ resembles that of standard deviation. (See Figure P-105.) The correspondence of the efficient frontier to that defined using TailVaR90 (white points) is not as clean as it is for standard deviation. Nevertheless, plans that are efficient with respect to TailVaR$_{90}$ are efficient or nearly efficient with respect to VaR$_{90}$. The efficient frontier in Figure P-105 below the white dots has the same explanation as the corresponding area for standard deviation. Once again, the conclusion is that it is unlikely the Council would have chosen plans from the efficient frontier of Figure P-105 below the plans illustrated with white points.

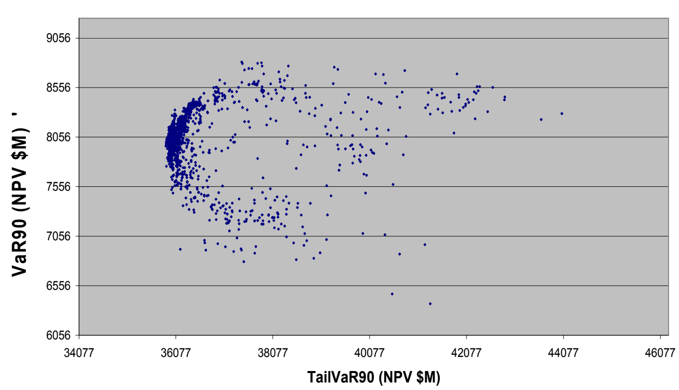



**Figure P-105: Relationship, VaR90 to TailVaR90**

## Cost Volatility

Economic efficiency can hide a multitude of sins. Costs over the study period can produce low net present value while still exhibiting large volatility. Cost volatility is undesirable because it can produce sudden and unexpected retail rate increases.

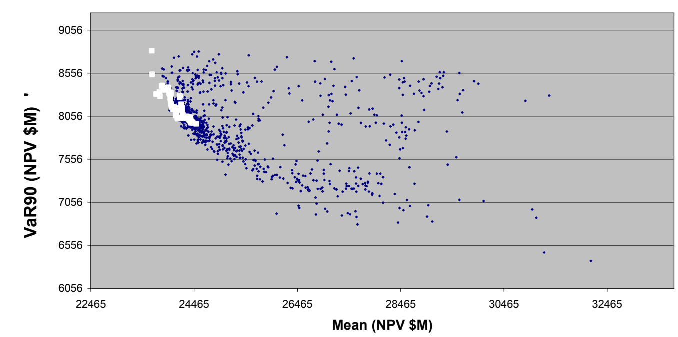



**Figure P-106: Feasibility Space, using VaR90**

There are several questions one can ask about cost volatility. First, how to the plans along the efficient frontier perform with respect to cost volatility relative to those plans that are not on the efficient frontier? Second, what kind of variation in cost volatility exists among plans on the efficient frontier? Third, what are some of the key drivers of cost volatility?

There are many ways to define cost variability. The next section considers several types of cost volatility and explains the purpose of each.

<u>Average Incremental Annual Cost Variation</u>

In Figure P-107, it is evident that the relationship between the mean cost variation and $\text{TailVaR}_{90}$ is quite weak. Mean cost variation is the average, across futures, of the standard deviations for changes in annual costs across the study. This tends to be a weak indicator of volatility for a couple of reasons. This standard deviation uses the first half of the study, when there are virtually no differences among plans. Averaging over futures tends to water down this metric as well.

There are a few things that we can discern, however, from Figure P-107. Plans on the TailVaR90 efficient frontier[40] (white points) all tend to lie in a narrow range of mean cost variation. That is, by this measure it does not really matter which plan from the efficient frontier we choose. It is also notable that there are many plans with less mean cost variation. These are associated with more expensive plans and surplus resources. Resource shortage and electricity market price volatility increase cost variability; surplus resources will lower cost volatility because they tend to dampen wholesale electric market prices.

[40] In this chapter, the $\text{TailVaR}_{90}$ efficient frontier refers to those plans that are on the efficient frontier if they were in a plot of plan mean cost against plan $\text{TailVaR}_{90}$.

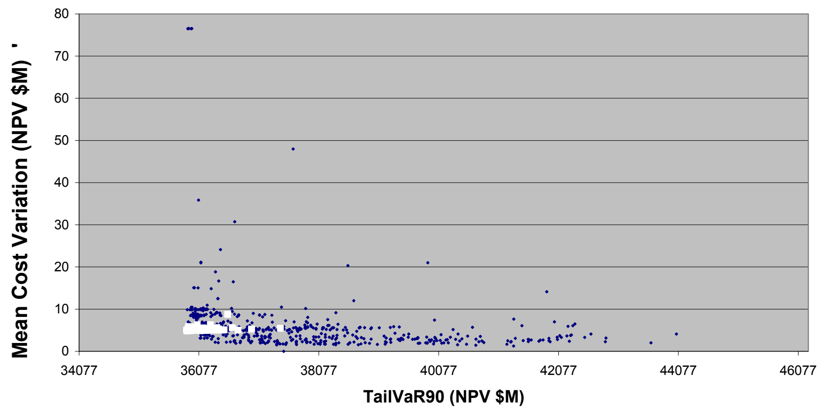



**Figure P-107: Relationship, Average Incremental Annual Cost Variation to TailVaR90**

Maximum Incremental Annual Cost Increase

A slightly more sensitive measure of cost volatility is the maximum increase in costs over the study. Figure P-108 compares the average maximum cost increase, across futures, to TailVaR$_{90}$. We still see roughly the same pattern that was evident for average incremental annual cost variation. If we expand the region around the TailVaR$_{90}$ efficient frontier, we can see that there is a very weak relationship between the two measures. Figure P-109 includes a regression line that emphasizes this weak relationship.

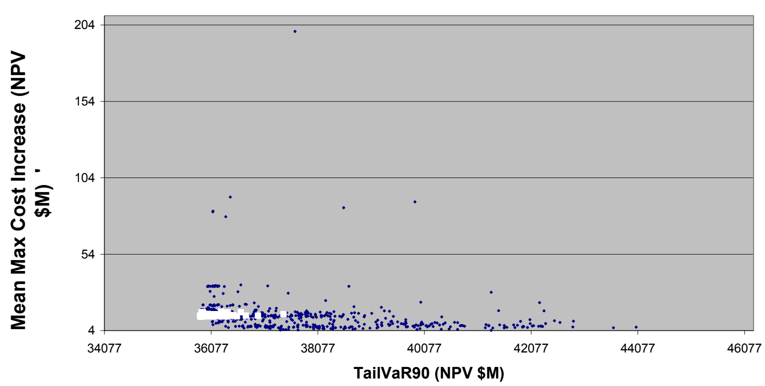



**Figure P-108: Relationship, Maximum Incremental Annual Cost Increase to TailVaR90**

Council Staff investigated several alternative measures for cost volatility. The next section describes several of the more successful results.

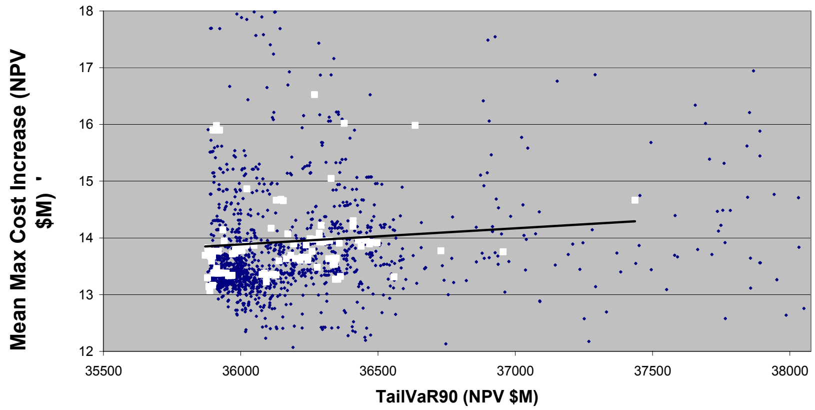



**Figure P-109: Magnification of Previous Figure**

Average Power Cost Variation (Rate Impact)

By parsing out the number of futures with increases that exceed in a given level, a more refined measure of cost volatility is possible. This section describes how the four scenarios identified in Figure P-103 perform under this measure.

Figure P-110 [**33**] shows the percent of futures where cost increases exceed the levels on the horizontal axis. While the preceding discussions of annual cost volatility used only variable costs and forward-going fix costs, Figure P-110 includes system embedded costs of about $7 billion per year[41]. Including this embedded cost reduces the cost volatility, compared to the statistics in the previous section, but it provides values that more closely correspond to total power costs and retail rates.

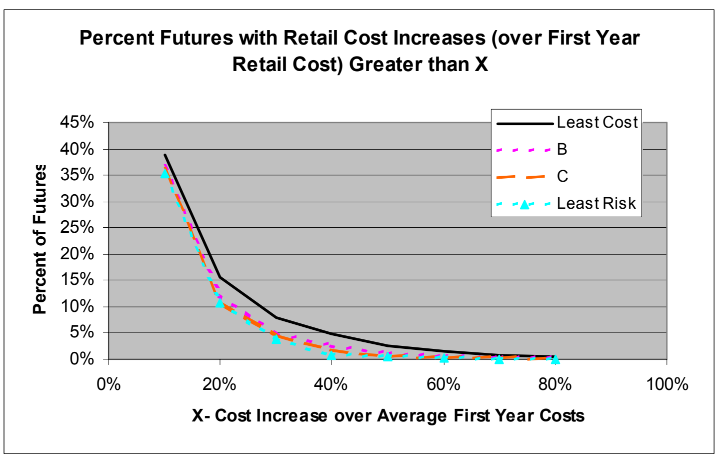



**Figure P-110: Exceedance Probability: Increase Over First Year's Cost**

[41] Staff attempted to adjust the embedded costs from year-to-year for depreciation. In real terms, these costs decreased by 3 percent per year.

In Figure P-110, the horizontal axis are cost increases calculated by dividing each year's costs by the costs in the first year the study:

$$\frac{C_i}{C_1}$$

This provides some insight into how the costs vary with respect to current circumstances. The graph suggests that there is significant improvement in moving from the least-cost plan A to Plan B. In particular, the likelihood of cost increases exceeding 30 percent is half of that for the least-cost plan. Plans B, C, and D (the least risk plan) all have comparable cost volatility.

An alternative way of measuring cost variation is to look at the difference in costs from year-to-year and compare that change to costs in the first year the study:

$$\frac{C_i - C_{i-1}}{C_1}$$

This provides an idea of rate shock, while "normalizing" the denominator. Without normalizing the denominator, cost increases expressed as percentage change would appear to be different when the change in annual cost expressed in dollars is the same. The results for this analysis appear in Figure P-111. They suggest the same conclusions as the previous figure, although the reduction in likelihood is now for percentage cost increases over 40 percent, instead of 30 percent.

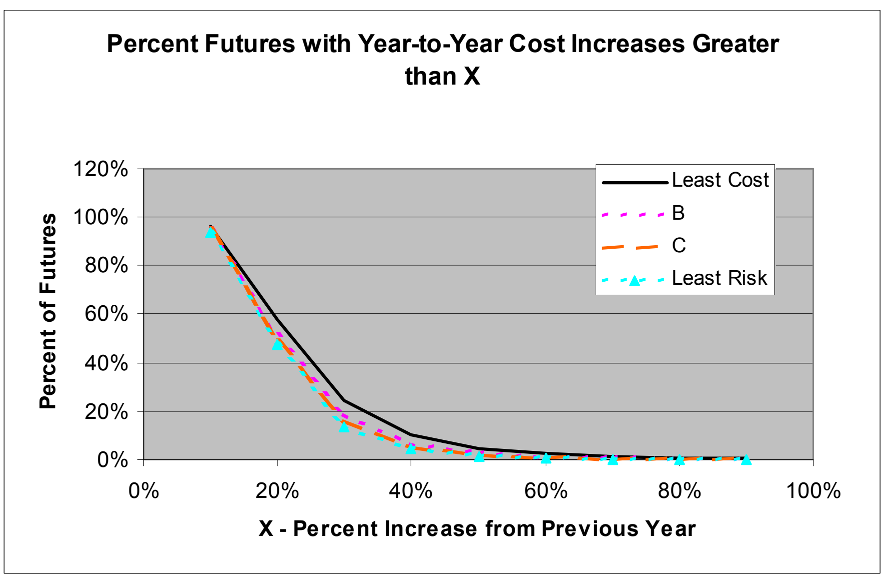



**Figure P-111: Exceedance Probability: Changes Over First Year's Cost**

Finally, Figure P-112 uses simple cost change from year-to-year:

$$\frac{C_i - C_{i-1}}{C_{i-1}}$$

The conclusions from this figure would be the same as the previous one.

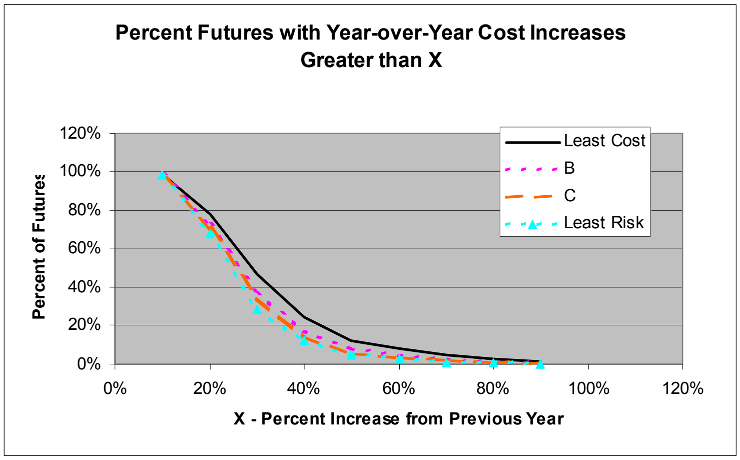



**Figure P-112: Exceedance Probability: Changes Over Previous Year's Cost**

By these measures, we see substantial reduction in cost volatility in going from the least-cost plan to any of the other three plans. Cost volatility among the three lower risk plans clearly decreases as $TailVaR_{90}$ risk decreases, but those three provide roughly similar results.

