
# Sixth Northwest Conservation and Electric Power Plan

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# Sixth Northwest Conservation and Electric Power Plan


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## INTRODUCTION

Since the millennium, the trend for fuel prices has been one of uncertainty and volatility. The price of crude oil was $25 a barrel in January of 2000. In July 2008 it averaged $127, even approaching $150 some days. Natural gas prices at the wellhead averaged $2.37 per million Btu in January 2000. In June 2008, the average wellhead price of natural gas averaged $12.60. Even Powder River Basin coal prices, which have traditionally been relatively stable, increased by about 50 percent in 2008. Fuel prices weakened significantly in the last half of 2008, but remain high by standards of the 1990s.

Fuels are not the only commodities that have experienced a period of very high prices; metals, concrete, plastics, and other construction materials have all experienced increased prices in the last few years. Factors contributing to higher commodity prices in general, and to fuel prices in particular, include: rapid world economic growth, declining value of the dollar, slow response of conventional energy supplies to higher prices, continuing conflict in the Middle East, uncertainty about the direction of climate change policy, and changing commodity market dynamics. The recession has also moderated these other commodity prices.

The relative contribution of these factors to increased prices is uncertain, as is the direction of change for many of them. Conventional sources of oil and natural gas in North America are expected to be difficult to expand significantly. Growth in supplies, therefore, will increasingly depend on the development of unconventional sources and liquefied natural gas (LNG) imports. With the higher natural gas prices of recent years and technological improvements in drilling, nonconventional supplies of natural gas have expanded rapidly. A significant amount of LNG import capability has been added and has contributed significant new supplies in times of high prices. Both of these sources are expanding, but all new investments in energy infrastructure are controversial. In addition, the investments can be slowed by large uncertainties concerning energy climate change policies.

At the same time, high prices have also brought about changes on the demand side of the market. High prices encourage conservation in the sense of using less, and they also create incentives to invest in energy-efficient technologies. Such responses to high prices set in motion the forces to reduce prices. Over time, these cycles are likely to reach higher high points and higher low points, forming a series of upward-stepping cycles. Investments in new supplies and energy efficiency also tend to follow these cycles. Expectations that prices will fall from high points in the cycle make consistent investments in supply and energy efficiency less robust.

Accurately forecasting future fuel prices is an impossible task. The history of such forecasts is that even long-term forecasts tend to assume that current conditions will, to a large extent, continue. During periods of high fuel prices, forecasts tend to increase, and during periods of low prices, they tend to decrease. The Council's practice has been to recognize the inherent uncertainty and build power plans that minimize the risk from price forecasts that turn out to be wrong.

# DEALING WITH UNCERTAINTY AND VOLATILITY

In spite of their uncertainty, fuel prices are an important consideration for electricity planning. Fuel prices affect both the demand for, and the cost of, electricity. As an important determinant of electricity cost, they also affect the cost-effective amount of efficiency improvement through the avoided cost of alternative generation resources. The uncertainty and volatility of fuel prices create risks for the Northwest power system. These risks and others are addressed in the Council's electricity planning.

The range of trend forecasts discussed here represents only one aspect of fuel price uncertainty addressed in the Council's power plan. The low to high trend forecasts of fuel prices are meant to reflect current analysis and views on the likely range of future prices, but the plan's analysis also considers variations expected to occur around those trends. In the Fifth Power Plan this additional volatility was only applied to natural gas prices. This was because oil prices are insignificant as either a demand alternative to electricity or a generation fuel. Coal prices are a significant determinant of electricity costs because of existing coal-fired generation, and coal is also a potential future source of energy. However, coal prices had not experienced the same level of uncertainty and volatility as oil and natural gas prices, and were therefore not considered to be a major source of risk and uncertainty.

The plan reflects three distinct types of uncertainty in natural gas prices: (1) uncertainty about long-term trends, (2) price excursions due to disequilibrium of supply and demand that may occur over a number of years, and (3) short-term and seasonal volatility due to such factors as temperatures, storms, or natural gas storage levels. The forecasts discuss only the first uncertainty. Shorter-term variations are addressed in the Council's Resource Portfolio Model analysis.

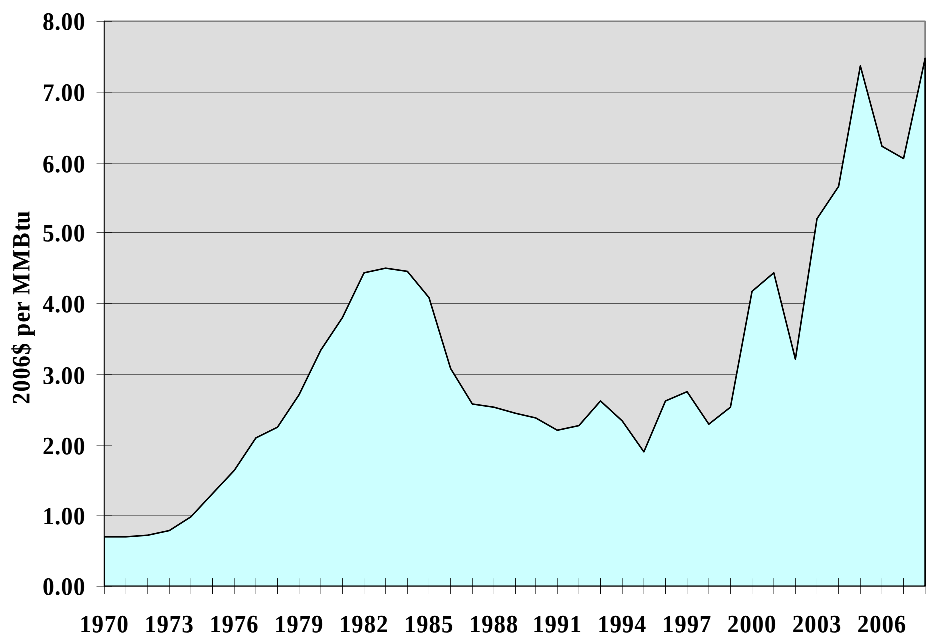
There are additional uncertainties to the cost of fuel from the effects of climate policies, such as CO2 costs from taxes or a cap and trade structure. These additional costs are explicitly treated in the Council's portfolio model and affect the cost of using various fuels, but are not a part of the commodity prices discussed in this appendix.

# NATURAL GAS

## *Background*

The Council's forecast of natural gas prices starts with a national level commodity price, the average natural gas wellhead price in the lower-48 states. A look at the past behavior of these prices gives perspective for the forecasts. Figure A-1 shows wellhead natural gas prices (in constant 2006 dollars per million Btu) from 1980 through 2007. Following deregulation of natural gas markets in the late 1980s, prices fell to nearly $2.30 and remained near that level for all of the 1990s. After 2000, prices began to increase rapidly and became highly volatile. By 2008 the wellhead price of natural gas averaged $8, nearly four times the levels of the 1990s. In some months since 2000, prices have reached over $10 as they responded to the effects of hurricanes, storage levels, oil prices, and other market effects. With this historical context, it is difficult to predict future natural gas prices with any certainty.

**Figure A-1: Historical Wellhead Natural Gas Price**



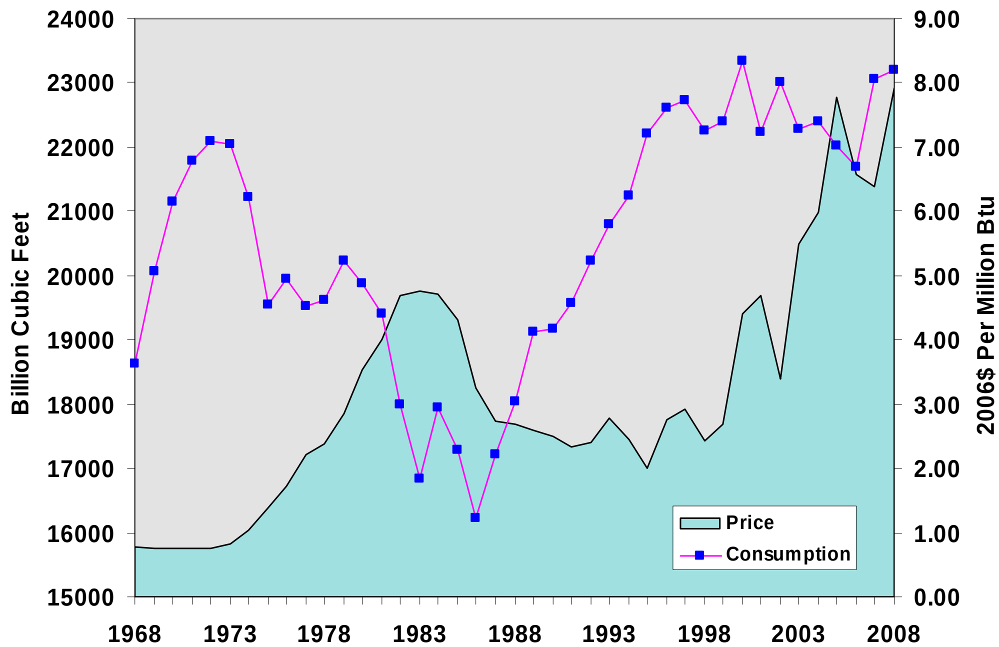

The Council's forecast of natural gas prices is informed by national level forecasts of prices from other organizations that specialize in analysis of fuel commodity markets. Such forecasts rely on estimates of the fundamentals of supply, demand, and the transportation capacity to move natural gas from supply sources to demand locations. Nevertheless, these forecasts are far from stable over time since they tend to respond to the most recent conditions, which can change drastically. The variation of forecasts from various organizations helps scale the uncertainty between the high and low forecasts. However, the range is also informed by analysis of long term trends in prices and analysis of how prices respond to changing conditions over long periods of time.

Forecasting future fuel prices is particularly difficult following large changes in markets, which is the case with the natural gas market since 2000. It requires sorting out temporary influences from longer-term factors that are expected to persist into the future. For example, regulation of natural gas supplies dampened the supply response to the growing demand for natural gas in the early 1980s, leading to rapid price escalation. Regulatory incentives to find new natural gas supplies, but not increase production from existing supplies, resulted in a slow supply response, but also created large new supplies in the longer term. When natural gas was deregulated in the late 1980s, prices collapsed due to the so-called "gas bubble" and remained low throughout the 1990s. During this time, low prices were expected to continue for many years and estimates of the cost of finding new natural gas were low.

By the end of the 1990s, the more permanent effects of deregulated natural gas supplies were becoming clear. Companies no longer held large inventories of proven reserves and as excess reserves declined, prices became more volatile. This volatility was exacerbated by the development of spot and futures trading markets. Without significant changes to natural gas market regulation, this volatility is expected to be a long-term feature of these markets. As noted earlier, that volatility is reflected in the Council's Power Plan, but this forecast addresses only a range of long-term price trends around which such volatility will occur. For example, the portfolio model includes short periods of time where prices can substantially exceed the high trend price forecast.

It is important to understand that the collapse of prices in the late 1980s was not all due to a supply bubble; there was also a significant reduction in natural gas use. During the two decades prior to 1970, natural gas use had grown rapidly as supplies expanded and natural gas pipeline expansion made the supplies available to users. However, as natural gas prices escalated during the 1970s (more than quadrupling), demand for natural gas dropped precipitously. Similarly, as prices dropped following deregulation and remained low during the 1990s, demand grew, but failed to return to its previous 1973 high level until 1995. Figure A-2 shows these patterns. Also evident in Figure A-2 is the moderating effect of recent natural gas price increases on natural gas use since 2000.

**Figure A-2: Historical Natural Gas Prices and Consumption**




# *Price Forecasts*

## U.S. Natural Gas Commodity Prices

There are several characteristics of the recent price increases that have implications for the future long-term trends in natural gas price. On the supply side, it has become clear that conventional natural gas supplies are increasingly difficult to expand. This does not mean that supply will not be able to expand. Recently, there have been significant increases in nonconventional supplies of natural gas, such as coal-bed methane and shale deposits like the Barnett Shale in North Texas, Haynesville in East Texas, Fayetteville in Arkansas, and Montney and Horn River in British Columbia. It is estimated that such nonconventional supplies of natural gas now account for nearly half of U.S. natural gas production. The Potential Gas Committee recently increased its estimates of natural gas resources by 35 percent reflecting new feasibility of recovering shale gas.[1] Production from nonconventional sources has been made feasible by improved drilling and production technologies, but these are also more expensive. For example, development of new shale natural gas supplies is estimated to cost between $5 and $7 dollars per million Btu.

Another factor with implications for the long-term trend of natural gas prices is on the demand side of the equation. The significant reduction in demand during the 1970s was partly due to the ability to switch industrial uses of natural gas to alternative fuels. With today's climate concerns, the use of oil and coal are becoming constrained and limit the ability of industries (including power generation) to reduce natural gas use as prices increase. Further, the response to climate concerns and regulations is expected to increase the demand for natural gas. Examples include electric vehicles, where the electricity generation is likely to require increased

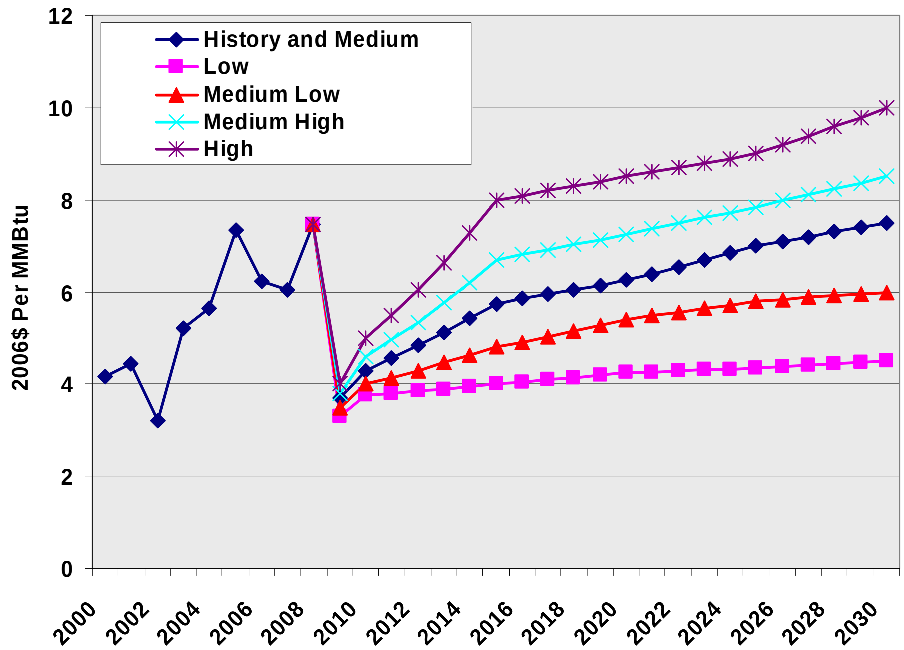
[1] See Colorado School of Mines press release at http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base

amounts of natural gas, and biofuels, where natural gas is required to produce ammonia fertilizer to grow biofuel crops and provide process heat to refine the biofuels.

Cycles will continue in the future as markets develop and respond to changing supply and demand conditions. The large drop in natural gas prices in 2009 is a good example. However, the view expressed in the central part of the Council's natural gas price forecast range is that the trend through these future cycles will be upward. Given that the market appears to be starting from a low point in a commodity cycle, most of the forecast range includes increases from recent levels. Trend prices do not fall back to the $2.30 natural gas prices of the 1990s, even in the lowest price forecast.

Figure A-3 shows the range of U.S. wellhead price forecasts proposed for the Sixth Power Plan. As shown in the graph, natural gas prices nearly doubled between 2000 and 2008. Not shown, is the doubling of prices in 2000 from the previous few years. Thus, 2008 prices were nearly four times their levels from 10 years ago.

**Figure A-3: U.S. Wellhead Natural Gas Price Forecast Range**




The medium case forecast shows prices recovering from the 2009 drop to $5.75 (in 2006 prices) by 2015, and then trending upward slowly, reaching $7.50 by 2030. Note that $7 is a higher natural gas price than any historical year except 2005, which was affected by Hurricanes Katrina and Rita, and 2008, which included oil prices that reached nearly $150 per barrel in the early summer months. Nevertheless, these prices represent the current expectations of many experts in the fuel markets, including many of the members of the Council's Natural Gas Advisory Committee.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case prices increase to $10 by 2030. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely impact the economy. For long-term trend analysis, the stress on prices from increased need to expand energy supplies is considered the dominant relationship. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world LNG capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for demand reductions are very limited.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future where world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid progress in renewable electric generating technologies, thus reducing the demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas producing areas.

The intermediate cases are variations on the medium case that are considered reasonably likely to occur. The medium-high case would contain elements of the high scenario, however not to the same degree. Similarly, the medium-low case would contain some of the more optimistic factors described for the low case.

In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. Table A-1 shows the range of natural gas price trend forecasts for selected years. In the Council's portfolio analysis, however, prices at any given time may fall anywhere within, or even outside, the range shown in Table A-1.

**Table A-1: U.S. Wellhead Natural Gas Price Forecasts (2006 Dollars Per Million Btu)**

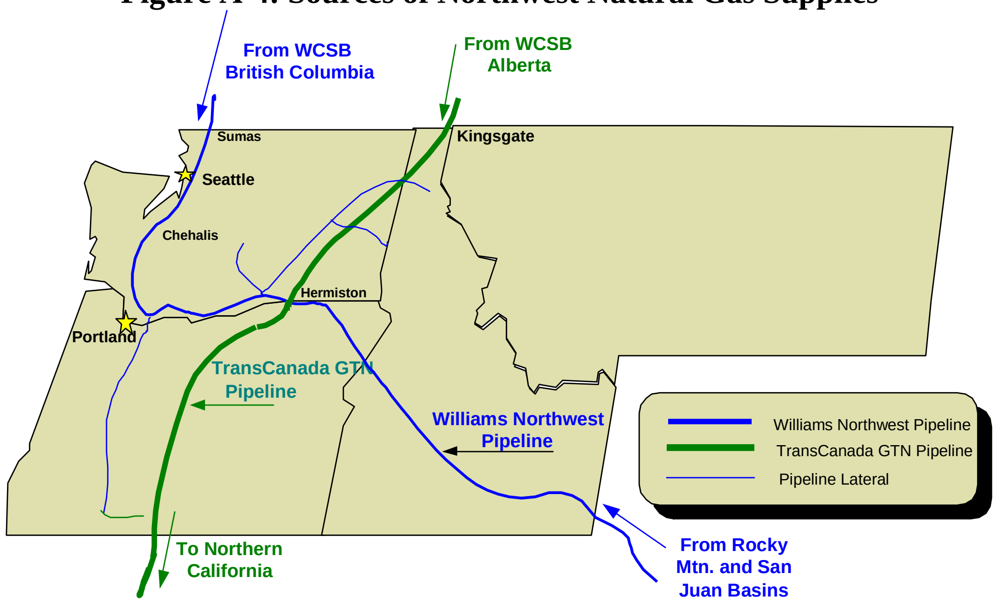
| | Low | Medium Low | Medium | Medium High | High |
|---|---|---|---|---|---|
| **2008** | | | 7.47 | | |
| **2010** | 3.75 | 4.00 | 4.30 | 4.60 | 5.00 |
| **2015** | 4.00 | 4.80 | 5.75 | 6.70 | 8.00 |
| **2020** | 4.25 | 5.40 | 6.25 | 7.25 | 8.50 |
| **2025** | 4.35 | 5.80 | 7.00 | 7.85 | 9.00 |
| **2030** | 4.50 | 6.00 | 7.50 | 8.50 | 10.00 |
| **Growth Rates** | | | | | |
| **2007 - 15** | -7.51% | -5.38% | -3.22% | -1.35% | 0.86% |
| **2007 - 30** | -2.18% | -0.95% | 0.02% | 0.56% | 1.22% |

## Northwest Natural Gas Supplies and Price

Given a forecast of U.S. level commodity prices, the next step is to estimate the cost of natural gas within the Pacific Northwest region and the rest of the Western United States. This is necessary because there is significant regional variation in natural gas prices.

Natural gas supplies for the Pacific Northwest come from two sources: the Western Canada Sedimentary Basin in Alberta and Northeastern British Columbia, and the U. S. Rocky Mountains. Natural gas from these areas is delivered into the region by two pipelines. The Williams Northwest Pipeline delivers supplies from the U.S. Rocky Mountains as well as down from Sumas at the B.C. border. The other pipeline is TransCanada Gas Transmission Northwest, which brings supplies from Alberta, through the Northwest and on down to the California border. Figure A-4 illustrates the Northwest's natural gas delivery system.

**Figure A-4: Sources of Northwest Natural Gas Supplies**




In the past, the Northwest has been fortunate to be linked to expanding natural gas supply areas that had limited transmission to other areas. This resulted in natural gas prices in the region that are lower than most other areas of the country. In recent years, the ability of WCSB to expand production has decreased and it is projected that imports from that area to the U.S. are unlikely to be able to meet growing natural gas demand in the future. A more optimistic view of the ability of Western Canada to continue providing natural gas to the region would recognize that there is substantial coal bed and shale gas potential in the WSCB that could be developed. Further the internal demand for natural gas for oil sands development, could be substantially replaced by liquefaction of petroleum coke (a by product of oil sands refining), development of nuclear technologies to provide electricity and steam for oil sands production and processing, or cogeneration of electricity from natural gas use.