It is reasonable to ask what is driving the cost volatility. Figure P-107 and Figure P-108 suggests that the fix costs associated with new power plants are not the source of cost variation. In fact, plans with more resources seem to have less cost variation. This points to a source of risk that is prominent among the Council's concerns: electricity market price risk. While market price uncertainty can contribute to risk, it is not in itself a source of bad outcomes. The region needs to be a deficit situation and importing energy for high market prices to produce sudden increases in costs.

Imports and Exports

Figure P-113 [**34**] shows the difference in substantial imports between the least risk plan at least cost planned. For the purpose of this illustration, substantial imports are those exceeding 1500 MW-quarters. Imports are identical until about the year 2013, when power plants begin to appear in the least risk plan. As expected, there is more import in the least cost plan, exposing the region to high electricity market prices.

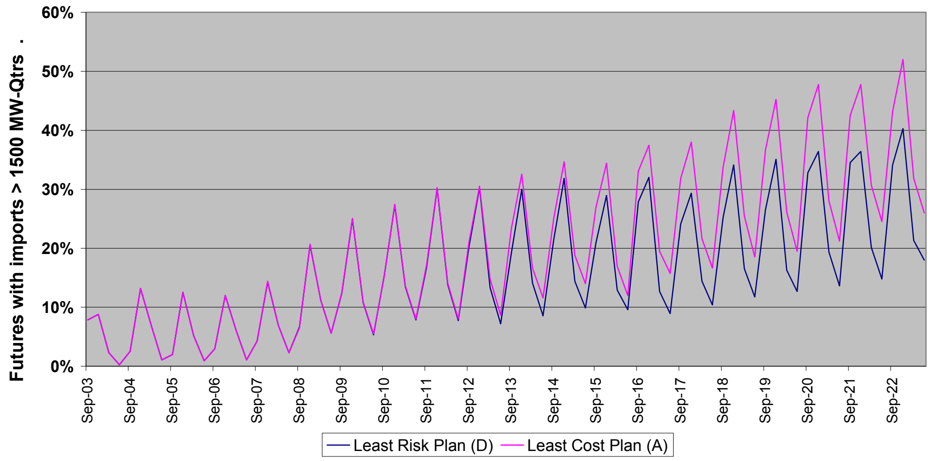



**Figure P-113: Frequency of Futures with Large Imports**

Exposure to Wholesale Market Prices

Figure P-114 [**34**] examines specifically those events where there are both substantial imports and high market prices for electricity (over $100 per MWh). This figure suggests several conclusions. The least-cost plan introduces substantially greater likelihood of incurring costs associated with high market prices than the least-risk plan. This is due to both the higher likelihood of high market prices with the least-cost plan and the higher likelihood of substantial imports. It is also notable that, with the least-risk plan the likelihood of regional exposure to wholesale market prices remains roughly the same throughout the study. Plan B reduces this likelihood by half, but not to the extent of the least-risk Plan D.

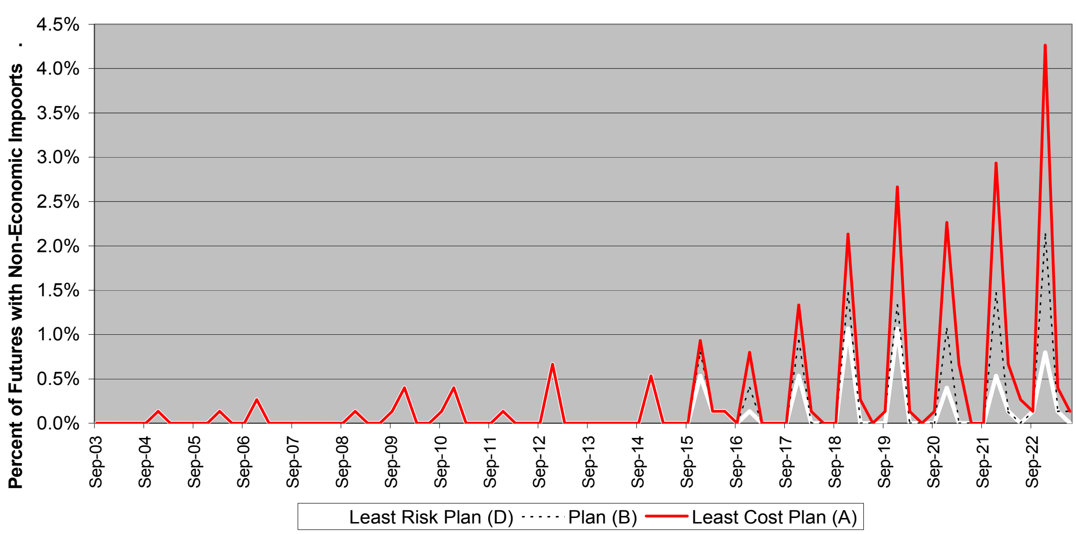



**Figure P-114: Likelihood of Exposure to Non-Economic Imports**

This concludes the analysis of cost volatility among plans in the feasibility space, and among plans on the efficient frontier, in particular. This analysis suggests that plans on the efficient frontier do not have the least cost volatility, but they do possess moderate cost volatility. Economically inefficient, resource-surplus plans have lower cost volatility. Among the plans on the efficient frontier, cost volatility decreases with plan risk, as measured by $TailVaR_{90}$. Most of the volatility, however, diminishes passing from the least-cost plan (Plan A) to Plan B (Figure P-103). Plan B has substantially more wind development than Plan A, and it lacks the IGCC plant and late CCCT development of Plans C and D.

## Engineering Reliability

Many of the concepts introduced with the regional model are new to decision makers in the regional power planning community. Economic risk metrics, in particular, may be unfamiliar. As we will see, economic risk metrics appear to be more sensitive than engineering risk metrics. Nevertheless, there is no guarantee that a plan that has good economic characteristics must have high reliability from an engineering perspective. It stands to reason that decision makers will want to confirm that plans along the efficient frontier meet traditional measures of engineering reliability.

<u>Energy Load-Resource Balance</u>

It is challenging to relate the results from the regional portfolio model to other system planning models. Other models cannot capture certain events and behaviors, such as the regional model's dynamic reaction to unforeseeable futures. To better communicate the results of the regional model, Council Staff nevertheless examined questions typically put to system planning models like, "What is the loss of load probability associated with this plan?" or "What kind of a energy resource-load balance does that plan produce?"

The last question is the genesis of this section. At first glance, answering the question should be easy. There is, after all, a plan of construction and an expected load forecast. The difference between these, expressed in energy, should characterize the resource-load balance, shouldn't it? Actually, no, because the plan is a schedule of earliest construction. Which and how many plants eventually come on-line and the energy requirement both depend on the future.

Moreover, because the plan is essentially a schedule of options to build resources, the number and size of resources grows relative to the expected load. That is, the energy resource-load balance – what we occasionally refer to as the "energy reserve" – is growing relative to the load. The reason for the growth in reserve is that, further out there is greater uncertainty. With growing uncertainty about fuels, loads, taxes, and so forth, it is becomes cost effective to have more options to respond to that uncertainty. That is, the plan may have both a coal-fired and a gas-fired power plant as options in outlying years because the model will develop one or the other, depending on circumstances, but presumably not both.

One way to make the regional model results to a certain extent comparable is to examine the energy reserve on a future-by-future basis. For the recommend Plan, a sample on annual energy reserve from the 750 futures appears in Figure P-115.

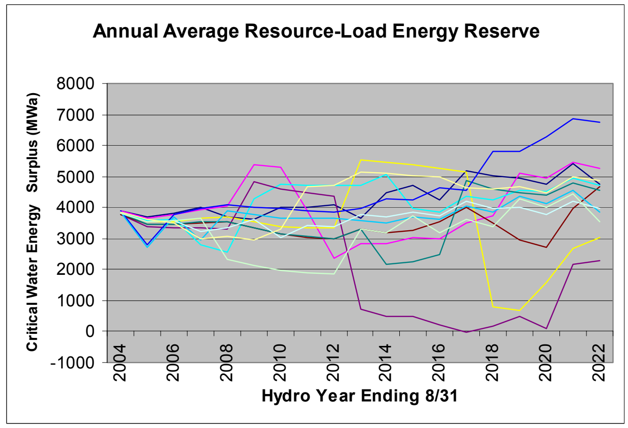



**Figure P-115: Resource-Load Balance for the Plan**

What the figure shows are 12 futures with wildly varying reserve margins, which can rapidly change from relatively high, positive values to negative values. These sudden excursions are typically associated with business cycles, the return or departure of smelters, changing contract levels, and power plants coming into service. A major sources of load and production variability, weather and hydrogeneration stream flows, do not influence this picture, however. This figure reflects a planning energy reserve margin. Planning studies typically disregard those sources of variation. Instead, this figure shows energy reserve margin using weather-adjusted loads and critical water assumptions. (Critical water is the lowest hydrogeneration energy due to historical stream flow variation.)

Figure P-115, however, does not provide a sense of what kind of patterns may exist over all the 750 futures. To see those patterns, statistical summaries are necessary. We emphasize again here that these statistical summaries may be misleading and require interpretation. (See the subsection "Comparison with the Council's Load Forecast" of the section of the Uncertainties chapter dealing with Load.)

Figure P-116 shows the recommended Plan's quarterly deciles for critical water energy reserve [**35**]. Chapter 7 of the Plan discusses four plans selected from along the efficient frontier. These plans are illustrated in Figure 7-2, which is reproduced below (Figure P-103) for easy reference. Figure 7-2 refers to the recommended Plan as Scenario D.

What is evident is from Figure P-116 is the median energy reserve stays about where it is today, perhaps a few hundreds of MWa higher. This is consistent with the observation that the region is currently surplus of resources, on an expected value basis. Also, the upper and lower bounds, the "jaws" so to speak, become wider farther along in time. This illustrates one of the facts highlighted earlier in this section: greater uncertainty merits greater contingency planning.

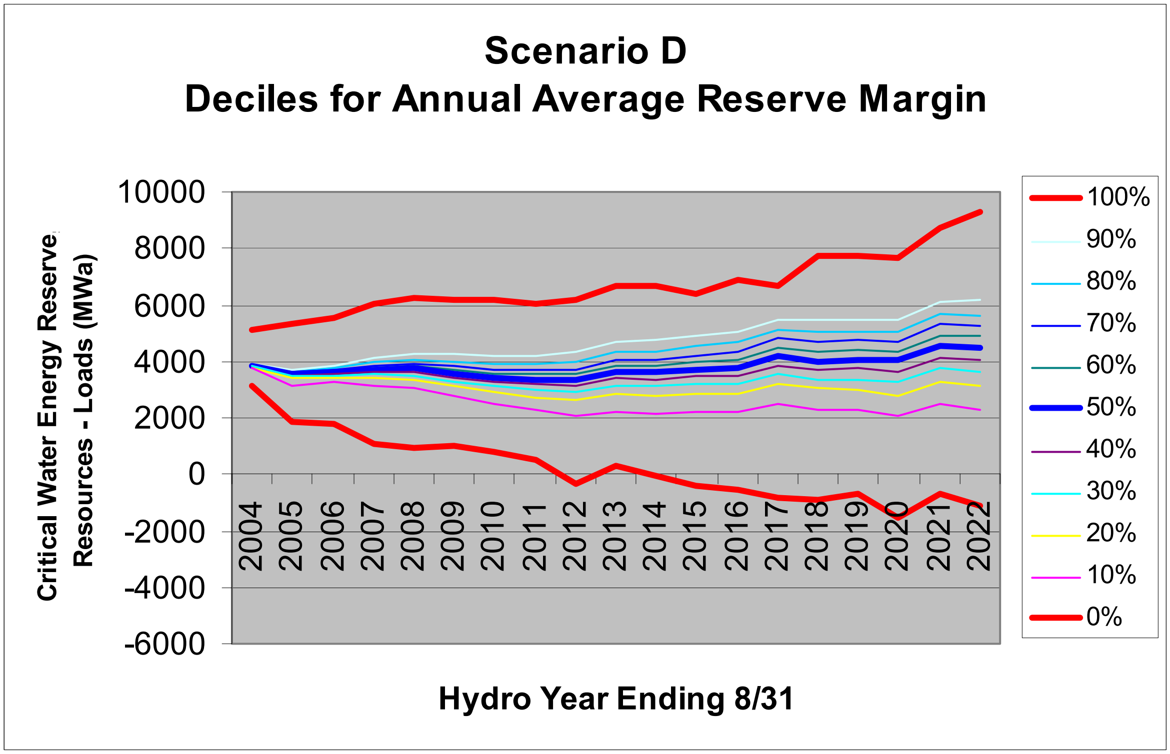



**Figure P-116: Statistical Summary of Reserve Margin, Least-Risk Plan (D)**

Finally, the lower jaw moves into negative energy reserve only in outlying years. From studies that the Council has performed on regional reliability, a deficit of 1000 MWa would still produce a reasonably reliable system as measured by loss of load probability. This graph suggests that economic reliability is more conservative, requiring more total resource, than engineering reliability measures. This stands to reason, because engineering reliability ignores the costs of the plants providing such reliability. In fact, inefficient or costly resources may be supporting the system for significant periods.

Several technical assumptions are material to interpreting these figures. First, IPP energy, totally about 3250 MWa, is included in the reserve margin calculation. Several regional planning organizations, such as the Pacific Northwest Utility Coordinating Council (PNUCC), do not include regional energy not under contract. Second, the energy associated with generation resources is discounted by maintenance but not by forced or unplanned outages. This is consistent with industry practice. Finally, the reserve calculation includes firm regional contracts and sales, according to the BPA White Book, and assumes 11650 MWa for critical water hydrogeneration.