The Rocky Mountain supply area is still a growing production area, however, and its prices are still relatively low. New pipelines from the Rockies to the east are likely to reduce the price advantage of Rockies natural gas unless supplies expand even faster than pipeline capacity. The pipeline capacity to bring Rockies gas to the Northwest is constrained and will need to be expanded for the Northwest to be able to access growing Rockies supplies. There are active proposals to expand pipeline capacity from the Rockies to the Northwest. The Sunstone pipeline would bring gas from the Opal hub in Wyoming to Stanfield in eastern Oregon, and the Blue Bridge project would expand pipeline capacity from Stanfield to western Oregon. Two other pipeline proposals, Bronco and Ruby, would bring natural gas from Opal to the Oregon-

California border at Malin. There are also proposals for expanding pipelines from the Rockies to Southern California and to the East.

Liquefied natural gas (LNG) is another potential source of future natural gas supplies. There are currently three proposed LNG import terminals in the region: Bradwood Landing and Oregon LNG near the mouth of the Columbia River, and Jordan Cove LNG in Coos Bay, Oregon. Each of these has the potential to supplement natural gas supplies to the Pacific Northwest in the future, but it is doubtful if more than one of these proposals will be built. Each would involve some pipeline construction and expansion to deliver natural gas into the Northwest's pipeline systems.

Another potential for increasing Northwest natural gas supplies is a proposed pipeline to bring natural gas from Alaska through Canada and into the Pacific Northwest. Alternative proposals for such a pipeline have been vying for support for several years. At best, completion of an Alaskan pipeline is probably 10 years in the future.

There is general agreement that natural gas will have to play an important role in electricity supplies for the Council's planning horizon. The cost of that natural gas will depend on the demand for natural gas and the supply and deliverability to the region. The deliverability of natural gas depends not only on access to supplies and pipeline capacity, but also on storage capability and other natural gas peaking resources like line pack, LNG storage, and interruptible demand.

The growing use of natural gas for electricity generation will require increased coordination between the electricity and natural gas industries. This is particularly true for natural gas used for peaking generation or ancillary services. Natural gas is currently scheduled on a daily basis, but electricity is scheduled on an hourly basis with constant adjustment to actual demands through load following and regulation services. Increasing amounts, and perhaps different forms, of natural gas flexibility within the day may be required as the use of natural gas increases for providing flexibility and ancillary services for the electricity sector.

In order to plan for the region's electricity needs, the Council must forecast natural gas prices, not only in the Northwest, but also in other areas of the West. To do this, the Council has developed relationships among the various natural gas pricing hubs in the West. Most relevant to the Northwest are prices at the AECO-NIT pricing hub in Alberta, the Sumas hub on the Washington-B.C. border, and the Rocky Mountain hub.

Figure A-5 shows the medium case forecasts for average wellhead prices, and prices at the Henry Hub, Sumas, AECO, and the Rocky Mountains trading hubs. Henry Hub, Louisiana is the pricing point for the New York Mercantile Exchange spot and futures markets for natural gas. Table A-2 shows the values for selected years. Figure A-6 shows the basis differentials between Henry Hub and the three regional pricing hubs. A negative basis differential means that local prices are lower than the Henry Hub price. Historical relationships that were estimated among natural gas pricing hubs are used to predict future basis differentials. Consistent monthly or seasonal differences are captured in the relationships, but differentials are likely to change over the future in ways not reflected in these estimates. These changes will relate to pipeline expansions, shifts in demand, and expansions of supply that will occur at different times and rates. The forecasts will not capture these shifting factors directly, but the wide range of price forecasts and variations in those forecasts captured in the Portfolio Model will help measure the risks posed by such variations.

The forecast basis differentials reflect an expectation that Northwest natural gas prices will continue to be lower than prices in the Gulf of Mexico (Henry Hub) area. This is consistent with growing Rocky Mountain production, stable or possibly increasing Canadian production, and future pipeline capacity from Alaska. Development of LNG import capability within the region would also help keep Northwest supplies robust and prices more moderate, but in reality, these relative prices could shift in the future. Rapid development of LNG import capacity in the Gulf of Mexico and development of shale-based natural gas in Texas, Oklahoma, Arkansas, and the Appalachian Basin have the potential to shift regional price relationships and possibly reduce the Northwest's price advantage.

**Figure A-5: Medium Case Natural Gas Price Forecasts at Northwest Hubs**

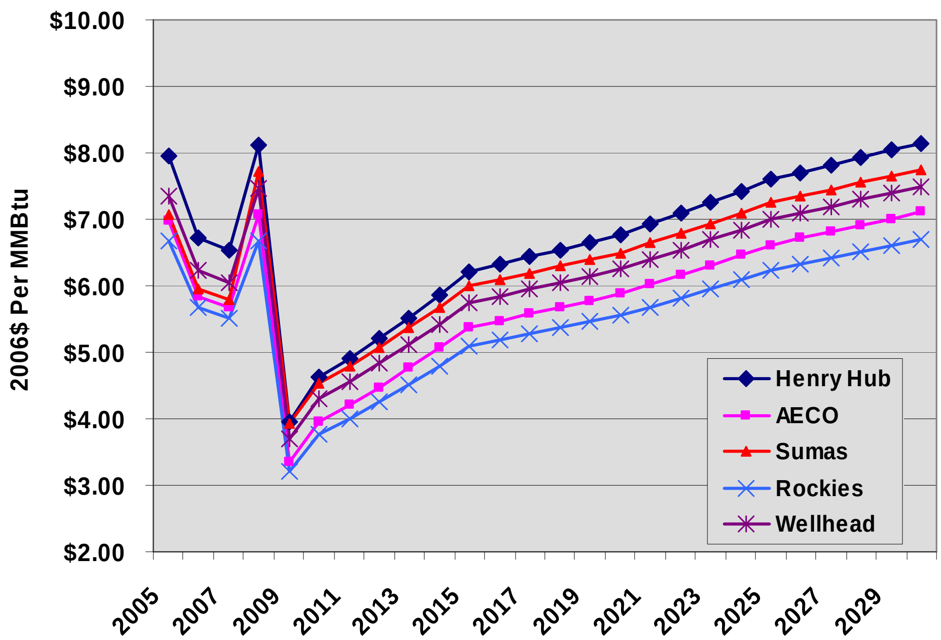
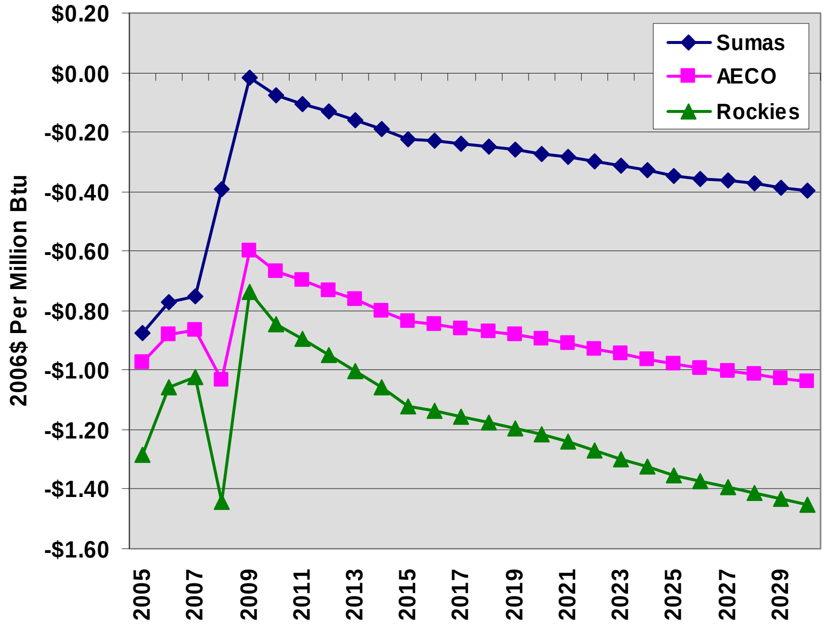



**Table A-2: Medium Case Prices Natural Gas Price Forecasts at Northwest Hubs (2006 Dollars per Million Btu)**

| | Wellhead | Henry Hub | AECO | Sumas | Rockies |
|---|---|---|---|---|---|
| **2008** | $7.47 | $8.12 | 7.08 | $7.72 | $6.67 |
| **2010** | $4.30 | $4.62 | 3.95 | $4.54 | $3.77 |
| **2015** | $5.75 | $6.22 | 5.38 | $6.00 | $5.10 |
| **2020** | $6.25 | $6.77 | 5.87 | $6.50 | $5.55 |
| **2025** | $7.00 | $7.60 | 6.62 | $7.25 | $6.24 |
| **2030** | $7.50 | $8.15 | 7.11 | $7.75 | $6.70 |
| **Growth Rates** | | | | | |
| **2008 - 15** | -3.67% | -3.74% | -3.85% | -3.55% | -3.77% |
| **2008 - 30** | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% |

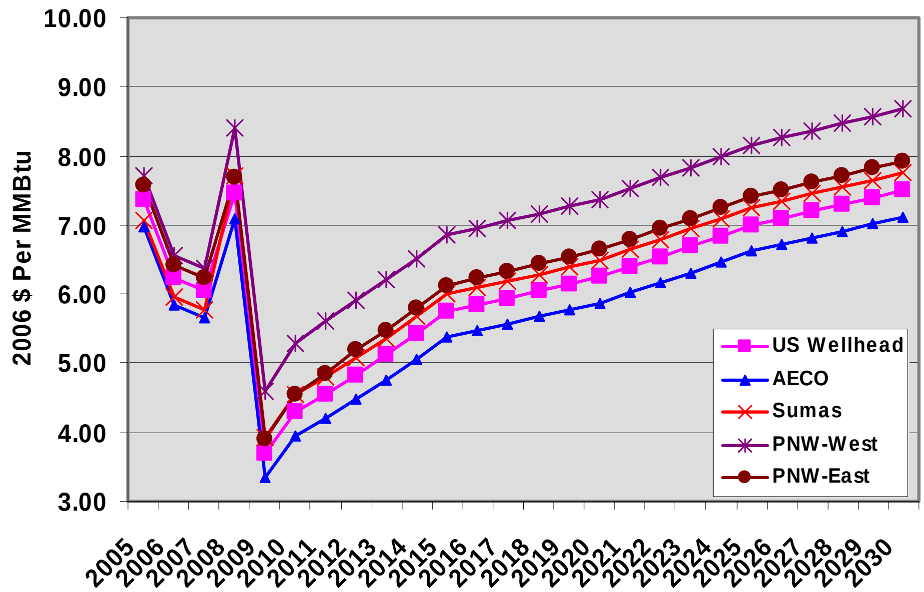
**Figure A-6: Medium Case Basis Differentials from Henry Hub Prices**




Forecasts of natural gas delivered to specific parts of the Pacific Northwest are based on the forecasts of hub prices at Sumas, AECO, and the Rockies plus estimated costs of transporting the fuel via regional pipelines. Pipeline costs include three general types of cost: capacity charges, commodity charges, and in-kind fuel costs. Capacity costs are by far the largest component of the transportation cost, and they are considered to be fixed costs. Existing users of natural gas are assumed to pay rolled-in pipeline capacity costs, but future power plants are assumed to pay incremental capacity costs, which reflect new pipeline capacity costs that escalate in real terms over time. The rate of escalation varies with the forecast case. Pipeline commodity and in-kind fuel charges are small and are a variable cost of natural gas, along with the cost of the gas itself.

Figure A-7 shows the medium case forecast of delivered natural gas prices for east and west of the Cascade Mountains compared to regional hub and wellhead prices. The cost of delivering natural gas from regional pricing hubs results in delivered prices that are similar in magnitude to Henry Hub prices. In addition to delivered natural gas prices for electric generation, the Council also forecasts retail natural gas prices to residential, commercial, and industrial users. More detailed price forecasts for each case appear in the appendix tables.

**Figure A-7: Incremental Natural Gas Prices Delivered to Regional Generation Facilities**




# OIL

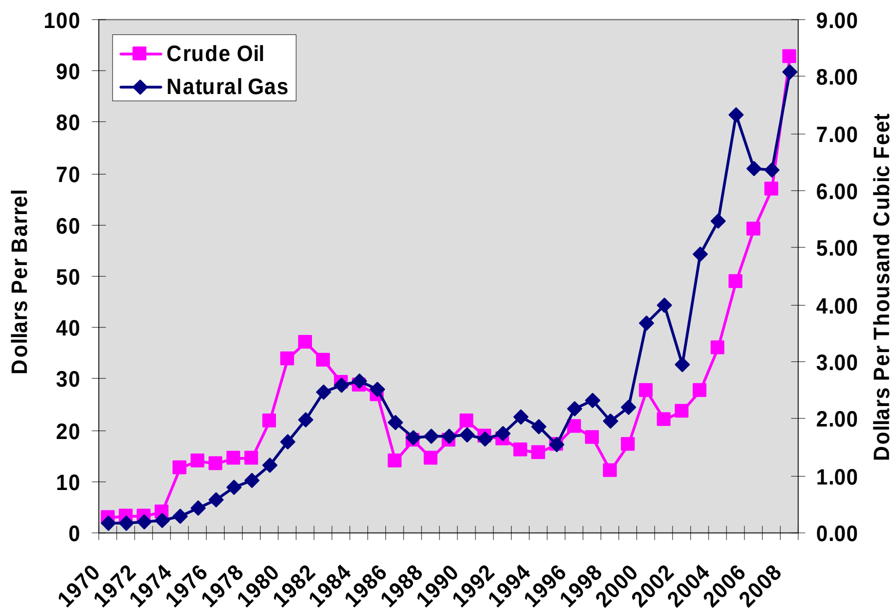
## *Background*

Forecasts of oil prices play a less direct role in the Council's Power Plan than natural gas prices. Oil is not a significant fuel for electricity generation, nor is it an important competitor with electricity in end-use applications. However, oil prices do have an influence on natural gas prices and other energy sources. The relationship is not exact, but as shown in Figure A-8, crude oil and natural gas commodity prices do tend to move together in the long-term. Oil is most significant as a transportation fuel. In that role, oil prices enter into determining delivered coal prices at various points in the West. This is due to the reliance on diesel fuel to run the trains that deliver coal from supply areas in Wyoming and Montana.

In the middle of 2008, world oil prices reached the highest level ever recorded. The price of $150 for a barrel of oil, experienced some days in 2008, was four times the previous highest average price for a year in 1981. Even adjusting the prices to equivalent year dollars, the prices in mid-2008 were double the previous peak. However, the $150 prices did not last long. By the winter months of 2008-09 oil prices fell to below $40 per barrel, but have recently increased to near $70 a barrel.

The factors contributing to these high oil prices are very similar to the factors listed as affecting high natural gas prices. Strong world economic growth, declining value of the dollar, unrest in the Middle East, 2005 hurricane damage, and declining domestic oil supplies. The large increases in oil prices since 2004 have changed many forecasters' views of the probable range of future oil prices.

**Figure A-8:  Historical Comparison of Crude Oil and Wellhead Natural Gas Prices**




## *Oil Price Forecast Range*

The oil price forecast proposed here is dramatically different from the forecast included in the Council's Fifth Power Plan.  The lowest case forecast in this paper is higher than the medium forecast in the last plan.  The entire forecast range, shown in Figure A-9, is much wider, reflecting increased uncertainty about future oil prices, especially on the high side of the range.

The medium forecast of world oil prices, defined as refiners' acquisition cost of imported oil, varies between \$65 and \$80 dollars per barrel (2006 dollars), higher than prices at the end of 2008, which were partially influenced by the global financial crisis and recession.  Prices generally fall following a period of extremely high prices as new sources of supply, substitution of other energy sources, and reduced demand bring markets into balance.  However, as oil production increases, more expensive sources of oil are required so that over time, prices ratchet upward.  Uncertainty about oil supplies and their costs, the effects of new technologies on supplies and uses, climate policies, and political factors in oil producing countries create large uncertainties about future oil prices, and therefore, a large range of price forecasts.

The high price case is unlikely in the long term because of the alternative supplies and reductions in use that are likely to occur at such high prices.  There are still ample supplies of conventional oil in the world, but its production is currently restricted by turmoil in the Middle East and the immaturity of the economies of former Soviet Union states.  On the demand side, very high oil prices will stimulate improved efficiency and possibly reduced economic growth.  In the years following the high oil prices of the 1970s and early 1980s, the energy intensity of the U.S. economy decreased by half, from 18.0 trillion Btu per billion dollars of Gross Domestic Product (2000\$) in 1970, to 8.8 in 2007 (see Figure A-10).  As the world continues to tackle the climate change issue, improved efficiency and expanded use of renewable energy sources will grow and further reduce the demand for oil in the long run.  Uncertainty about the amount of supply and demand adjustments and their costs contribute to the wide range of possible future oil prices.

**Figure A-9: World Oil Prices: History and Forecast**

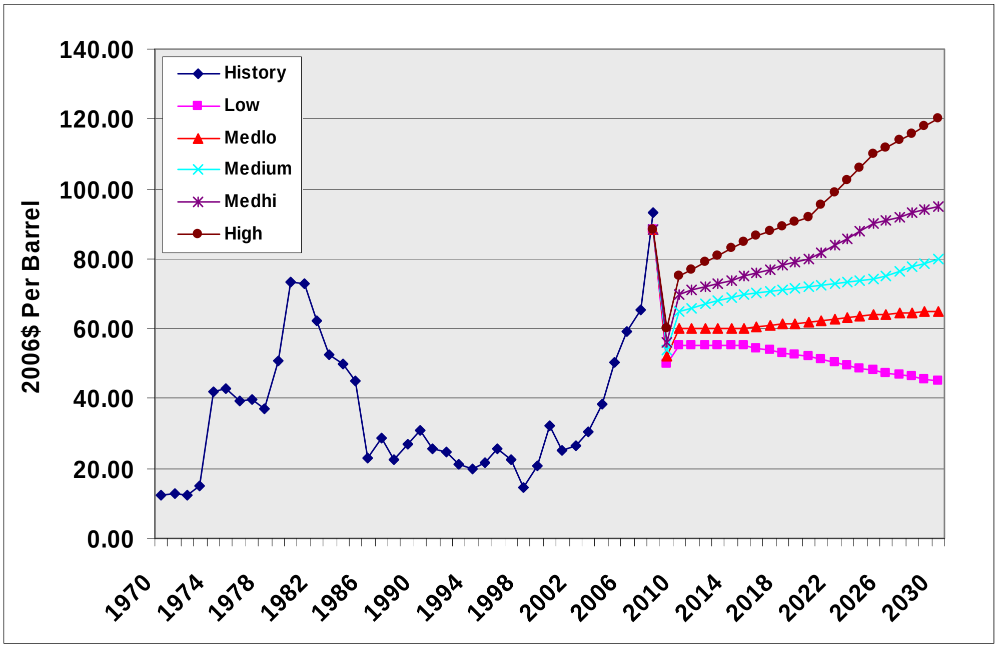
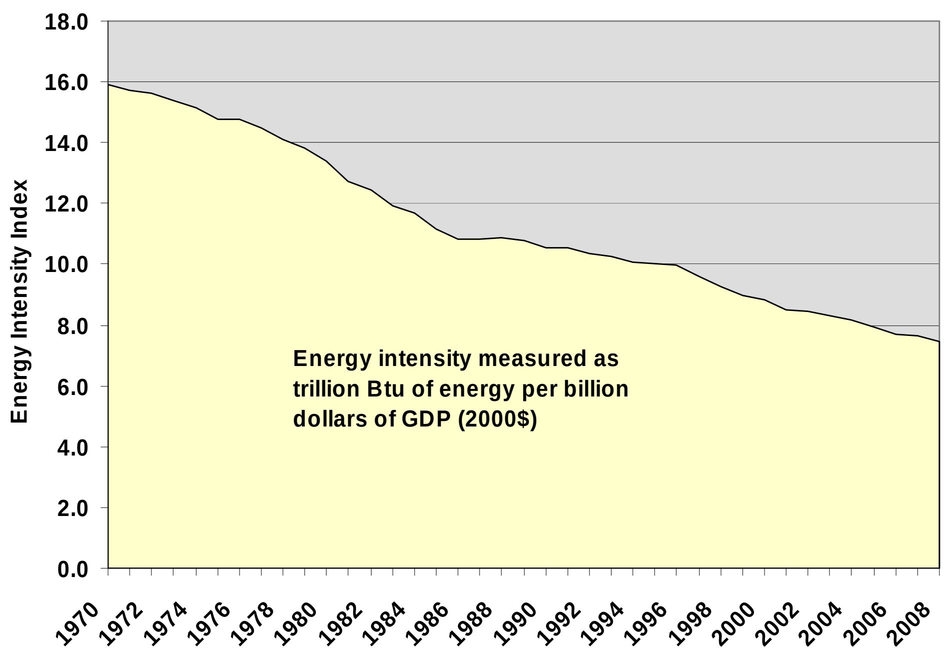



**Figure A-10: Total U.S. Energy Use per Dollar of Gross Domestic Product**




The low case is also considered unlikely from today's perspective even though it is slightly higher than prices experienced during the 1990s. This scenario might be consistent with rapid progress in efficiency and renewable resources, combined with a growing ability of the Middle East and former Soviet Union states to produce their oil resources. In addition, the low case would require substantial progress in reducing the use of carbon fuels as a result of aggressive climate change policies.