Intuition suggests that lower cost, higher risk plans on the efficient frontier would have lower energy reserves. Working along the efficient frontier through Scenarios C and D (Figure P-118) to Scenario A (Figure P-117), this pattern is evident. All of the plans start out in a similar situation, which existing resource and load dictate. Only after about the year 2010 do the energy reserves differ significantly. The region is in a surplus situation

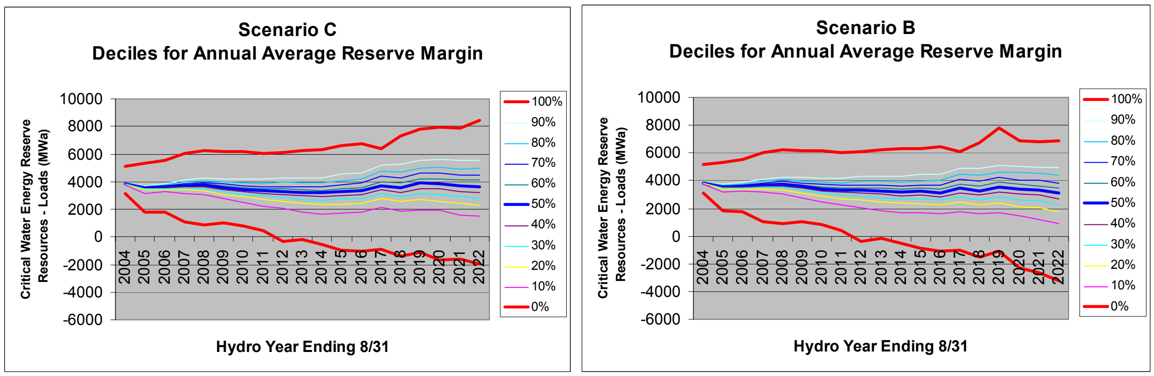



**Figure P-118: Energy Reserve Statistics for Scenarios C and B**

until then, and no resources or other actions – except for small differences in conservation – differentiate the scenarios.

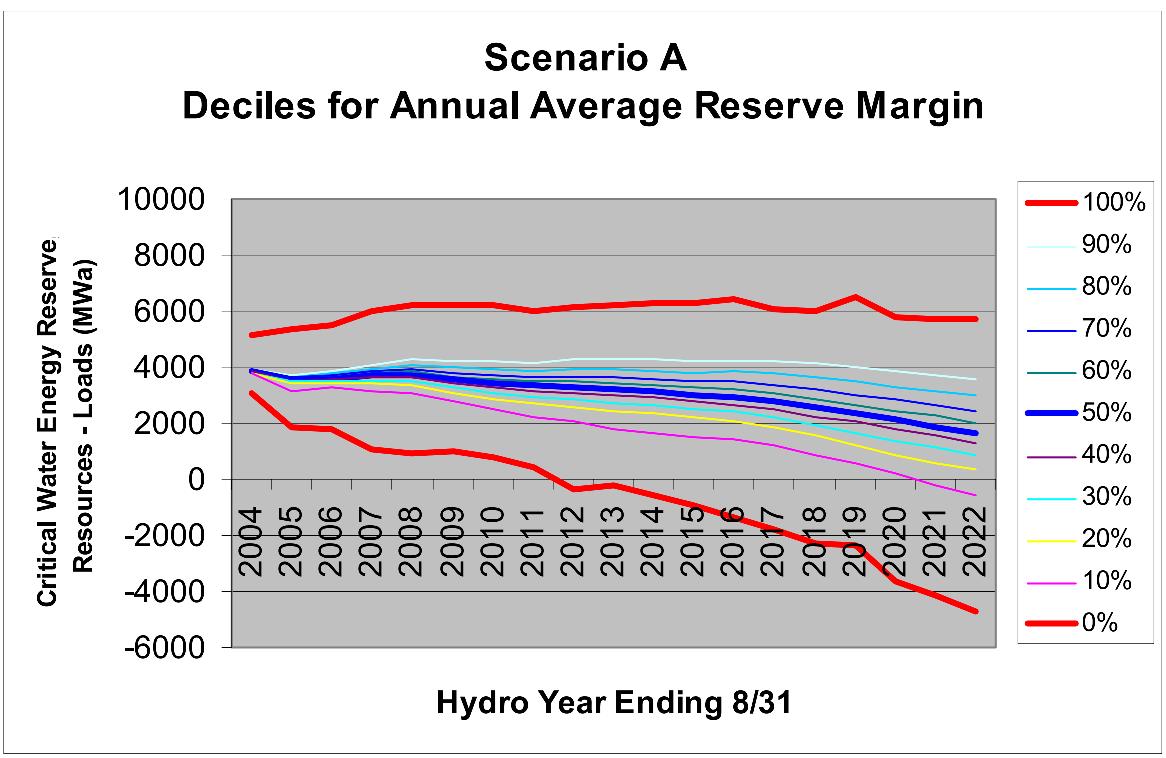



**Figure P-117: Statistical Summary of Reserve Margin, Least-Cost Plan (A)**

The least-cost plan, Scenario A, has a reserve margin that falls roughly 2200MWa between 2010 and the end of the study. In the least-cost plan, only inexpensive conservation enters the plan. It is not evident that Scenario A's energy reserve margin stabilizes during the study.

Loss of Load Probability (LOLP)

For the reasons described in the previous section, it's difficult to make a direct comparison of loss of load probability using the regional model to that from the traditional model. Nevertheless, Council Staff used the GENESYS model to analyze Plans A, B, C, and D using a single, representative future [**36**]. For this future, fuel prices and loads are identical to the benchmark values used in the regional model. Conservation and smelter loads are the average values across futures in the regional model. Power plant construction proceeds without interruption, and all power plants are in service on the earliest feasible date.

The three lower risk plans all produced zero loss of load probability across the years in the study. Only the least cost plan produced nonzero values.

Figure P-119 [**37**] shows the loss of load for the least cost plan in average megawatt-seasons on the vertical axis and the exceedance probability of the horizontal axis. There are five exceedance curves in this figure, corresponding to the study years 2008, 2010, 2013, 2018, and 2023. The horizontal, heavy black line is the Councils threshold for a significant event. The Council considers events smaller than 10 megawatt-seasons too small to be of concern. System operators can probably take some extraordinary measure to deal with such events, short of curtailing loads. The vertical, dashed red line is the Councils threshold for event likelihood. In principle, it is impossible to build a completely reliable system. Therefore, it becomes necessary to define a likelihood below which loss of load events are acceptable.

The Council considers a plan reliable if events do not simultaneously exceed the two thresholds. Referring to Figure P-119, the reliability of the system in a year corresponding to the curves is adequate if the curve does not enter the upper right hand quadrant defined by the two thresholds.

Clearly, the least-cost plan (Plan A in Figure P-103) is adequate by this definition in every year. The maximum loss of load probability associated with least-cost plan occurs in those two years just before an early combined cycle and wind power plant come online and again near the end of the study. Loss of load probability, by the Councils definition, reaches four percent in those two years.

This section on engineering reliability opened with a comment that economic risk assessment appears to be more sensitive than engineering reliability assessment. In this section, studies show that plans – even least-cost plans – that are on the efficient frontier pass engineering reliability planning criteria. This stands to reason because engineering reliability criteria, such as those presented in this section, ignore cost. Engineering criteria use prices to assure that the system operates in a realistic manner, using merit dispatch, but if load is not lost, there is no penalty. Economic risk metrics, on the other hand, will warn planners in advance that the last remaining, most expensive resources in the supply stack are maintaining reliability. Sufficiently high prices and penalties, moreover, will signal any event relevant to engineering reliability. In this sense, then, we conclude that economic risk assessment tend to be more sensitive than engineering reliability assessment.

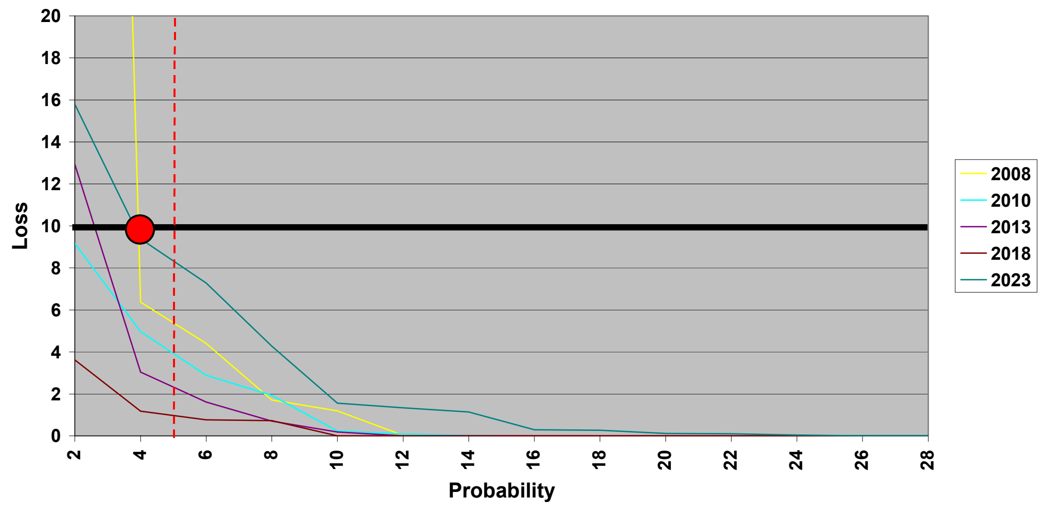



**Figure P-119: LOLP for Least-Cost Plan**

## A Final Risk Consideration

Reviewing the results presented in this chapter, it would be reasonable to choose Plans B, C, or D. Plan A clearly has more risk and cost volatility. While Plan D has lowest risk, Plans B, C and D have comparable performance. All three plans call for substantial amounts of wind, which is absent in Plan A. Plan C adds more CCCT capacity later in the study; Plan D begins the construction of an IGCC coal plant in 2012.

One source of risk not discussed above, however, is the risk of premature commitment. Most planners understand that it would be a blunder to commit to a decision any earlier than necessary. More time brings more information and perhaps additional options. This is the reason why plans typically comprise an *action plan*, focusing on the immediate commitments, and the rest of the plan, which addresses activities later in the study.

The selection of Plan D costs nothing now and reduces premature commitment risk. Specifically, it implicitly calls for reevaluation of alternatives earlier than would Plan B or Plan C. The coal plant and CCCT units have longer lead-time than do the wind units, and the wind units in Plan D arrive earlier and in larger number. By selecting Plan D, the Council has signaled a reevaluation of the Plan no later than 2009, three years before the earliest construction date 2012. Three years are necessary for the siting and licensing process of a IGCC plant. If the IGCC were to be located in a transmission constrained region like Idaho or Montana, which is a strong possibility, transmission studies need to begin immediately. Transmission has an even longer lead-time. If the Council were to choose Plans B or C, instead, no reevaluation probably would be necessary until 2012, and transmission may not be as much of an issue. If the region waited until 2012 and then discovered it needed an IGCC plant, however, the delay could be costly.

## Summary and Conclusions

This section addresses $TailVaR_{90}$ as a risk measure for the region. The section introduced coherence measures of risk and explained their advantages. ($TailVaR_{90}$ as a coherent risk measure.) It explored alternative measures of economic risk and evaluated how representative $TailVaR_{90}$ is with respect to each. It concludes that $TailVaR_{90}$ is representative, in the sense that the other risk measures examined would have produced the same or substantially the same choice of plans for the efficient frontier.

This section also examined the plans on the efficient frontier using cost volatility and engineering reliability planning criteria. Plans on the efficient frontier do not have the least cost volatility, but they do possess moderate cost volatility. Economically inefficient, resource-surplus plans have lower cost volatility. Among the plans on the efficient frontier, cost volatility decreases with plan risk, as measured by $TailVaR_{90}$. Most of the volatility, however, diminishes passing from the least-cost plan (Plan A) to Plan B (Figure P-103). All of the plans on the efficient frontier appear to be reliable with respect to loss-of-load probability (LOLP) and resource-load balance.

Finally, while Plans B, C, and D have similar performance with respect to cost volatility and engineering reliability planning criteria, Plan D permits the Council to minimize premature commitment risk at no cost. For this reason, the Council selected Plan D as its preferred resource plan for the Council's Fifth Power Plan.

# *Sensitivity Studies*

This chapter presents the results of detailed sensitivity analyses. The Council performed over 160 studies to understand how the conclusions of the model depended on assumptions, such as model structure, natural gas price, carbon penalty, the rate of conservation implementation, the feasibility of wind generation, and alternative decision criteria. Valuation studies are a specific kind of sensitivity analysis. The Council performed studies to value conservation, demand response, wind, and the gross value of independent power producers' power plants. Each study requires producing a feasibility space: about 1400 twenty-year plans, each evaluated using 750 futures. In all, this work represents approximately 160 million twenty-year studies of hourly Northwest power-system operation.

The sensitivity studies appearing in this section do not all use the same basecase or model. Because preparing feasibility spaces is time-consuming, typically requiring a day of computer simulation and a comparable amount of time for analysis, this section presents only the last completed studies. This should not be a limitation, however, to understanding the influence or effect in question. The Council performed these sensitivities with several models and varying sets of assumptions. After studying the results from multiple studies, typically a strong and intuitive pattern emerges. This chapter will present those patterns.

The reader should pay *little* attention to the absolute cost and risk values associated with the feasibility spaces, therefore. The base case values will depend on the model logic and assumptions, which may change dramatically from summary to summary. Instead, the reader should pay attention to the *change in location and shape* of the efficient frontier, between the sensitivity case and *its* corresponding base case. Each section below will present these side by side, with the base case illustrated with blue points and the change case illustrated in red points.

In the following, the format of each section will be
- A brief description of the issue
- Description of the workbook modeling
- Results from the efficient frontier
- General observations and conclusions

## High Natural Gas Price

In this sensitivity [**38**], the average natural gas price was $1.50/MMBTU higher than in the base case. The purpose is to understand the implications if the median of the natural gas price distribution were higher than used in the base case.

There is no adjustment to electricity price, including through sensitivity parameters, described in the section beginning on page P-72. The benchmark prices in {{row 53}} are $1.50/MMBTU higher.

Figure P-120 shows the displacement of the efficient frontier due to increased price of natural gas. The base case is in blue (light blue frontier) and the sensitivity case is in red (yellow frontier). Much of this displacement, of course, is due to existing gas-fired resource. The new resources in the plans along the frontier have little influence on total system cost.

What is of interest is the makeup of plans on the efficient frontier. Perhaps not surprising is that wind generation and conservation develop more across the entire efficient frontier, while CCCTs are less popular. More surprising is that coal is not on the efficient frontier in either case, and there remains a substantial amount of CCCT siting and licensing. Despite low coal price and there being no uncertainty associated with coal price, this change in the distribution of probabilities for gas price futures seems to have little effect on the attractiveness of coal-fired generation. That CCCTs remain attractive can be understood from two factors. First, wind generation development is capped, and additional capacity of some sort is required. Second, new gas-fired generation is more efficient than existing gas-fired generation. Consequently, the newer units can economically displace older gas-fired units.

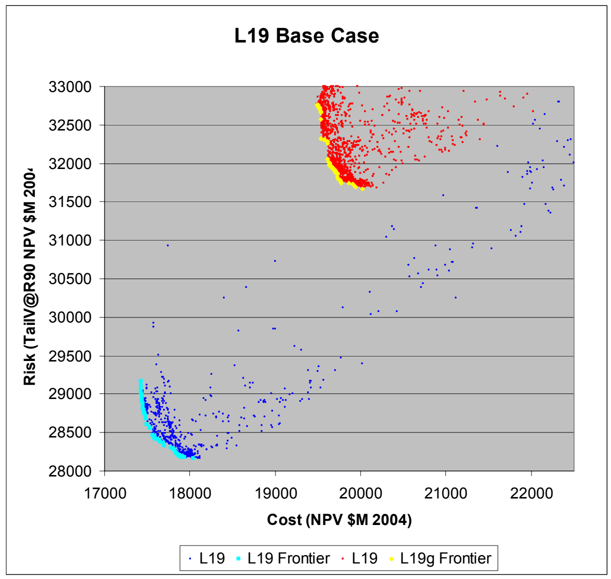



**Figure P-120: High Natural Gas Price**

## Reduced Electricity Price Volatility

Electricity price volatility does not affect the value of all plants or plans equally. Non-dispatchable plants like wind and conservation, for example, are unaffected by such volatility. Only the average price of electricity determines their hourly value. On the other hand, volatility is a major determinant of the value of high-heat rate combustion turbines, such as SCCTs, and of demand response. Volatility also will increase the value of reserve margin strategies. Volatility can affect decision criteria differently. Thus, it is important to understand the influence of volatility assumptions.

In one study [**39**], Council Staff cut in half the four parameters that control the jump size and principal factors for the independent term of electricity price:

Principle Factor constant offset (R94): (-0.5, 0.0, 0.5) ← (-1.0, 0.0, 1.0) triangular distribution
Principle Factor growth (R96): (-0.58, -0.33, 0.42) ← (-0.83, -0.33, 1.17) triangular distribution
Jump 1 Size (S99): (0.1.25) ← (0,2.50) uniform
Jump 2 Size (S100): (0.1.25) ← (0,2.50) uniform

As one might suspect, the average cost and risk declined with reduced electricity price volatility (Figure P-121). With this change, the premium for conservation disappeared, except at the most risk-averse end of the efficient frontier. The CCCTs are not developed. Contrary to the situation described at the opening of this section, there is *more* development of SCCTs. The lower probability of futures with high electricity prices would tend to make the fully allocated cost of such power less expensive. Wind develops somewhat less extensively across the efficient frontier, perhaps for the same reason as for other capital-intensive resources.

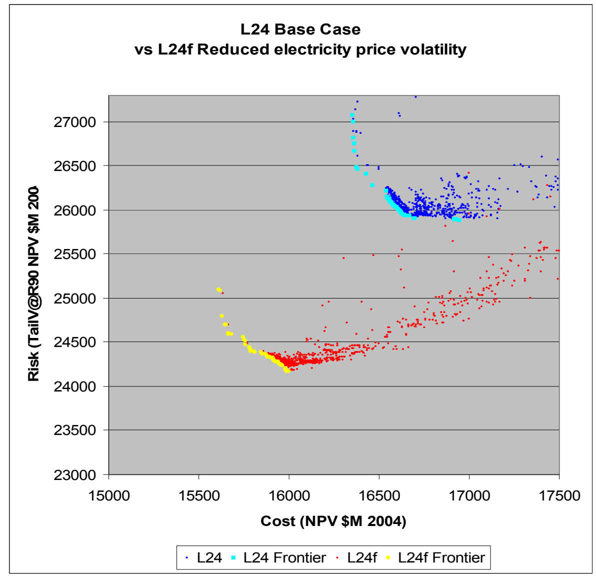



**Figure P-121: Reduced Electricity Price Volatility**

## $CO_2$ Policy

Because of the prominence of debate over climate change, its possible causes, and its possible effects, the Council performed numerous analyses with alternative assumptions regarding the magnitude and likelihood of a $CO_2$ tax. (See also the discussion of $CO_2$ uncertainty, above.) Some decision makers may do not share the view of $CO_2$ tax uncertainty adopted by the Council. These studies can perhaps help inform those decision makers about the credibility of regional model results.

### No $CO_2$ Tax or Incentives for Wind

One view of the future might be that, scientists will determines climate change is unrelated to manmade activities. Moreover, clean fossil fuels will become cheap and abundant. There is no chance of any $CO_2$ tax in this world and renewable energy has no value. Consequently, there is no chance for continuing the PTC, and green tag value falls to zero.

Note that base case modeling for $CO_2$ tax, PTC, and green tags already allows for *futures* such as this. This sensitivity study, however, posits that there is ***no possibility*** of positive values for these uncertainties.

Four separate studies examined the consequences of this set of assumptions. The latest [**40**] found new wind generation constructed in less quantity and much later, if at all, along the efficient frontier. Instead, a modest amount (400MW) of coal-fired capacity can begin construction around 2013 in about half the plans, those nearer the least-risk plan. The plans also have greater incentive for and more extensive deployment of lost-opportunity conservation. There is slightly less CCCT development at the least-cost end of the efficient frontier and slightly more development at the other end.

Many assume that the possibility of a CO2 tax is coal generation's biggest risk. This study shows that eliminating CO2 tax alone does not make coal a leading candidate for new capacity, even assuming low and stable fuel cost. The section "Conventional Coal," below, elaborates on the regional model's study results for that technology.

## Higher CO2 Tax

For a study that incorporates higher levels of $CO_2$ tax [**41**], the Council chose one of the tax scenarios that appear in an MIT analysis of the proposed 2003 McCain-Lieberman Act.[42] The study implements the McCain-Lieberman schedule for CO2 tax (MIT Study, Table 4, page 17, Scenario 5), which is $25/ton (2010), $32/ton CO2 (2015), $40/ton CO2 (2020), all in 1997$. These levels are converted to 2004$ by annual inflation of 2.5 percent and are converted to piecewise linear function of time. The resulting schedule appears in Figure P-122. This high level of tax is deterministic and is present in all futures with the same fixed schedule. (The regional model workbook implements the tax by pasting the values in this figure into row {{74}}, the final value for the CO2 tax future.)

The feasibility space, illustrated in Figure P-123, shifts significantly up and to the right. The additional expected system cost associated with this sensitivity is about $9 billion (NPV 2004$). Discretionary conservation takes a big step forward in this sensitivity, increasing both the recommended premium for development and the amount delivered. CCCTs and wind develop extensively, even in the least-cost plans. The incentive for new CCCT capacity is the displacement of older, less efficient units. Not too surprising, coal-fired generation is nowhere near the efficient frontier.

| Inflation annual rate | | | Conversion to 2004$ |
|---|---|---|---|
| 2.5% | | | 1.188686 |
| Calendar Year | Period | 1997$ | 2004$ |
| 2004 | 2 | 1.00 | 1.19 |
| 2004 | 3 | 2.00 | 2.38 |
| 2004 | 4 | 3.00 | 3.57 |
| 2004 | 5 | 4.00 | 4.75 |
| 2005 | 6 | 5.00 | 5.94 |
| 2005 | 7 | 6.00 | 7.13 |
| 2005 | 8 | 7.00 | 8.32 |
| 2005 | 9 | 8.00 | 9.51 |
| 2006 | 10 | 9.00 | 10.70 |
| 2006 | 11 | 10.00 | 11.89 |
| 2006 | 12 | 11.00 | 13.08 |
| 2006 | 13 | 12.00 | 14.26 |
| 2007 | 14 | 13.00 | 15.45 |
| 2007 | 15 | 14.00 | 16.64 |
| 2007 | 16 | 15.00 | 17.83 |
| 2007 | 17 | 16.00 | 19.02 |
| 2008 | 18 | 17.00 | 20.21 |
| 2008 | 19 | 18.00 | 21.40 |
| 2008 | 20 | 19.00 | 22.59 |
| 2008 | 21 | 20.00 | 23.77 |
| 2009 | 22 | 21.00 | 24.96 |
| 2009 | 23 | 22.00 | 26.15 |
| 2009 | 24 | 23.00 | 27.34 |
| 2009 | 25 | 24.00 | 28.53 |
| 2010 | 26 | 25.00 | 29.72 |
| 2010 | 27 | 25.35 | 30.13 |
| 2010 | 28 | 25.70 | 30.55 |
| 2010 | 29 | 26.05 | 30.97 |
| 2011 | 30 | 26.40 | 31.38 |
| 2011 | 31 | 26.75 | 31.80 |
| 2011 | 32 | 27.10 | 32.21 |
| 2011 | 33 | 27.45 | 32.63 |
| 2012 | 34 | 27.80 | 33.05 |
| 2012 | 35 | 28.15 | 33.46 |
| 2012 | 36 | 28.50 | 33.88 |
| 2012 | 37 | 28.85 | 34.29 |
| 2013 | 38 | 29.20 | 34.71 |
| 2013 | 39 | 29.55 | 35.13 |
| 2013 | 40 | 29.90 | 35.54 |
| 2013 | 41 | 30.25 | 35.96 |
| 2014 | 42 | 30.60 | 36.37 |
| 2014 | 43 | 30.95 | 36.79 |
| 2014 | 44 | 31.30 | 37.21 |
| 2014 | 45 | 31.65 | 37.62 |
| 2015 | 46 | 32.00 | 38.04 |
| 2015 | 47 | 32.40 | 38.51 |
| 2015 | 48 | 32.80 | 38.99 |
| 2015 | 49 | 33.20 | 39.46 |
| 2016 | 50 | 33.60 | 39.94 |
| 2016 | 51 | 34.00 | 40.42 |
| 2016 | 52 | 34.40 | 40.89 |
| 2016 | 53 | 34.80 | 41.37 |
| 2017 | 54 | 35.20 | 41.84 |
| 2017 | 55 | 35.60 | 42.32 |
| 2017 | 56 | 36.00 | 42.79 |
| 2017 | 57 | 36.40 | 43.27 |
| 2018 | 58 | 36.80 | 43.74 |
| 2018 | 59 | 37.20 | 44.22 |
| 2018 | 60 | 37.60 | 44.69 |
| 2018 | 61 | 38.00 | 45.17 |
| 2019 | 62 | 38.40 | 45.65 |
| 2019 | 63 | 38.80 | 46.12 |
| 2019 | 64 | 39.20 | 46.60 |
| 2019 | 65 | 39.60 | 47.07 |
| 2020 | 66 | 40.00 | 47.55 |
| 2020 | 67 | 40.40 | 48.02 |
| 2020 | 68 | 40.80 | 48.50 |
| 2020 | 69 | 41.20 | 48.97 |

**Figure P-122: Adapted CO2 Schedule**

[42] Paltsev, S., J.M. Reilly, H.D. Jacoby, A.D. Ellerman & K.H. Tay, ***Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal***, MIT Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology, June 2003 http://web.mit.edu/globalchange/www/ (Link to file server)

This study is the latest of three performed using different base case assumptions. All studies resulted in roughly the same outcomes.

## CO2 Tax of Varying Levels of Probability

As mentioned in the Uncertainty chapter, some carbon tax is present in about two-thirds of futures. With no CO2 tax and few incentives for wind, coal-fired generation begins to make an appearance on the efficient frontier. (See the discussion on page P-135.") In early studies [**42**], CO2 tax was not tiered as it is in the Draft and Final Plans, and the probability of a CO2 tax was higher. In an attempt to threshold the conditions that favor alternative plans, various modeling studies [**43**] examined the effect of reduced probability of $CO_2$ tax and increased natural gas price. These studies shaped the representation for CO2 tax used in the final Plan.