The medium-low and medium-high cases are variations around the medium forecast. In the past, the Council has considered these cases to be nearly as likely as the medium case. However, given the fact that these forecasts are being prepared in the context of a very high price period, and the historical fact that forecasts done in such time periods tend to overstate future prices, the medium-low case may be more likely than the medium-high case.

Table A-3 shows the values of the forecast range for selected years. The estimated 2008 value is based on prices through September and futures market expectations for the rest of the year.

**Table A-3: World Oil Price Forecast Range (2006 Dollar Per Barrel)**

| | Low | Medium Low | Medium | Medium High | High |
|---|---|---|---|---|---|
| **2007** | | | 65.29 | | |
| **2008** | | | 88.42 | | |
| **2010** | 55.00 | 60.00 | 65.00 | 70.00 | 75.00 |
| **2015** | 55.00 | 60.00 | 70.00 | 75.00 | 85.00 |
| **2020** | 52.00 | 62.00 | 72.00 | 80.00 | 92.00 |
| **2025** | 48.00 | 64.00 | 74.00 | 90.00 | 110.00 |
| **2030** | 45.00 | 65.00 | 80.00 | 95.00 | 120.00 |
| **Growth Rates** | | | | | |
| **2007 - 15** | -2.12% | -1.05% | 0.88% | 1.75% | 3.35% |
| **2007 - 30** | -1.60% | -0.02% | 0.89% | 1.64% | 2.68% |

As in the case of natural gas, oil commodity prices are used to estimate future oil product prices at the wholesale and retail level. The refiner wholesale prices of heavy and light oil products are based on refinery costs and a simple profit maximization calculation. Retail price forecasts are based on simple historical relationships between wholesale oil product prices (residual and distillate oils) and retail prices. These prices are shown in the appendix tables.

# COAL

## *Coal Commodity Prices*

Coal is a plentiful energy source in the United States. Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[2] 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 1.1 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 interior deposits. Western coal, especially Powder River Basin 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 sulfur dioxide emissions under the 1990 Clean Air Act Amendments that took effect on January 1, 2000. The other characteristic that distinguishes

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

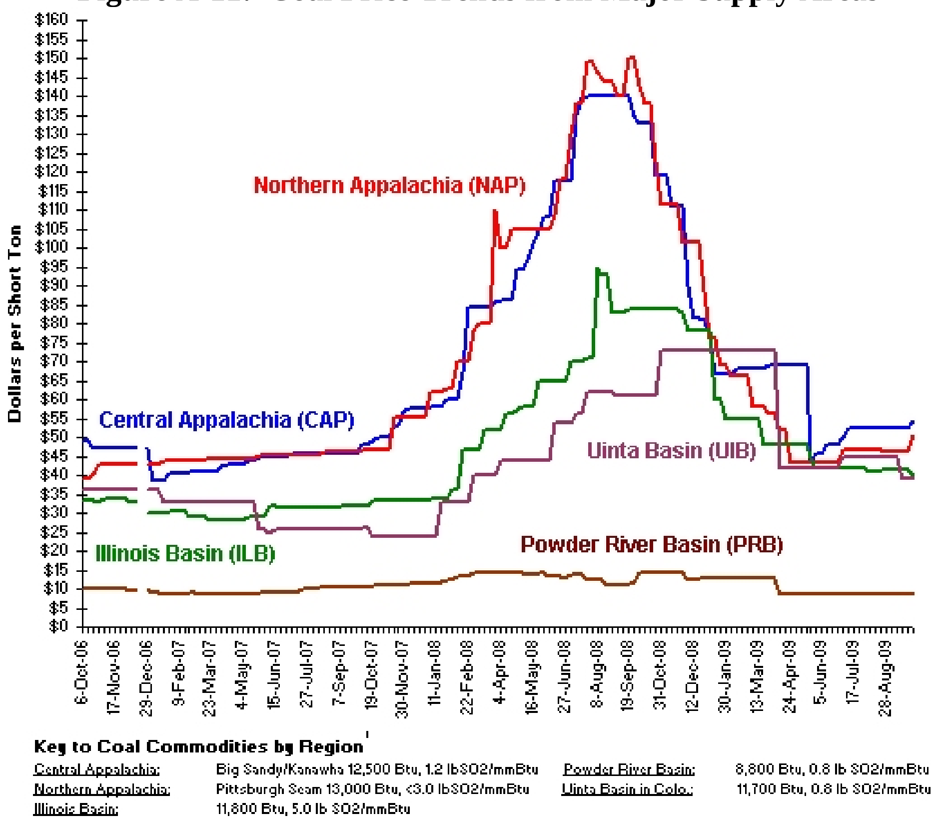
most Western coal from Eastern and interior supplies is its Btu content. Western coal is predominately sub-bituminous coal with an average heat content of about 17 million Btu's per short ton. In contrast, Appalachian and interior coal tends to be predominately higher grade bituminous coal with heat rates averaging about 24 million Btu per short ton. Another drawback of some Western coal is a relatively high arsenic content, which will require more expensive treatment for removal under stricter environmental rules.

Western coal production in 2007 was 612 million short tons, with 74 percent of that production coming from Wyoming (454 million short tons). The second largest state producer was Montana at 43 million tons. Colorado, New Mexico, North Dakota and Utah produced between 24 and 36 million short tons each, and Arizona produced about 8 million short tons.[3]

Historical productivity increases have been rapid, especially in Western coal mines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by an average of 1.6 percent per year between 1985 and 2005. Expiring higher-priced long-term contracts have also contributed to declining coal prices.

Most of the coal used in the Pacific Northwest comes from the Power River Basin in Wyoming and Montana. As noted above, the cost of Power River Basin coal is very low relative to other coal. Figure A-11 shows historical coal cost from various supply areas. Additional forecast details are shown in the appendix tables.

**Figure A-11: Coal Price Trends from Major Supply Areas**




Source: U.S. Department of Energy, Energy Information Administration

[3] U.S. Energy Information Administration, Annual Coal Report, September 2008.

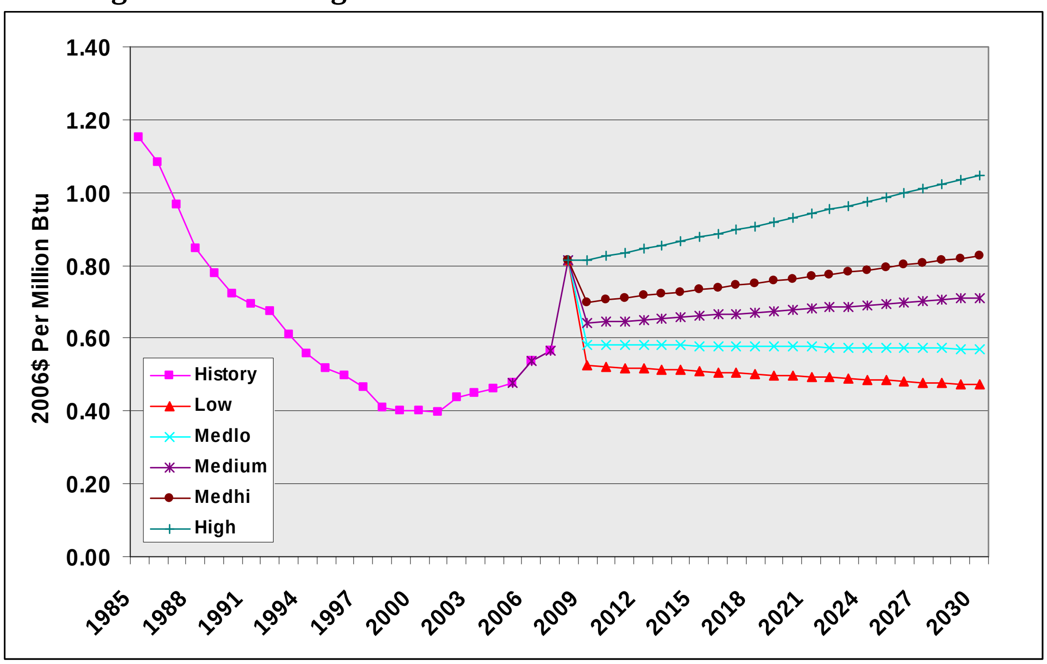
## *Coal Price Forecast*

The forecast cost of coal to the Pacific Northwest is based on projected Powder River Basin coal prices. These forecasts are simple price growth rate assumptions from 2010 to 2030 with varying degrees of recovery from recent price increases by 2010. Table A-4 demonstrates these assumptions. Figure A-12 shows the resulting forecast range.

**Table A-4: Coal Price Assumptions (2006 Dollars Per Million Btu)**

| | Low | Medium Low | Medium | Medium High | High |
|---|---|---|---|---|---|
| **2007** | | | $0.56 | | |
| **2010** | $0.52 | $0.58 | $0.64 | $0.70 | $0.83 |
| **2015** | $0.51 | $0.58 | $0.66 | $0.73 | $0.88 |
| **2020** | $0.50 | $0.58 | $0.68 | $0.76 | $0.93 |
| **2025** | $0.48 | $0.57 | $0.69 | $0.79 | $0.99 |
| **2030** | $0.47 | $0.57 | $0.71 | $0.83 | $1.05 |
| **Growth Rates** | | | | | |
| **2007-15** | -1.29% | 0.32% | 1.98% | 3.33% | 5.65% |
| **2007-30** | -0.78% | 0.05% | 1.01% | 1.67% | 2.73% |

**Figure A-12: Range of Powder River Basin Coal Price Forecasts**



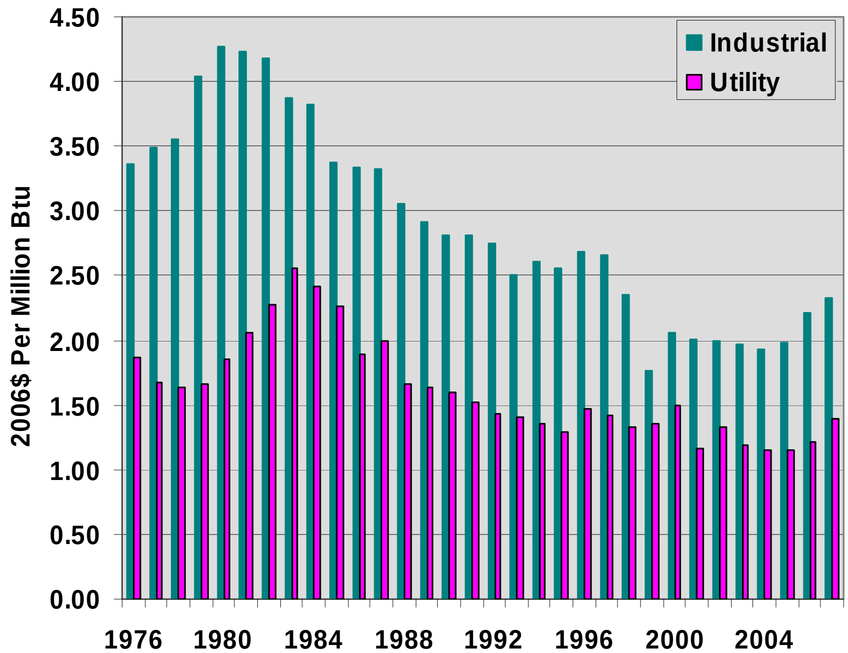

The price of coal delivered to northwest electric generators and industries is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from mine-mouth costs due to long-term coal supply contracts. Figure A-13 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 2005.[4] Coal prices increased during the late 1970s with other energy prices, but after the early 1980s declined steadily until 2000 when they increased slightly in response to increased commodity prices and increased use, both domestically and for export. On average, regional industrial coal prices decreased at an annual rate of 3 percent between 1980 and 2005. Regional utility coal prices

[4] U.S. Energy Information Administration

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 electric generating plants.

Delivered coal prices to utilities in various locations of the Northwest and West are forecast based on the commodity price forecast. These forecasts are based on a simple relationship of the distance in miles from the Power River Basin to various locations, the cost of unit train shipment of coal per ton-mile, and an adjustment of the shipment cost to reflect the forecast of changes in transportation diesel fuel, a significant factor in the shipment costs.

**Figure A-13: Utility and Industrial Coal Prices in the Pacific Northwest**



# Appendix A1: Medium Case Fuel Price Forecast Tables

**Table A1-1: Natural Gas Prices at Key Hubs and Northwest Generators**
**2006$/MMBtu**
**Medium Case**

| Year | Henry Hub Natural Gas Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
|---|---|---|---|---|---|
| 2005 | 7.95 | 6.98 | 7.08 | 7.70 | 7.58 |
| 2006 | 6.72 | 5.84 | 5.95 | 6.56 | 6.42 |
| 2007 | 6.53 | 5.67 | 5.78 | 6.38 | 6.24 |
| 2008 | 8.12 | 7.08 | 7.72 | 8.41 | 7.68 |
| 2009 | 3.95 | 3.35 | 3.94 | 4.59 | 3.91 |
| 2010 | 4.62 | 3.95 | 4.54 | 5.28 | 4.56 |
| 2011 | 4.90 | 4.20 | 4.80 | 5.61 | 4.86 |
| 2012 | 5.20 | 4.47 | 5.07 | 5.90 | 5.19 |
| 2013 | 5.52 | 4.76 | 5.36 | 6.20 | 5.48 |
| 2014 | 5.86 | 5.06 | 5.67 | 6.52 | 5.79 |
| 2015 | 6.22 | 5.38 | 6.00 | 6.85 | 6.11 |
| 2016 | 6.32 | 5.48 | 6.09 | 6.96 | 6.22 |
| 2017 | 6.43 | 5.57 | 6.19 | 7.06 | 6.32 |
| 2018 | 6.54 | 5.67 | 6.29 | 7.16 | 6.44 |
| 2019 | 6.65 | 5.77 | 6.39 | 7.27 | 6.54 |
| 2020 | 6.77 | 5.87 | 6.50 | 7.38 | 6.64 |
| 2021 | 6.93 | 6.02 | 6.64 | 7.53 | 6.79 |
| 2022 | 7.09 | 6.16 | 6.79 | 7.68 | 6.94 |
| 2023 | 7.25 | 6.31 | 6.94 | 7.83 | 7.09 |
| 2024 | 7.42 | 6.46 | 7.09 | 7.99 | 7.25 |
| 2025 | 7.60 | 6.62 | 7.25 | 8.16 | 7.41 |
| 2026 | 7.70 | 6.71 | 7.35 | 8.26 | 7.51 |
| 2027 | 7.81 | 6.81 | 7.45 | 8.36 | 7.61 |
| 2028 | 7.92 | 6.91 | 7.55 | 8.47 | 7.71 |
| 2029 | 8.03 | 7.01 | 7.65 | 8.57 | 7.82 |
| 2030 | 8.15 | 7.11 | 7.75 | 8.68 | 7.92 |

**Table A1-2: Wellhead and Retail Natural Gas Prices**
**2006$/MMBtu**
**Medium Case**

| Year | U.S. Wellhead Prices | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| | | Residential | Commercial | Industrial | Utility Average |
| 2005 | 7.36 | 12.66 | 11.16 | 8.26 | 7.64 |
| 2006 | 6.23 | 11.53 | 10.03 | 7.12 | 6.49 |
| 2007 | 6.06 | 11.36 | 9.86 | 6.95 | 6.31 |
| 2008 | 7.47 | 12.77 | 11.27 | 8.76 | 8.03 |
| 2009 | 3.70 | 9.00 | 7.50 | 4.92 | 4.22 |
| 2010 | 4.30 | 9.60 | 8.10 | 5.53 | 4.86 |
| 2011 | 4.56 | 9.86 | 8.36 | 5.79 | 5.15 |
| 2012 | 4.83 | 10.13 | 8.63 | 6.07 | 5.44 |
| 2013 | 5.12 | 10.42 | 8.92 | 6.36 | 5.74 |
| 2014 | 5.43 | 10.73 | 9.23 | 6.68 | 6.05 |
| 2015 | 5.75 | 11.05 | 9.55 | 7.01 | 6.38 |
| 2016 | 5.85 | 11.15 | 9.65 | 7.10 | 6.48 |
| 2017 | 5.95 | 11.25 | 9.75 | 7.21 | 6.58 |
| 2018 | 6.04 | 11.35 | 9.85 | 7.31 | 6.69 |
| 2019 | 6.15 | 11.45 | 9.95 | 7.41 | 6.79 |
| 2020 | 6.25 | 11.55 | 10.05 | 7.52 | 6.90 |
| 2021 | 6.39 | 11.70 | 10.19 | 7.66 | 7.04 |
| 2022 | 6.54 | 11.84 | 10.34 | 7.81 | 7.19 |
| 2023 | 6.69 | 11.99 | 10.49 | 7.96 | 7.35 |
| 2024 | 6.84 | 12.15 | 10.64 | 8.12 | 7.50 |
| 2025 | 7.00 | 12.30 | 10.80 | 8.28 | 7.66 |
| 2026 | 7.10 | 12.40 | 10.90 | 8.38 | 7.76 |
| 2027 | 7.20 | 12.50 | 11.00 | 8.48 | 7.87 |
| 2028 | 7.30 | 12.60 | 11.10 | 8.58 | 7.97 |
| 2029 | 7.40 | 12.70 | 11.20 | 8.68 | 8.07 |
| 2030 | 7.50 | 12.80 | 11.30 | 8.79 | 8.18 |

**Table A1-3: World Oil Prices and Retail Oil Product Prices**
**2006$/MMBtu**
**Medium Case**

| Year | World Oil Prices | Industrial Residual Oil Price | Industrial | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 50.40 | 6.95 | 12.55 | 12.25 | 7.22 | 12.04 | 11.90 | 14.94 | 0.00 | 11.56 |
| 2006 | 59.02 | 8.22 | 14.20 | 13.89 | 8.49 | 13.69 | 13.55 | 16.60 | 0.00 | 13.22 |
| 2007 | 65.29 | 9.15 | 15.41 | 15.08 | 9.41 | 14.90 | 14.74 | 17.80 | 0.00 | 14.42 |
| 2008 | 88.42 | 12.56 | 19.86 | 19.47 | 12.83 | 19.35 | 19.16 | 22.25 | 0.00 | 18.87 |
| 2009 | 54.00 | 7.48 | 13.24 | 12.93 | 7.75 | 12.73 | 12.59 | 15.63 | 0.00 | 12.25 |
| 2010 | 65.00 | 9.10 | 15.35 | 15.02 | 9.37 | 14.84 | 14.69 | 17.75 | 0.00 | 14.37 |
| 2011 | 65.97 | 9.25 | 15.54 | 15.21 | 9.52 | 15.03 | 14.88 | 17.93 | 0.00 | 14.55 |
| 2012 | 66.96 | 9.39 | 15.73 | 15.39 | 9.66 | 15.22 | 15.06 | 18.12 | 0.00 | 14.74 |
| 2013 | 67.96 | 9.54 | 15.92 | 15.58 | 9.81 | 15.41 | 15.25 | 18.32 | 0.00 | 14.94 |
| 2014 | 68.97 | 9.69 | 16.12 | 15.78 | 9.96 | 15.61 | 15.45 | 18.51 | 0.00 | 15.13 |
| 2015 | 70.00 | 9.84 | 16.31 | 15.97 | 10.11 | 15.80 | 15.65 | 18.71 | 0.00 | 15.33 |
| 2016 | 70.40 | 9.90 | 16.39 | 16.05 | 10.17 | 15.88 | 15.72 | 18.78 | 0.00 | 15.41 |
| 2017 | 70.79 | 9.96 | 16.47 | 16.12 | 10.23 | 15.96 | 15.80 | 18.86 | 0.00 | 15.48 |
| 2018 | 71.19 | 10.02 | 16.54 | 16.20 | 10.29 | 16.03 | 15.87 | 18.94 | 0.00 | 15.56 |
| 2019 | 71.60 | 10.08 | 16.62 | 16.27 | 10.35 | 16.11 | 15.95 | 19.01 | 0.00 | 15.64 |
| 2020 | 72.00 | 10.14 | 16.70 | 16.35 | 10.41 | 16.19 | 16.03 | 19.09 | 0.00 | 15.71 |
| 2021 | 72.40 | 10.20 | 16.77 | 16.43 | 10.46 | 16.26 | 16.10 | 19.17 | 0.00 | 15.79 |
| 2022 | 72.79 | 10.25 | 16.85 | 16.50 | 10.52 | 16.34 | 16.18 | 19.25 | 0.00 | 15.87 |
| 2023 | 73.19 | 10.31 | 16.93 | 16.58 | 10.58 | 16.42 | 16.26 | 19.32 | 0.00 | 15.94 |
| 2024 | 73.60 | 10.37 | 17.01 | 16.65 | 10.64 | 16.49 | 16.33 | 19.40 | 0.00 | 16.02 |
| 2025 | 74.00 | 10.43 | 17.08 | 16.73 | 10.70 | 16.57 | 16.41 | 19.48 | 0.00 | 16.10 |
| 2026 | 75.16 | 10.60 | 17.31 | 16.95 | 10.87 | 16.80 | 16.63 | 19.70 | 0.00 | 16.32 |
| 2027 | 76.34 | 10.78 | 17.53 | 17.18 | 11.05 | 17.02 | 16.86 | 19.93 | 0.00 | 16.55 |
| 2028 | 77.54 | 10.96 | 17.76 | 17.40 | 11.22 | 17.25 | 17.09 | 20.16 | 0.00 | 16.78 |
| 2029 | 78.76 | 11.14 | 18.00 | 17.63 | 11.40 | 17.49 | 17.32 | 20.39 | 0.00 | 17.01 |
| 2030 | 80.00 | 11.32 | 18.24 | 17.87 | 11.59 | 17.73 | 17.56 | 20.63 | 0.00 | 17.25 |