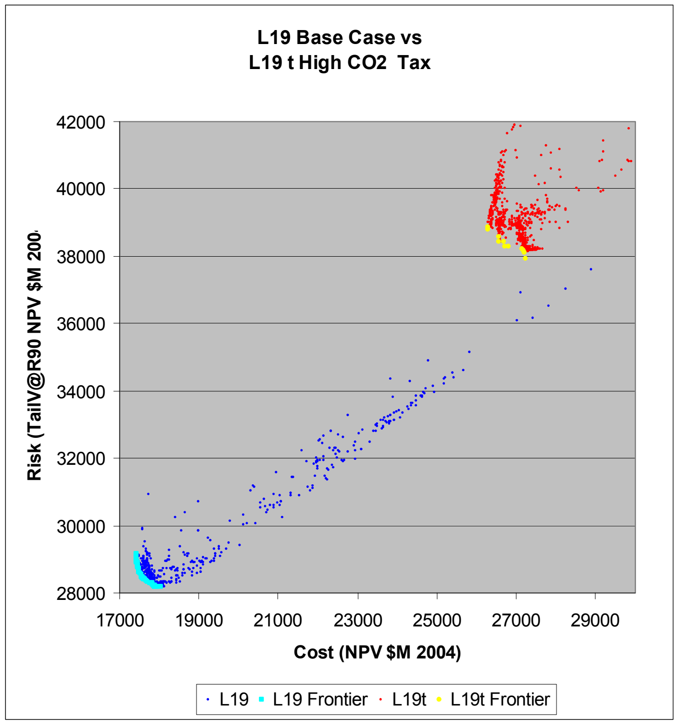



**Figure P-123: Feasibility Space for High CO2 Tax**

Examining the plans on the efficient frontier of the study least favorable to wind generation and most favorable to coal-fired generation, wind still demonstrated a relative advantage. Even with only 25 percent probability of a CO2 tax by the end of the study and an increase of $1.50/MMBTU in natural gas prices, no coal plants appeared.

These studies convinced the Council that in the kind of risk analysis the regional model performs the "tail events" can and often are more important than expected value events. The models does not choose Coal in plans at the least-cost end of the risk-cost trade-off curve, because relying on the market and not building resources is least cost. The models does not choose Coal in plans at the least-risk end of the curve, often because the futures where $CO_2$ tax does appear and planning flexibility is important hurt the performance of such plans.

To model these studies, the uniform distribution in the assumption cell {{R72}}, which controls in which period a CO2 tax of any size occurs, has larger range. Extending the upper value of the uniform distribution to 20 from six effectively reduces the chance any tax will start before the end of the study. (See page P-88 ff for a description of how the model uses this parameter.)

## Independent Power Producers

In studies performed before release of the Draft Plan, the regional model considered Independent Power Producer (IPP) generation part of the region. During the vetting process, however, the Council realized that this was not consistent with how previous Council plans have defined the region. Specifically, the Council has taken the "region" to be the *ratepayers* in the area specified by the Act. It is also not consistent with how other regional utility planning organization, such as the Pacific Northwest Utility Coordinating Council (PNUCC) account of IPP plants.

Equating the region to its ratepayers is key to how the regional model performs its economic evaluation. The fully allocated costs of power plans belonging to regional utilities eventually pass to regional ratepayers. With public utilities and co-ops, the flow of plant expenses and profits back to ratepayers is relatively direct and evident. For privately held utilities, the flow may be less obvious to some observers. Assuming perfect regulation, the shareholders of private utilities receive only the return of and the return on capital investment in plants, called the "ratebase." These returns occur over time, through the utility rates. This means that revenues *unrelated* to ratebase, the profits and losses from power plant operation, flow back to *ratepayers*, not to shareholders. Thus, the economic situation is just as it would be for a municipal utility.[43]

With IPP generators, however, the situation is different. Profits and losses from power generation of merchant plants flow to shareholders, who are *not* generally ratepayers of the region. The ratepayers effectively pay prevailing market prices for IPP power. (Perhaps forward contracts markets or ancillary services markets are more appropriate than wholesale firm energy markets in a given situation, but the principle is the same.)

With that clarification, the Council changed how the regional model captures the role of IPP plants. In the Draft and Final Plan, IPP plants contribute only to the energy balance in the region. The model ignores IPP costs and profits.

This does not mean, however, that the IPP units have no influence in the results. Because the model constrains regional imports and exports, the model changes electricity prices as necessary to balance supply and demand. (See "The Market and Import/Export Constraints" and, in particular, the subsection "RRP Algorithm" in Appendix L for an explanation of this process.) To the extent that there are additional sources in the region to balance requirements, therefore, the likelihood of higher electric market prices diminishes. The lower expected market prices, in turn, flow through to the region. Regional utilities will buy and sell into the market to balance their respective load, and the additional IPP generation will extend the depth of supply in that market. The Council believes this approach more accurately models the role IPPs serve in the region.

[43] There are, of course, financing, governance, and other differences, but the model tries to deal with those through the calculation of real levelized costs (see Appendix L). The discussion here is only about whether the construction and operating revenues pass to the ratepayer.

This situation comports with information provided by the IPP industry and with publicly available data on IPP plant dispatch. Much of the information about the role of IPPs in the region appears in Chapter 2 of the Plan, as well as in the Overview of the Plan. In summary, about 3000 MW of IPP capacity remained uncommitted as of December 2004, when the Council adopted the Final Plan. Spot sales into the market remained vigorous, nevertheless, with plants averaging about 50 percent capacity factor over the previous year.

How does the workbook model represent IPP operations? Appendix L has several pages of description, under the chapter "Resource Implementation and Data." The reader will find there both the model's data and formulas.

This section describes two studies the Council performed to better understand the role of the IPPs in the region. The first looks at the value of IPPs to the region. The second examines the effect if out-of-region purchasers contracted for all of the IPP capacity.

## IPP Value

A study [**44**] attempted to estimate how much the IPP generation would be worth to the region, assuming all of the costs and benefits flowed through to regional ratepayers. This might arise, for example, if regional utilities contracted for all the output of the IPP plants.

The study, however, suffers from a serious difficulty. The approach is simply to include the operating costs and benefits of IPP plants, much as in early study work. This is acceptable for existing regional plants, because the construction costs are embedded and do not change from plan to plan or from future to future. For the region, however, the cost of acquiring the IPP plants is not "sunk;" it is not embedded. In fact, depending on the price that utilities would pay to acquire the output of the IPP plants, any benefit will shift between regional ratepayers and IPP shareholders. If the price were high enough, the region might not see any benefit, and it might even see a net disadvantage.

The problem does not go away if the study simply chooses an arbitrary allocation of benefit. The modeling issue is more delicate than that. At some price, which we have no easy way to determine beforehand, plans including IPP purchases or contracts will not appear on the efficient frontier of the feasibility space. Substitutes for risk mitigation will become competitive. Moreover, because the IPP plants are not homogeneous – Centralia coal plant is among them, for example – plants will not appear on the efficient frontier in aggregate. The problem would then become one of determining a threshold acquisition price for each resource. That threshold price, in turn, depends on which other IPP resources appear on the efficient frontier. Of course, nothing assures us that the price the region might be willing to pay for a plant's output would be acceptable to the current owner.

There are, of course, many other difficulties. Acquiring IPP output can adversely affect utility financing, for example. Chapter 2 of the Plan mentions some of the more prominent reasons why utilities might not choose to contract for IPP output.

With these caveats, this sensitivity study implicitly assumes IPP owners give the plants to the region for free. There is no acquisition cost. This sets a (rather unrealistic) cap on the potential value of acquiring the plants for the region. Figure P-124 illustrates the reduction in cost (about $4 billion) and risk.

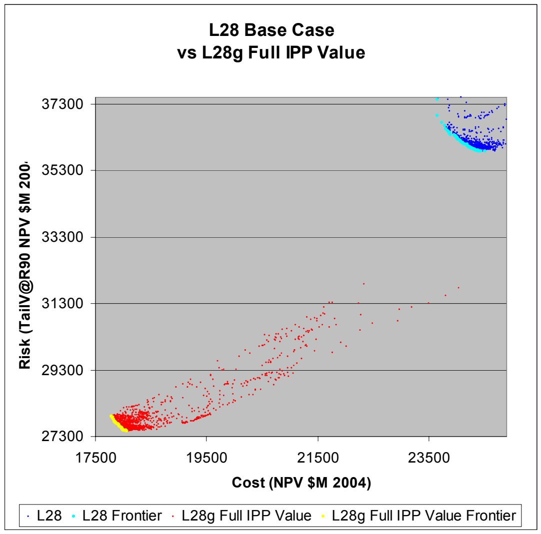



**Figure P-124: Acquiring the Full Value of IPP Plants**

Purchasing the output of the IPP plants pushes off most of the schedules for new resources, in including conservation and wind. Because of their reliance on fossil fuels and natural gas in particular, however, IPP units cut the schedule of wind by half, but some wind remains on the frontier. In the least-risk case, 2500MW of wind appears before the end of the study.

In the workbook, capturing the cost and benefit of the IPPs amounts to reversing the NPV cost adjustments described in Appendix L. Appendix L uses the example of the on-peak values for the surrogate plant "PNW West NG 3 006" which appear in row {429}. From the Appendix L discussion of valuation costing and of the thermal dispatch UDF, the value is the negative cost appearing in this row. The formula in cell {CV429} discounts these values to the first period:

=0.434512325830654*8760/8064*NPV(0.00985340654896882,$R429:$CS429)*
(1+0.00985340654896882)

The factor of roughly 0.4345 discounts the value of the plant, because about 43.45 percent of the plant belongs to a utility in the region and the rest of the plant (56.55 percent) is IPP. For the sensitivity study, this leading coefficient becomes 1.0, as do those for any plant that is partially or completely IPP.

## Contracts for Sale of IPP Energy Outside of the Region

Participants in the public process of reviewing the regional resource plan asked, “What would happen if the output of the IPP plants were contracted outside the region?” The concern is that the region might suddenly find itself substantially short of resources. If that situation were possible, the region might need to acquire additional resources as protection against that contingency.

The initial approach to modeling this situation was simply adding contract exports, along with corresponding counter-scheduling adjustments to import/export constraints (see "Contracts" in Appendix L). This creates a heavier load for region, which the IPPs should incur. There must be an addition adjustment, however, to the economics. Increasing the load alone increases the *economic* obligation of the *region*. That is, the region sees an increase in the load it must serve. This is incorrect, however, as the IPPs are incurring the economic obligation, not the region. Thus to correctly model the situation, the energy out of the region must be increased, but the load used for economic value (or cost) of existing contracts to the region should remain *as in the base case*. With this representation, any effect for the region is due to electricity market price increases due to IPPs no longer contributing to the market.

Figure P-125 shows the results of this study [**45**]. Effectively, the sensitivity case and base case feasibility spaces are lying on top of one another. Within the repeatability of this tool, there is no discernable difference. The plans along the efficient frontier are essentially the same, as well.

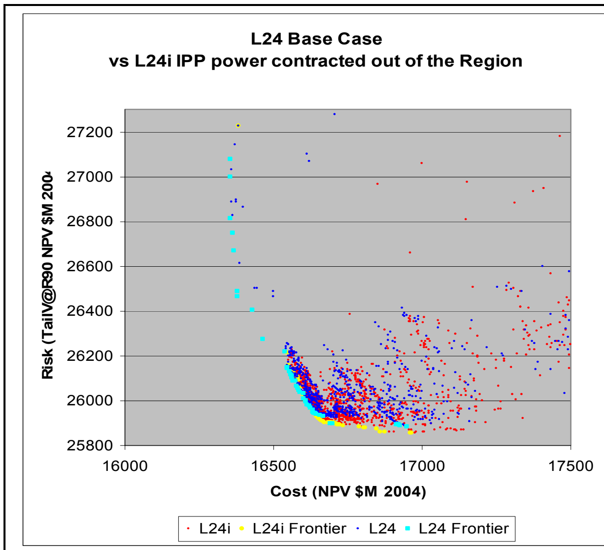



**Figure P-125: IPP Energy Contracted Out-of-Region**

Why would there be so little change? At least market prices should rise, as mentioned above, increasing the cost to the region. In fact, what happens is that the model counter schedules contracts. The final dispatch of IPP units does not depend on the contract terms or initial contract obligations, but only on the IPP plant economics relative to the other plants in the region, i.e., a plant's place in the system merit order. The market price for electricity, in turn, depends primarily on the dispatch of the plants in the region. (See Appendix L for a discussion of economic contract counter-scheduling.) Therefore, market prices are unaffected by contracts. Indeed, this is the reason why many simulation models, such as Aurora, can and do ignore contracts.[44]

[44] A handful of models, such as the Henwood's PROSYM® model, do model contracts because they need to capture pre-dispatch commitment costs due to reliability provisions in transmission and capacity contracts, or because their results will be used for production costing, where financial arrangements are important.

Contracts do make a large difference to the parties of the contract, of course. The difference is financial, however, and Appendix L shows it is in the economic self-interest of the supplier to re-dispatch units whenever physical constraints are binding or plant economics are out of merit order.

The workbook modeling for this sensitivity study is involved. First, contract sales, both on- and off-peak, increase by the combined seasonal output of the IPP plants. The original level of sales, however, remains in the workbook for the economic costing calculation. The net cost of contracts will be the net position times the prevailing market price. (The study assumes contract cost of energy is fixed and embedded. This would be the case for a forward contract. The *net* value of contracts is the difference between this fixed cost and the value of the energy.) The seasonal IPP capacity is in Figure P-126.

| | Fall | Winter | Spring | Summer |
|---|---|---|---|---|
| IPP cap | 3259 | 3469 | 2547 | 2939 |

source: IPPs Removed.xls

**Figure P-126: Seasonal Distribution of IPP Capacity**

Second, the seasonal capacities reduce the import values for contracts. The original values remain, however, to permit the cost calculations described above. Figure P-127 illustrates the original and adjusted values for contracts (MWa) on- and off-peak. The on-peak values appear in rows {{83 and 84}} and the off-peak are in rows {{87 and 88}}. The differences between the original and adjusted values are the numbers in Figure P-126. (The difference cycles among the seasonal values throughout the study.) The on-peak energy values are negative, representing net sales out of the region. The original off-peak values are positive, representing net imports, and the adjusted off-peak values are negative, representing net sales.

Figure P-127 also shows the on-peak energy (MWh) and cost ($M 2004) calculations in rows {{367 and 368}}, respectively. The energy calculation uses the adjusted values; the costs use the original. In the formula for cell {{U368}},

= -1152*U83*U204/1000000

the reference to {{U204}} is the on-peak price for energy, and 1152 is the number of on-peak hours in the hydro season. (Appendix L provides a more complete description of this formula and conventions.)

U368 = = -1152*U83*U204/1000000

| | Q | R | S | T | U |
|---|---|---|---|---|---|
| 82 | | | | | |
| 83 | Original On-Peak Contracts | -996.63 | -205.46 | -657.54 | -1147.22 |
| 84 | Adjusted On-Peak Contracts | -4,255.74 | -3,674.89 | -3,204.04 | -4,086.42 |
| 85 | | | | | |
| 86 | | | | | |
| 87 | Original Off-Peak Contracts | 247.50 | 759.93 | 372.54 | 309.84 |
| 88 | Adjusted Off-Peak Contracts | -3,011.61 | -2,709.50 | -2,173.96 | -2,629.36 |
| 366 | | | | | |
| 367 | Fixed Energy ID: Reg Contracts 8 SubPer_003 | -4902614.1 | -4233478.4 | -3691053.4 | -4707557.2 |
| 368 | Cost ($M) | 54.3 | 8.4 | 32.0 | 42.8 |

**Figure P-127: Contract Energy and Value**

The formulas for energy balance and for total study cost point to rows {{367 and 368}}, just as before.

## Reduced Discretionary Conservation

Many questions about the representation and assumptions regarding conservation arose during the studies that led up to the Final Plan. These questions included

- How are decisions about conservation programs made?
- How can the model capture program diversity with a simple supply curve? It is not economic to develop only the least expensive conservation programs, as the supply curve approach assumes. Typically, a utility or customer implements a variety of programs when an opportunity arises to do so. Instead, these programs have a mix of different cost-effectiveness profiles.
- How should the model represent the fact that not all of the energy efficiency programs are mature and that they will mature at different times?
- How does the efficient frontier change as a function of the premium paid for conservation over the "myopic" cost-effectiveness standard?
- Is there value in sustained orderly development, and if so, what is that value?
- To what extend does the rate of deployment affect the cost of a measure?
- What is a reasonable rate of deployment for discretionary conservation, where large amounts of discretionary conservation are cost-effective?

Circumstances forbid sharing all of these studies. The last study, however, is especially prominent. The Council incorporated the results of this study into the base case.

By definition, the region can pursue discretionary conservation at any time. The Council has estimated the amount of such conservation exists in the region, and much of it is cost effective today. In early studies, the regional model controlled the rate of deployment, and the model would choose thousands of MWa of this conservation in the first periods of the study. This is unrealistic behavior for several reasons; not least among them being the limited resources utilities have to pursue conservation.

Chapters 3 and 7 of the Final Plan describe the issues that the Council faced in deciding how rapidly the model could pursue discretionary conservation. Ultimately, this is an educated guess. This section presents some of the quantitative information the Council used to arrive at its conclusions.

The associated studies [**46**] examined three rates of discretionary conservation development: 10 MWa, 20 MWa, and 30MWa per quarter. The Council began examining the effect of these levels over six months before issuing the Draft Plan and checked the results again with the model used to prepare the Final Plan. The results here are from the Final Plan studies. By the time the Council had released the Draft Plan, however, the base case adopted the 30MWa per quarter rate.

Figure P-128 shows how the feasibility space changes as the rate of acquisition moved to 20 MWa per quarter (L28b "Mildly Restricted Conservation") and to 10 MWa per quarter (L28c "Least Conservation"), from 30MWa per quarter. The policy of pursuing 30MWa per quarter appears to facilitate plans that are both less risky *and* less costly.

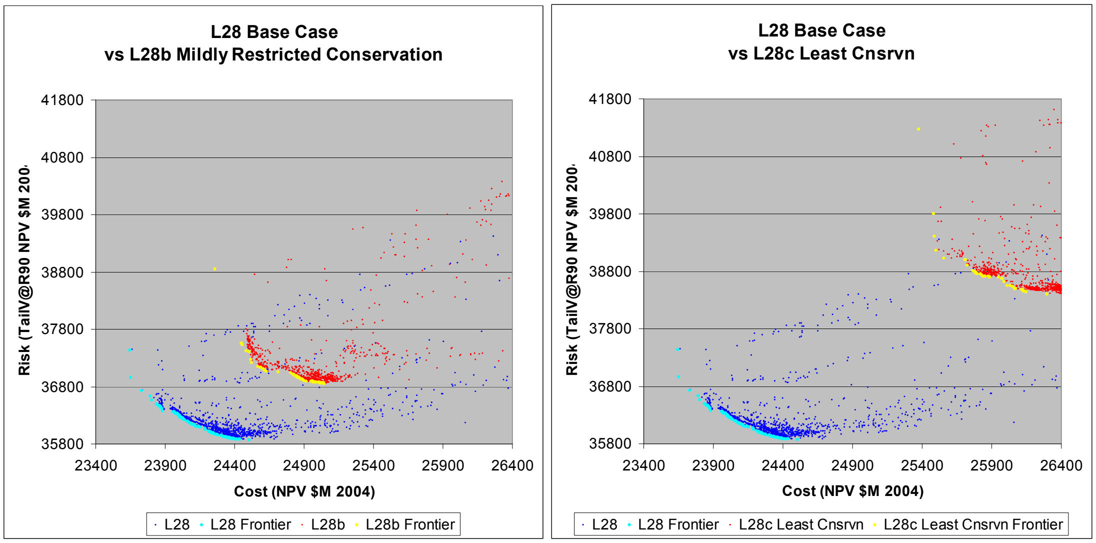



**Figure P-128: Discretionary Conservation Ramp Rate Sensitivity Cases**

To implement this sensitivity in the workbook, the study modified a supply curve modeling parameter. The cell {{J386}} controls the quarterly ramp rate. Figure P-129 shows the set up for the 20MWa per quarter case. A description of how the model represents discretionary conservation with a supply curve is in Appendix L.

| | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|
| 381 | | | | | | | | |
| 382 | DHF(0=Dis | Fixed Ener | Fixed Cost | Fuel Set (ID | Heatrate (E | Planning Flexibility ID ( | Capacity ID (II | Cap_De |
| 383 | 3 | One | (none) | (none) | 0 | Conservation Annual_ | Consv New C | 0,3000,5 |
| 384 | | | | | | | | |
| 385 | | CurveType | Treatment | Upper Pric | Lower Pric | Max Ramp | Init Inc En | Init Curr |
| 386 | | 0 | 1 | 600 | 0 | 20 | 0 | |
| 387 | | | | | | | | |
| 388 | | | | | | | | |

**Figure P-129: Supply Curve Ramp Rate Specification**

## Value of Demand Response

Like the situation for discretionary conservation, early studies suggested that the regional model would take unrealistically large amounts of demand response immediately, given the assumptions in the model. The Council therefore chose to constraint demand response to levels of development it deemed reasonable. Because constraining demand response to these levels essentially fixed deployment of demand response at these levels, the Council eventually decided to fix the demand response-deployment pattern. Using a fixed pattern saves time by relieving the regional model's plan optimizer from examining plans known to be subordinate.

One issue that interested Council Staff, however, was the value of demand response. In the discussion of IPP valuation, above, simply adding the IPP energy value and variable costs to the region's budget did not permit the Council from accurately capturing the value of the IPPs to the region. The reason is that that approach ignores IPP acquisition cost to the region. With demand response, however, the model includes an acquisition cost. Because the Council fixes the demand response-deployment pattern, the study finesses the question of whether a given acquisition cost would affect the deployment decision.

Demand response appears in regional studies as a simple, dispatchable resource. It has low capital cost, and a fuel/dispatch cost corresponding to the payment for which the Council assumed loads might voluntarily remove themselves. The model represents demand response as a combustion turbine with a fixed $150/MWh dispatch cost. The capital costs, however, are low: about $2.26 per kw-year real levelized [**47**]. (See Appendix L.) The Council has an Action Item in the Final Plan to study and refine its cost and availability information about demand response potential in the region. Eventually, modeling will mature into a supply curve approach that reflects the short- and long-term diversity of costs among options.

One study [**48**] of demand response evaluated the impact of removing demand response entirely from the study. The change in feasibility space suggests that, in contrast with many other resources, demand response retains its value at the least-cost end of the efficient frontier. (See Figure P-130.)

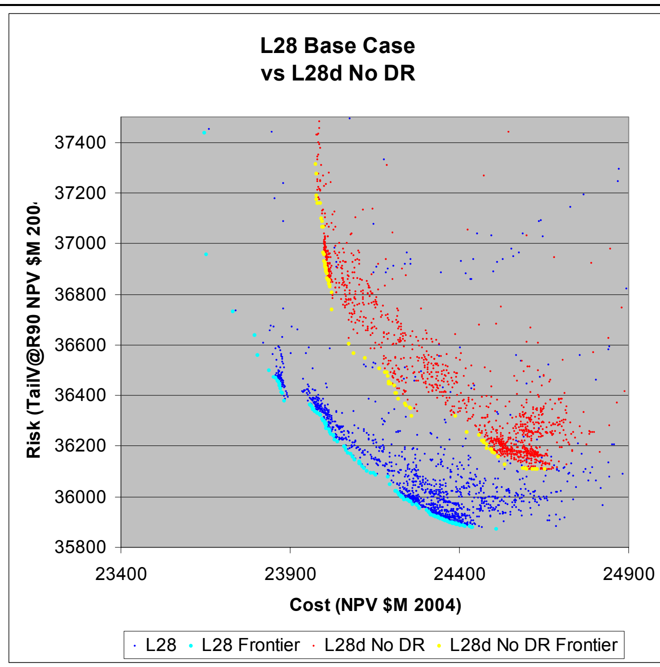



**Figure P-130: Removing Demand Response from the Base Case**

Most resources provide little value at the least-cost end of the efficient frontier because building new plant is no better than relying on the market. (Recall from the discussion for electricity price uncertainty that electricity market price is the same as the fully allocated cost of power plants in equilibrium. Appendix L, in the chapter on "General Paradoxes," and Chapter 6 elaborate on this principle.) If the region plans to build fewer resources, however, electricity prices become more volatile. This is precisely when demand response becomes more valuable.

We can refine the evaluation of the DR value by comparing this sensitivity case against one where the study holds constant the level of demand response across all years. For the purposes of valuing demand response, the base case model is poor because the amount of demand response is increasing over time. In a study [**49**] where demand response is fixed at 500MW, the reader will find a similar pattern as before. Figure P-131 plots the horizontal shift in the efficient frontier as a function of the risk level [**50**]. Again, at the least-cost end (right end of graph) the value of demand response increases. Over most levels of risk, the benefit is between $150M NPV and $200M NPV (2004$). This corresponds to $300 to $400 per kilowatt of benefit, net of program costs. The data is rather noisy at this level of resolution, so a fit polynomial in Figure P-131 reinforces the pattern.

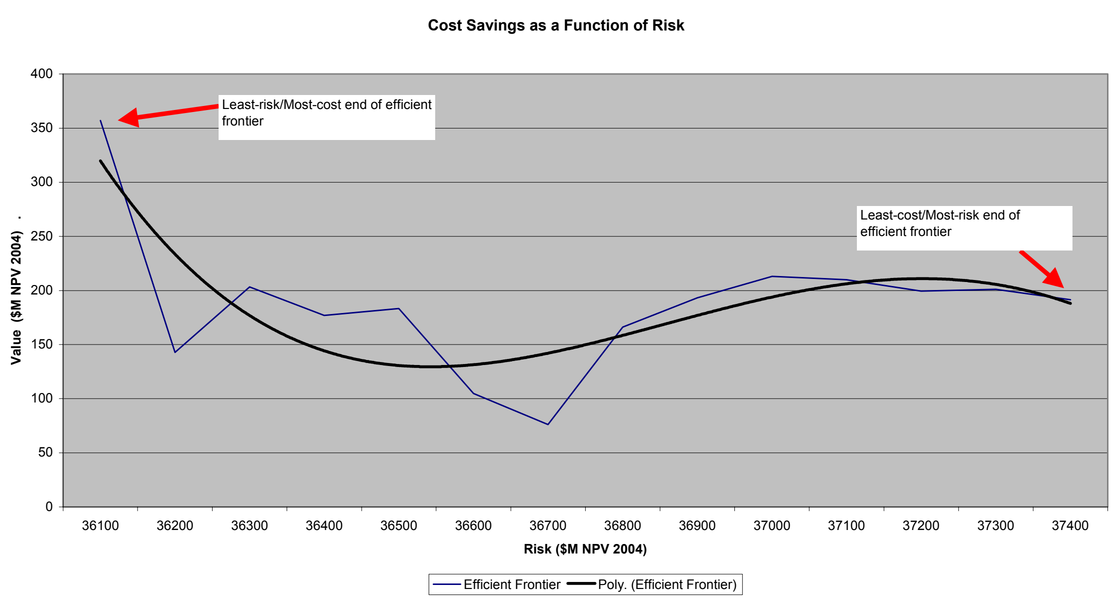



**Figure P-131: Cost Savings as a Function of Risk Level (500MW DR Case)**

Creating the workbook models to perform these studies was simple. As described in Appendix L, Crystal Ball decision cells determine the capacity for new resource candidates. The model considers demand response is a new resource, and the decision cells appear on row {{7}}, labeled "PRD" for *price responsive demand*. Figure P-132 shows the situation for the base case. In the base case, demand response increases over time, and the values in the decision cells indicate the cumulative number of MW of capacity for the new resource option.