**Table A1-4: Coal Price Forecasts**
**2006$/MMBtu**
**Medium Case**

| | | | Selected Regional Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | West WA/OR | East WA/OR | Idaho | Montana | Utah | Wyoming |
| 2005 | 0.48 | 2.11 | 1.40 | 1.22 | 0.82 | 0.78 | 0.67 | 0.58 |
| 2006 | 0.54 | 2.08 | 1.43 | 1.25 | 0.87 | 0.83 | 0.72 | 0.64 |
| 2007 | 0.56 | 2.09 | 1.45 | 1.27 | 0.89 | 0.85 | 0.75 | 0.66 |
| 2008 | 0.82 | 2.44 | 1.73 | 1.55 | 1.15 | 1.11 | 1.00 | 0.92 |
| 2009 | 0.64 | 1.98 | 1.45 | 1.28 | 0.94 | 0.90 | 0.81 | 0.73 |
| 2010 | 0.64 | 2.20 | 1.54 | 1.36 | 0.97 | 0.94 | 0.83 | 0.74 |
| 2011 | 0.65 | 2.14 | 1.52 | 1.34 | 0.97 | 0.93 | 0.83 | 0.74 |
| 2012 | 0.65 | 2.15 | 1.52 | 1.34 | 0.97 | 0.93 | 0.83 | 0.75 |
| 2013 | 0.65 | 2.15 | 1.52 | 1.35 | 0.97 | 0.94 | 0.83 | 0.75 |
| 2014 | 0.66 | 2.15 | 1.53 | 1.35 | 0.98 | 0.94 | 0.84 | 0.75 |
| 2015 | 0.66 | 2.16 | 1.53 | 1.35 | 0.98 | 0.94 | 0.84 | 0.76 |
| 2016 | 0.66 | 2.16 | 1.53 | 1.36 | 0.98 | 0.95 | 0.84 | 0.76 |
| 2017 | 0.67 | 2.16 | 1.53 | 1.36 | 0.99 | 0.95 | 0.84 | 0.76 |
| 2018 | 0.67 | 2.16 | 1.54 | 1.36 | 0.99 | 0.95 | 0.85 | 0.77 |
| 2019 | 0.67 | 2.17 | 1.54 | 1.37 | 0.99 | 0.96 | 0.85 | 0.77 |
| 2020 | 0.68 | 2.17 | 1.54 | 1.37 | 1.00 | 0.96 | 0.86 | 0.77 |
| 2021 | 0.68 | 2.17 | 1.55 | 1.37 | 1.00 | 0.96 | 0.86 | 0.78 |
| 2022 | 0.68 | 2.18 | 1.55 | 1.38 | 1.00 | 0.97 | 0.86 | 0.78 |
| 2023 | 0.69 | 2.18 | 1.55 | 1.38 | 1.01 | 0.97 | 0.87 | 0.78 |
| 2024 | 0.69 | 2.19 | 1.56 | 1.38 | 1.01 | 0.97 | 0.87 | 0.79 |
| 2025 | 0.69 | 2.19 | 1.56 | 1.39 | 1.01 | 0.98 | 0.87 | 0.79 |
| 2026 | 0.70 | 2.20 | 1.57 | 1.39 | 1.02 | 0.98 | 0.88 | 0.79 |
| 2027 | 0.70 | 2.20 | 1.57 | 1.40 | 1.02 | 0.98 | 0.88 | 0.80 |
| 2028 | 0.70 | 2.20 | 1.57 | 1.40 | 1.02 | 0.99 | 0.88 | 0.80 |
| 2029 | 0.71 | 2.21 | 1.58 | 1.40 | 1.03 | 0.99 | 0.89 | 0.80 |
| 2030 | 0.71 | 2.21 | 1.58 | 1.41 | 1.03 | 0.99 | 0.89 | 0.81 |

# Appendix A2: Low Case Fuel Price Forecast Tables

**Table A2-1: Natural Gas Prices at Key Hubs and Northwest Generators**
**2006$/MMBtu**
**Low Case**

| Year | Henry Hub Natural Gas Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
|---|---|---|---|---|---|
| 2005 | 7.95 | 6.98 | 7.08 | 7.70 | 7.58 |
| 2006 | 6.72 | 5.84 | 5.95 | 6.56 | 6.42 |
| 2007 | 6.53 | 5.67 | 5.78 | 6.38 | 6.24 |
| 2008 | 8.12 | 7.08 | 7.72 | 8.41 | 7.68 |
| 2009 | 3.51 | 2.96 | 3.53 | 4.18 | 3.51 |
| 2010 | 4.01 | 3.40 | 3.99 | 4.71 | 4.00 |
| 2011 | 4.06 | 3.45 | 4.03 | 4.83 | 4.09 |
| 2012 | 4.12 | 3.50 | 4.08 | 4.90 | 4.20 |
| 2013 | 4.17 | 3.55 | 4.13 | 4.95 | 4.25 |
| 2014 | 4.23 | 3.60 | 4.18 | 5.00 | 4.30 |
| 2015 | 4.29 | 3.65 | 4.24 | 5.05 | 4.35 |
| 2016 | 4.34 | 3.70 | 4.29 | 5.10 | 4.41 |
| 2017 | 4.39 | 3.75 | 4.34 | 5.15 | 4.46 |
| 2018 | 4.45 | 3.80 | 4.39 | 5.20 | 4.53 |
| 2019 | 4.50 | 3.85 | 4.44 | 5.25 | 4.58 |
| 2020 | 4.56 | 3.90 | 4.49 | 5.30 | 4.63 |
| 2021 | 4.58 | 3.92 | 4.51 | 5.32 | 4.65 |
| 2022 | 4.61 | 3.94 | 4.53 | 5.34 | 4.67 |
| 2023 | 4.63 | 3.96 | 4.55 | 5.36 | 4.69 |
| 2024 | 4.65 | 3.98 | 4.57 | 5.38 | 4.71 |
| 2025 | 4.67 | 4.00 | 4.59 | 5.40 | 4.73 |
| 2026 | 4.70 | 4.03 | 4.62 | 5.43 | 4.76 |
| 2027 | 4.74 | 4.05 | 4.65 | 5.46 | 4.78 |
| 2028 | 4.77 | 4.08 | 4.68 | 5.49 | 4.81 |
| 2029 | 4.80 | 4.11 | 4.71 | 5.52 | 4.84 |
| 2030 | 4.84 | 4.14 | 4.74 | 5.55 | 4.87 |

**Table A2-2: Wellhead and Retail Natural Gas Prices**
**2006$/MMBtu**
**Low Case**

| Year | U.S. Wellhead Prices | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| | | Residential | Commercial | Industrial | Utility Average |
| 2005 | 7.36 | 12.66 | 11.16 | 8.26 | 7.64 |
| 2006 | 6.23 | 11.53 | 10.03 | 7.12 | 6.49 |
| 2007 | 6.06 | 11.36 | 9.86 | 6.95 | 6.31 |
| 2008 | 7.47 | 12.77 | 11.27 | 8.76 | 8.03 |
| 2009 | 3.30 | 8.60 | 7.10 | 4.51 | 3.81 |
| 2010 | 3.75 | 9.05 | 7.55 | 4.97 | 4.30 |
| 2011 | 3.80 | 9.10 | 7.60 | 5.02 | 4.38 |
| 2012 | 3.85 | 9.15 | 7.65 | 5.07 | 4.44 |
| 2013 | 3.90 | 9.20 | 7.70 | 5.12 | 4.49 |
| 2014 | 3.95 | 9.25 | 7.75 | 5.17 | 4.55 |
| 2015 | 4.00 | 9.30 | 7.80 | 5.23 | 4.60 |
| 2016 | 4.05 | 9.35 | 7.85 | 5.28 | 4.65 |
| 2017 | 4.10 | 9.40 | 7.90 | 5.33 | 4.70 |
| 2018 | 4.15 | 9.45 | 7.95 | 5.38 | 4.75 |
| 2019 | 4.20 | 9.50 | 8.00 | 5.43 | 4.81 |
| 2020 | 4.25 | 9.55 | 8.05 | 5.48 | 4.86 |
| 2021 | 4.27 | 9.57 | 8.07 | 5.50 | 4.88 |
| 2022 | 4.29 | 9.59 | 8.09 | 5.52 | 4.90 |
| 2023 | 4.31 | 9.61 | 8.11 | 5.54 | 4.92 |
| 2024 | 4.33 | 9.63 | 8.13 | 5.56 | 4.94 |
| 2025 | 4.35 | 9.65 | 8.15 | 5.58 | 4.96 |
| 2026 | 4.38 | 9.68 | 8.18 | 5.61 | 4.99 |
| 2027 | 4.41 | 9.71 | 8.21 | 5.64 | 5.02 |
| 2028 | 4.44 | 9.74 | 8.24 | 5.67 | 5.05 |
| 2029 | 4.47 | 9.77 | 8.27 | 5.70 | 5.08 |
| 2030 | 4.50 | 9.80 | 8.30 | 5.73 | 5.11 |