In the base case and in the sensitivity cases, the model removes control of the decision cells for demand response from Crystal Ball. For this reason, the cells do not have the yellow background that other decision cells have.

PlnCap_0 = 0

| | N | R | S | AH | AI | AJ | AP | AQ | AR | AX | AY | AZ | BF | BG | BH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Sep-04 | Dec-0 | Sep-08 | Dec-08 | Mar-0 | Sep-10 | Dec-10 | Mar-1 | Sep-12 | Dec-12 | Mar-1 | Sep-14 | Dec-14 | Mar- |
| 2 | Capacity Data ID | | | | | | | | | | | | | | |
| 4 | CCCT Capacity | 0.00 | | | 0.00 | | | 610.00 | | | 610.00 | | | 610.00 | |
| 5 | SCCT Capacity | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 6 | Coal Capacity | 0.00 | | | 0.00 | | | 400.00 | | | 400.00 | | | 400.00 | |
| 7 | PRD | 0.00 | | | 500.00 | | | 750.00 | | | 1,000.00 | | | 1,250.00 | |
| 8 | Wind 1 | 0.00 | | | 0.00 | | | 1,200.00 | | | 1,200.00 | | | 1,200.00 | |
| 9 | Wind 2 | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 10 | | | | | | | | | | | | | | | |

**Figure P-132: Decision Cells for Base Case**

To simulate the situation without demand response, it is necessary only to set the cumulative capacity of demand response to zero in all periods. This is illustrated in Figure P-133.

PlnCap_0 = 0

| | N | R | S | AH | AI | AJ | AP | AQ | AR | AX | AY | AZ | BF | BG | BH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Sep-04 | Dec-0 | Sep-08 | Dec-08 | Mar-0 | Sep-10 | Dec-10 | Mar-1 | Sep-12 | Dec-12 | Mar-1 | Sep-14 | Dec-14 | Mar- |
| 2 | Capacity Data ID | | | | | | | | | | | | | | |
| 4 | CCCT Capacity | 0.00 | | | 0.00 | | | 610.00 | | | 610.00 | | | 610.00 | |
| 5 | SCCT Capacity | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 6 | Coal Capacity | 0.00 | | | 0.00 | | | 400.00 | | | 400.00 | | | 400.00 | |
| 7 | PRD | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 8 | Wind 1 | 0.00 | | | 0.00 | | | 1,200.00 | | | 1,200.00 | | | 1,200.00 | |
| 9 | Wind 2 | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 10 | | | | | | | | | | | | | | | |

**Figure P-133: Decision Cells for Case Without DR**

Finally, the case where demand response is fixed at 500MW in all years requires only that the cumulative capacity be set to that value and held across the study. See Figure P-134, below.

PlnCap_0 = 0

| | N | R | S | AH | AI | AJ | AP | AQ | AR | AX | AY | AZ | BF | BG | BH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Sep-04 | Dec-0 | Sep-08 | Dec-08 | Mar-0 | Sep-10 | Dec-10 | Mar-1 | Sep-12 | Dec-12 | Mar-1 | Sep-14 | Dec-14 | Mar- |
| 2 | Capacity Data ID | | | | | | | | | | | | | | |
| 4 | CCCT Capacity | 0.00 | | | 0.00 | | | 610.00 | | | 610.00 | | | 610.00 | |
| 5 | SCCT Capacity | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 6 | Coal Capacity | 0.00 | | | 0.00 | | | 400.00 | | | 400.00 | | | 400.00 | |
| 7 | PRD | 0.00 | | | 500.00 | | | 500.00 | | | 500.00 | | | 500.00 | |
| 8 | Wind 1 | 0.00 | | | 0.00 | | | 1,200.00 | | | 1,200.00 | | | 1,200.00 | |
| 9 | Wind 2 | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | | | 0.00 | |
| 10 | | | | | | | | | | | | | | | |

**Figure P-134: Decision Cells for Case With 500MW DR**

With these modifications, the model creates the three feasibility spaces described above.

## Wind

Two prominent themes for wind generation studies dealt with the assumption of declining capital cost and with the opportunity cost for not pursuing wind.

## Non-Decreasing Wind Cost

Chapter 5 of the Final Plan and Appendix I describe key generation cost assumptions. The Plan assumes wind construction costs decline at 1.6 percent per year. To understand the extent to which this declining-cost assumption might be driving the results of the model, a study [**51**] assumed that the wind costs did not decline from today’s levels.

As expected, the overall system costs increased dramatically (see Figure P-135), and there was some reduction of wind along the efficient frontier, but wind still appeared in 2013 and develops to its full potential (5000 MW) by the end of the study. Coal developed in somewhat more plans near the least-risk end of the efficient frontier, but never by more than 400MW. Conservation commanded more of a premium closer to the least-risk end of the efficient frontier.

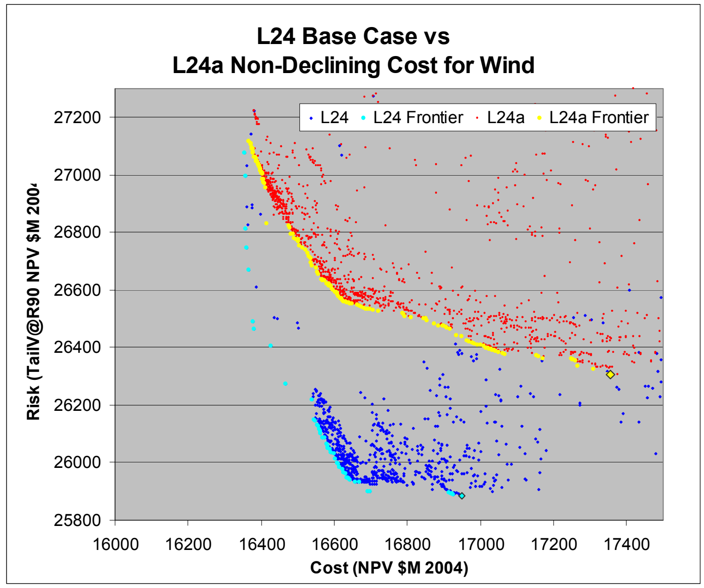
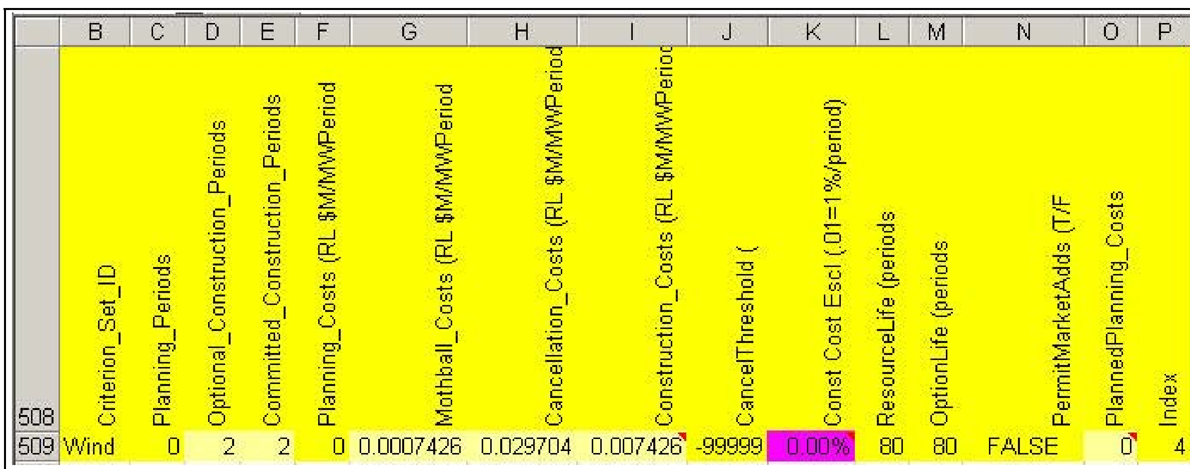



**Figure P-135: Feasibility Spaces for Non-Declining Wind Cost Study**

The rate of construction cost escalation is a parameter specified in the workbook. The cell {{K509}} of the base case stipulates that the quarterly escalation rate is -0.408 percent. The Council performed this sensitivity study merely by setting this value to zero, as illustrated in Figure P-136. Note that the row containing data labels has a modified format to make reading it easier.



| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 508 | Criterion_Set_ID | Planning_Periods | Optional_Construction_Periods | Committed_Construction_Periods | Planning_Costs (RL $M/MW/Period | Mothball_Costs (RL $M/MW/Period | Cancellation_Costs (RL $M/MW/Period | Construction_Costs (RL $M/MW/Period | CancelThreshold ( | Const Cost Escl (.01=1%/period) | ResourceLife (periods | OptionLife (periods | PermitMarketAdds (T/F | PlannedPlanning_Costs | Index |
| 509 | Wind | 0 | 2 | 2 | 0 | 0.0007426 | 0.029704 | 0.007426 | -99999 | 0.00% | 80 | 80 | FALSE | 0 | 4 |

**Figure P-136: Modified Cost Escalation for Wind**

## The Value of Wind

One study [**52**] examined the opportunity cost of ignoring wind as a capacity expansion option. This study removed wind generation as a candidate for system expansion from the base case.

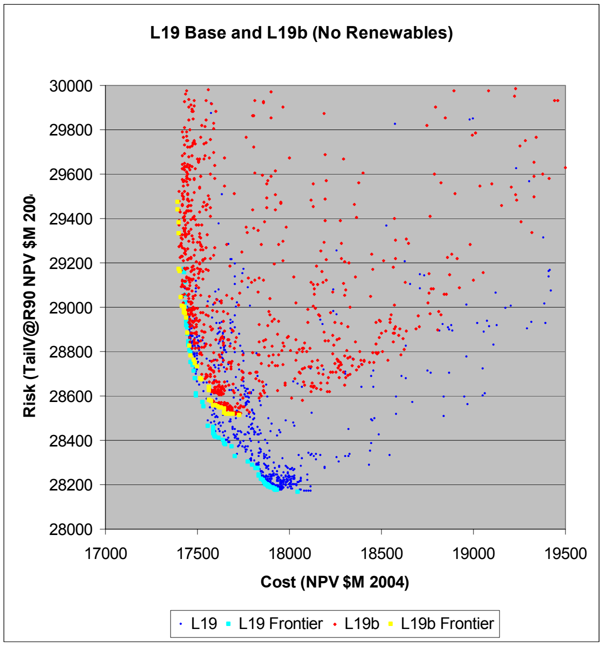



**Figure P-137: The Feasibility Space, Removing Wind As An Option**

As the section on the value of demand response suggests, *value* – in terms of cost reduction – typically *depends on the level of risk the region is willing to assume*. To understand value, therefore, we must consider the efficient frontier. At each level of risk the efficient frontier may shift different amounts to the left, or not at all. Figure P-137 illustrates this principle, with negligible cost shift near the least-cost end of the efficient frontier and significant variation in the least-risk plans.

We should not be surprised to see little or no value at the least-cost end. After all, wind generation is expensive today relative to expected, long-term equilibrium market prices. If the region were content to "ride the market," the right answer would be to build little or no wind – or any thermal resource for that matter. After all, the equilibrium price for wholesale electricity is the same as that for a CCCT. Why build when you can buy? This is the argument that the "Gas Price" and "Electricity Price" sections of this Appendix explore, and some would claim it is the fundamental assumption that led to the 2000-2001 energy crisis.

As risk mitigation becomes a consideration, however, the value grows. Moving to lower-risk plans, the difference in least-costs plans grows to about $200 million. Beyond the level of risk mitigation that maximizes the difference, however, the value is impossible to determine. Why is the value impossible to determine? Beyond that point, there are no plans *without wind* at any cost that provide the level of risk mitigation that plans *with wind* generation provide!

To create the feasibility space without wind generation, this study eliminated the optimizer's decision cells and constraints pertaining to wind. In the workbook, the values in the decision cells associated with wind are zero across the study. Because the optimizer cannot modify the decision cells, those zero values never change. The situation for the decision variables appears in Figure P-138; the absence of wind capacity constraints is evident in Figure P-139. For more detail about decision cells and how the optimizer modifies them to define a plan, see Appendix L, in particular the section "OptQuest Stochastic Optimization."

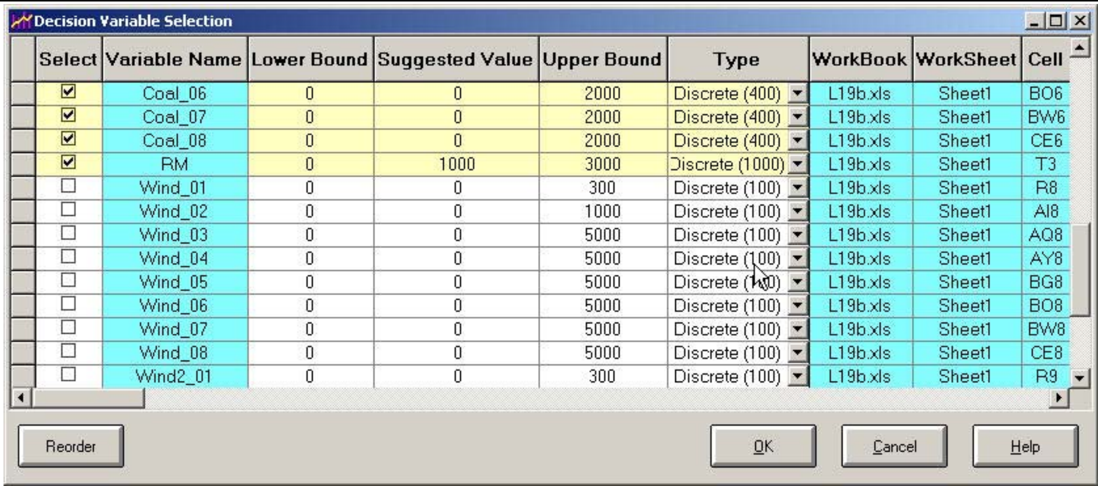



**Figure P-138: Optimizer Decision Variable for No Wind Generation**

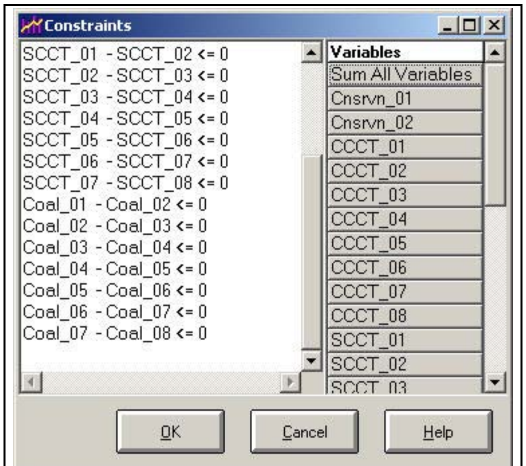



**Figure P-139: Optimizer Constraints for No Wind Generation**

Two other studies presented in this Appendix bear on the question of wind generation value. The section on $CO_2$ taxes, above, looks at the issues of how $CO_2$ tax, green tags, and production tax credits affect the value of wind. As expected, new wind generation constructed in less quantity and much later along the efficient frontier. Nevertheless, wind did appear in the least-risk plans. Despite its cost, low availability factor, and disadvantage with respect to dispatchable generation, it still provides a hedge against fuel cost excursions and has planning flexibility advantages, like short lead-time and modularity.

The second sensitivity study that bears on the value of wind generation is one that examines the role of planning flexibility for conventional coal-fired generation. In that study, the $CO_2$ tax, green tags, and production tax credits again are zero, but coal is given a shorter construction cycle. Coal then becomes competitive with wind. This study is the topic of the next section.

## Conventional Coal

Conventional coal faired poorly in most studies, entering as a construction option only in the most risk-averse plans and then only in fairly small amounts, typically 400 MW or less. Various studies indicated that the problems with coal were associated with $CO_2$ taxes, long construction lead times, and to some extent, PTC and green tag programs that make wind more competitive. If this is true, removing these factors should cause coal to appear on the efficient frontier. All regional model studies assumed, after all, that coal had several benefits, primarily stable and low fuel price.

One study [**53**] assumed no carbon tax, no green tag credit or PTC for wind, and a construction cycle for coal that matches that for a CCCT. The construction cycle, after siting and licensing, is two years. Total overnight cost of coal, however, are the same as in the basecase, only compressed into the shorter construction interval.

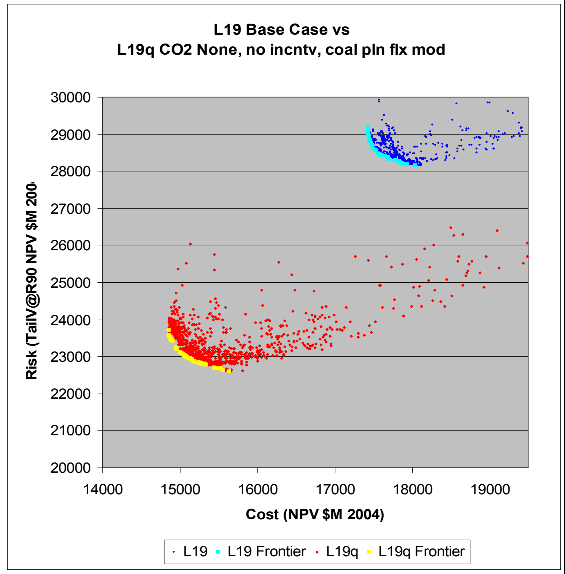



**Figure P-140: Removing the Barriers to Coal Development**

The study appears to corroborate the view that the perceived disadvantages drive the results. The feasibility space (Figure P-140) is generally less risky and less costly due to the elimination of the $CO_2$ tax and reduction of the coal plants' construction cycle. Moreover, coal plants appear in almost all of the efficient frontier's plans, being absent in only the risk-indifferent, least-cost plans (upper left hand extreme of the trade-off curve). This stands to reason, as few resources except some inexpensive conservation appear among these plans. At the other extreme of the curve, least-risk plans have substantial amounts of coal, adding up to 400MW of coal-fired generation by 2012 and up to 2000MW by 2015. (In this particular study, coal was constrained at 2000MW from 2015 until the end of the study, so it is not possible to determine whether or how much additional coal the model might have added otherwise.) CCCT capacity and conservation develop, too. Coal displaces primarily wind capacity development.

To perform this study, {{rows 74 ($CO_2$ tax), 81 (PTC), and 83 (green-tag value)}} are hard-wired to zero. The study accelerates the rate at which cost accumulates during construction achieve the same overnight cost in the shorter construction cycle [**54**]. The resulting values modify the construction cost information in {{row 483}}, as shown in Figure P-141. (Appendix L, section "Parameters Describing Each Technology," provides an interpretation of these parameters.)

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 482 | | Criterion_Set_ID | Planning_Periods | Optional_Construction_Periods | Committed_Construction_Periods | Planning_Costs (RL $M/MWPeriod^2) | Mothball_Costs (RL $M/MWPeriod^2) | Cancellation_Costs (RL $M/MWPeriod^2) | Construction_Costs (RL $M/MWPeriod^2) |
| 483 | | Coal Criter | 0 | 4 | 4 | 0 | 0.000593 | 0.023708 | 0.005927 |
| 484 | | | | | | | | | |
| 485 | Original | Coal Criter | 0 | 5 | 9 | 0 | 0.000339 | 0.013547 | 0.003387 |

**Figure P-141: Cost Data Cells in the Workbook**

A separate study shows that while eliminating $CO_2$ tax, PTC, and green tags alone does result in some coal construction, the construction levels are relatively low. (See the sensitivity study "No $CO_2$ Tax or Incentives for Wind," above.) Those results, combined with the subject study, suggest that the relative lack of ***planning and construction flexibility*** associated with coal plants is a major source of risk and cost.

## Larger Sample of Futures

As explained in the first chapter of this Appendix, Monte Carlo simulation provides many advantages for modeling uncertainty. One of the disadvantages, however, is that one must estimate the number of games necessary to guarantee a given level of estimate accuracy. Both the statistics that the regional model uses, mean cost and $TailVaR_{90}$, are averages and therefore have well-understood statistical properties. Because the regional model used 750 futures, the estimate of the mean cost was relatively precise: where the standard deviation of costs associated with a given plan is on the order of $6 Billion, the standard deviation of the mean estimate is about $220 Million. While the tail is smaller, however, the sample of the tail has only 75 games, so the precision in the $TailVaR_{90}$ statistic is not much better.

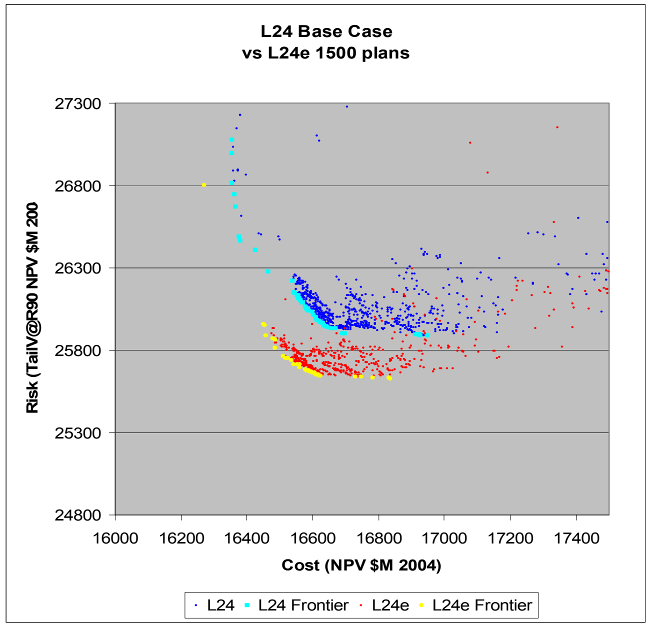



**Figure P-142: Increased Number of Futures**

Given the uncertainty associated with these statistical samples, the Council took several steps to assure that the results are representative. For example, Staff examined plans that lie off the efficient frontier. The section "Portfolio Model Reports And Utilities" of Appendix L, for example, explains how reports are marked to reveal not only the plans lying on the efficient frontier, but also those lying within $250Million NPV cost and risk from the efficient frontier. In particular, Staff studied these plans, searching for patterns or strategies that differed from those on the efficient frontier.

Staff also reproduced the final study using 1500 futures [**55**]. To our surprise, there did appear to be some differences between the two approaches. First, both cost and risk appeared to improve. (See Figure P-142.) The magnitude of the improvement, however, is consistent with sample variation. For example, Figure P-143 shows the average of N random values drawn from a normal distribution with mean 100 and standard deviation of 100 [**56**]. The value on the horizontal axis is N. At around 750, the estimate of the average is off about two percent. If the standard deviation of the costs associated with plans is about $6 B, two percent corresponds to about $120 M. Figure P-144 demonstrates that this is about the effect on the 192 plans that both the base case and the sensitivity case evaluated [**57**]. More important, perhaps, is that the position of plans relative to the efficient frontier are, by and large, unchanged. In particular, of the 50 plans on or within $250M of the efficient frontier, the range of costs differences for 49 plans is $99M to $108M ($9M wide) and the range of risk differences is $206M to $280M ($74M wide). Thus, the shifts are very regular. (The one plan in 50 that fell outside these ranges was associated with a high-risk plan.) Figure P-144 identifies the 50 plans lying near the efficient frontier with larger, pink points.

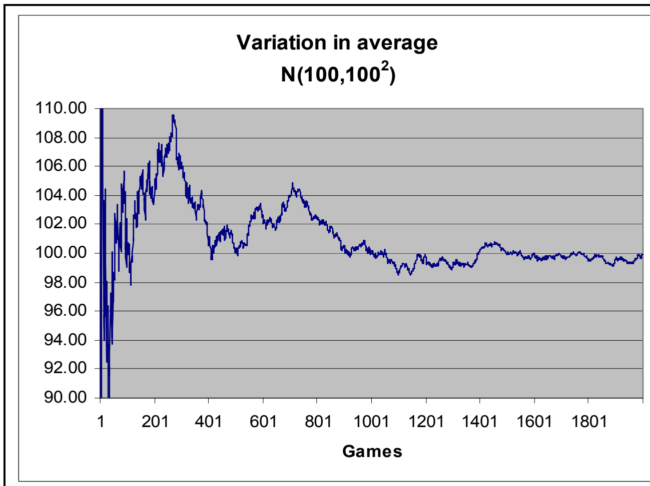



**Figure P-143: Variation in Mean**

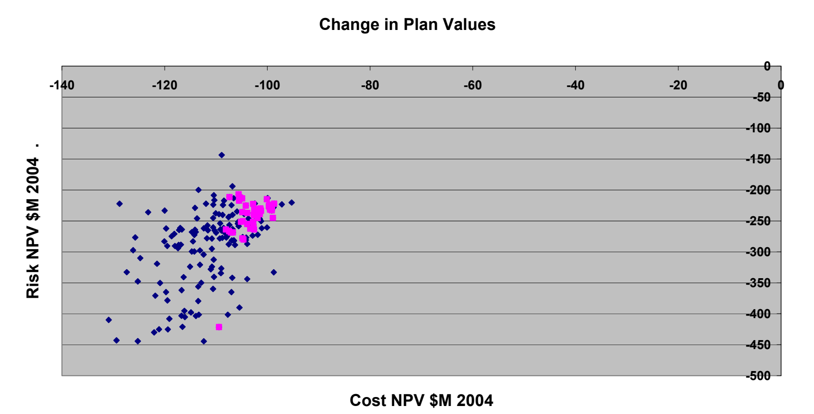



**Figure P-144: Consistent Effect on Cost and Risk of Plans**

A second difference observed in the sensitivity study was minor difference in the make-up of plans on the efficient frontier. While coal-fired power plants still appeared in plans near the efficient frontier, none of the plans on the efficient frontier had this resource. More lost-opportunity conservation also appears in the plans on the efficient frontier, and it merits an additional 10-mill/kWh premium. The reason for these differences in plans on the efficient frontier may simply have been that the sensitivity study had fewer plans than did the final base case (827 vs 1010) and the optimizer had not yet found the best strategies. Because doubling the number of futures increased the study time proportionally, however, the sensitivity case had to be ended prematurely.

While the results somewhat different than expected, the study did not contradict the results suggested by the base case. The plan recommended by the Council would appear very close to, if not on, the efficient frontier near the least-risk end of the efficient frontier.

# *Glossary*

uncertainty
innovation
GBM
Monte Carlo simulation
Spinner graphs

[WORK IN PROGRESS]

# Figures

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[WORK IN PROGRESS]

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**38** L19g High Gas Price
**39** L24f Lower Electricity Price Volatility
**40** L19i CO2 None and no incentives
**41** L19t CO2 McCain-Lieberman
**42** See, for example, the Base Case for L19
**43** L19e CO2 50% & tiered, L19f CO2 50% & tiered + NG inc $1.50, L19n CO2 25% & tiered, and L19p CO2 25% & tiered + NG inc $1.50. The tiered approach was adopted in the Final Plan.
**44** L28g Value of IPPs and notes.
**45** L24i Contracting the IPP out of the region and notes.
**46** L28 basecase, L28b Mildly Restricted Conservation and notes, and L28c Severely Restricted Conservation and notes.
**47** ConvertingOvernightToPeriodCosts_v06 for DR only.xls
**48** L28d No DR and notes.
**49** L28j 500MW DR and notes.
**50** Graph is developed in DR Study.xls
**51** L24a Non-declining costs for wind
**52** L19b Renewables=0 and notes
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