**Table A2-3: World Oil Prices and Retail Oil Products Prices**
**2006$/MMBtu**
**Low Case**

| Year | World Oil Prices | Industrial Residual Oil Price | Industrial | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 50.40 | 6.95 | 12.55 | 12.25 | 7.22 | 12.04 | 11.90 | 14.94 | 0.00 | 11.56 |
| 2006 | 59.02 | 8.22 | 14.20 | 13.89 | 8.49 | 13.69 | 13.55 | 16.60 | 0.00 | 13.22 |
| 2007 | 65.29 | 9.15 | 15.41 | 15.08 | 9.41 | 14.90 | 14.74 | 17.80 | 0.00 | 14.42 |
| 2008 | 0.00 | -0.50 | 2.85 | 2.68 | -0.23 | 2.34 | 2.27 | 5.25 | 0.00 | 1.87 |
| 2009 | 50.00 | 6.89 | 12.47 | 12.17 | 7.16 | 11.96 | 11.82 | 14.86 | 0.00 | 11.48 |
| 2010 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2011 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2012 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2013 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2014 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2015 | 55.00 | 7.63 | 13.43 | 13.12 | 7.90 | 12.92 | 12.78 | 15.82 | 0.00 | 12.45 |
| 2016 | 54.39 | 7.54 | 13.31 | 13.01 | 7.80 | 12.80 | 12.66 | 15.71 | 0.00 | 12.33 |
| 2017 | 53.78 | 7.45 | 13.20 | 12.89 | 7.71 | 12.68 | 12.55 | 15.59 | 0.00 | 12.21 |
| 2018 | 53.18 | 7.36 | 13.08 | 12.78 | 7.63 | 12.57 | 12.43 | 15.47 | 0.00 | 12.10 |
| 2019 | 52.59 | 7.27 | 12.97 | 12.66 | 7.54 | 12.46 | 12.32 | 15.36 | 0.00 | 11.98 |
| 2020 | 52.00 | 7.18 | 12.85 | 12.55 | 7.45 | 12.34 | 12.21 | 15.25 | 0.00 | 11.87 |
| 2021 | 51.17 | 7.06 | 12.69 | 12.40 | 7.33 | 12.18 | 12.05 | 15.09 | 0.00 | 11.71 |
| 2022 | 50.36 | 6.94 | 12.54 | 12.24 | 7.21 | 12.03 | 11.89 | 14.93 | 0.00 | 11.55 |
| 2023 | 49.56 | 6.82 | 12.38 | 12.09 | 7.09 | 11.87 | 11.74 | 14.78 | 0.00 | 11.40 |
| 2024 | 48.77 | 6.71 | 12.23 | 11.94 | 6.98 | 11.72 | 11.59 | 14.63 | 0.00 | 11.25 |
| 2025 | 48.00 | 6.59 | 12.08 | 11.79 | 6.86 | 11.57 | 11.44 | 14.48 | 0.00 | 11.10 |
| 2026 | 47.38 | 6.50 | 11.97 | 11.68 | 6.77 | 11.46 | 11.32 | 14.36 | 0.00 | 10.98 |
| 2027 | 46.78 | 6.41 | 11.85 | 11.56 | 6.68 | 11.34 | 11.21 | 14.24 | 0.00 | 10.86 |
| 2028 | 46.18 | 6.32 | 11.73 | 11.45 | 6.59 | 11.22 | 11.09 | 14.13 | 0.00 | 10.75 |
| 2029 | 45.58 | 6.24 | 11.62 | 11.33 | 6.50 | 11.11 | 10.98 | 14.01 | 0.00 | 10.64 |
| 2030 | 45.00 | 6.15 | 11.51 | 11.22 | 6.42 | 11.00 | 10.87 | 13.90 | 0.00 | 10.52 |

**Table A2-4: Coal Price Forecasts**
**2006$/MMBtu**
**Low Case**

| | | | Selected Regional Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | West WA/OR | East WA/OR | Idaho | Montana | Utah | Wyoming |
| 2005 | 0.48 | 2.11 | 1.40 | 1.22 | 0.82 | 0.78 | 0.67 | 0.58 |
| 2006 | 0.54 | 2.08 | 1.43 | 1.25 | 0.87 | 0.83 | 0.72 | 0.64 |
| 2007 | 0.56 | 2.09 | 1.45 | 1.27 | 0.89 | 0.85 | 0.75 | 0.66 |
| 2008 | 0.82 | 1.92 | 1.54 | 1.39 | 1.08 | 1.05 | 0.96 | 0.89 |
| 2009 | 0.52 | 2.78 | 1.72 | 1.48 | 0.96 | 0.91 | 0.77 | 0.66 |
| 2010 | 0.52 | 2.04 | 1.40 | 1.22 | 0.85 | 0.81 | 0.70 | 0.62 |
| 2011 | 0.52 | 2.01 | 1.39 | 1.21 | 0.84 | 0.80 | 0.70 | 0.61 |
| 2012 | 0.52 | 2.01 | 1.38 | 1.21 | 0.84 | 0.80 | 0.69 | 0.61 |
| 2013 | 0.51 | 2.01 | 1.38 | 1.21 | 0.83 | 0.80 | 0.69 | 0.61 |
| 2014 | 0.51 | 2.00 | 1.38 | 1.20 | 0.83 | 0.79 | 0.69 | 0.61 |
| 2015 | 0.51 | 2.00 | 1.38 | 1.20 | 0.83 | 0.79 | 0.69 | 0.60 |
| 2016 | 0.51 | 2.00 | 1.37 | 1.20 | 0.82 | 0.79 | 0.68 | 0.60 |
| 2017 | 0.50 | 1.99 | 1.37 | 1.19 | 0.82 | 0.79 | 0.68 | 0.60 |
| 2018 | 0.50 | 1.99 | 1.37 | 1.19 | 0.82 | 0.78 | 0.68 | 0.60 |
| 2019 | 0.50 | 1.99 | 1.36 | 1.19 | 0.82 | 0.78 | 0.68 | 0.59 |
| 2020 | 0.50 | 1.99 | 1.36 | 1.19 | 0.81 | 0.78 | 0.67 | 0.59 |
| 2021 | 0.49 | 1.98 | 1.36 | 1.18 | 0.81 | 0.78 | 0.67 | 0.59 |
| 2022 | 0.49 | 1.98 | 1.36 | 1.18 | 0.81 | 0.77 | 0.67 | 0.59 |
| 2023 | 0.49 | 1.98 | 1.35 | 1.18 | 0.81 | 0.77 | 0.67 | 0.58 |
| 2024 | 0.49 | 1.97 | 1.35 | 1.18 | 0.80 | 0.77 | 0.66 | 0.58 |
| 2025 | 0.48 | 1.97 | 1.35 | 1.17 | 0.80 | 0.77 | 0.66 | 0.58 |
| 2026 | 0.48 | 1.97 | 1.35 | 1.17 | 0.80 | 0.76 | 0.66 | 0.58 |
| 2027 | 0.48 | 1.97 | 1.34 | 1.17 | 0.80 | 0.76 | 0.66 | 0.57 |
| 2028 | 0.48 | 1.97 | 1.34 | 1.17 | 0.80 | 0.76 | 0.65 | 0.57 |
| 2029 | 0.47 | 1.96 | 1.34 | 1.17 | 0.79 | 0.76 | 0.65 | 0.57 |
| 2030 | 0.47 | 1.96 | 1.34 | 1.16 | 0.79 | 0.75 | 0.65 | 0.57 |

# Appendix A3: Medium-Low Case Fuel Price Forecast Tables

**Table A3-1: Natural Gas Prices at Key Hubs and Northwest Generators**
**2006$/MMBtu**
**Medlo Case**

| Year | Henry Hub Natural Gas Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
|---|---|---|---|---|---|
| 2005 | 7.95 | 6.98 | 7.08 | 7.70 | 7.58 |
| 2006 | 6.72 | 5.84 | 5.95 | 6.56 | 6.42 |
| 2007 | 6.53 | 5.67 | 5.78 | 6.38 | 6.24 |
| 2008 | 8.12 | 7.08 | 7.72 | 8.41 | 7.68 |
| 2009 | 3.73 | 3.16 | 3.73 | 4.39 | 3.71 |
| 2010 | 4.29 | 3.65 | 4.24 | 4.97 | 4.25 |
| 2011 | 4.45 | 3.80 | 4.39 | 5.19 | 4.44 |
| 2012 | 4.62 | 3.95 | 4.54 | 5.36 | 4.65 |
| 2013 | 4.80 | 4.11 | 4.70 | 5.53 | 4.81 |
| 2014 | 4.98 | 4.27 | 4.87 | 5.70 | 4.98 |
| 2015 | 5.17 | 4.44 | 5.04 | 5.88 | 5.16 |
| 2016 | 5.29 | 4.55 | 5.16 | 5.99 | 5.28 |
| 2017 | 5.42 | 4.67 | 5.27 | 6.11 | 5.40 |
| 2018 | 5.56 | 4.79 | 5.39 | 6.24 | 5.54 |
| 2019 | 5.69 | 4.91 | 5.52 | 6.36 | 5.66 |
| 2020 | 5.83 | 5.03 | 5.64 | 6.49 | 5.79 |
| 2021 | 5.92 | 5.11 | 5.72 | 6.57 | 5.87 |
| 2022 | 6.00 | 5.19 | 5.80 | 6.66 | 5.95 |
| 2023 | 6.09 | 5.27 | 5.88 | 6.74 | 6.03 |
| 2024 | 6.18 | 5.35 | 5.96 | 6.82 | 6.11 |
| 2025 | 6.27 | 5.43 | 6.05 | 6.91 | 6.19 |
| 2026 | 6.32 | 5.47 | 6.09 | 6.95 | 6.23 |
| 2027 | 6.36 | 5.51 | 6.12 | 6.99 | 6.27 |
| 2028 | 6.40 | 5.55 | 6.17 | 7.03 | 6.32 |
| 2029 | 6.45 | 5.59 | 6.21 | 7.07 | 6.36 |
| 2030 | 6.49 | 5.63 | 6.25 | 7.12 | 6.40 |

**Table A3-2: Wellhead and Retail Natural Gas Prices**
**2006$/MMBtu**
**Medlo Case**

| Year | U.S. Wellhead Prices | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| | | Residential | Commercial | Industrial | Utility Average |
| 2005 | 7.36 | 12.66 | 11.16 | 8.26 | 7.64 |
| 2006 | 6.23 | 11.53 | 10.03 | 7.12 | 6.49 |
| 2007 | 6.06 | 11.36 | 9.86 | 6.95 | 6.31 |
| 2008 | 7.47 | 12.77 | 11.27 | 8.76 | 8.03 |
| 2009 | 3.50 | 8.80 | 7.30 | 4.72 | 4.02 |
| 2010 | 4.00 | 9.30 | 7.80 | 5.23 | 4.55 |
| 2011 | 4.15 | 9.45 | 7.95 | 5.38 | 4.73 |
| 2012 | 4.30 | 9.61 | 8.10 | 5.53 | 4.91 |
| 2013 | 4.46 | 9.77 | 8.26 | 5.70 | 5.07 |
| 2014 | 4.63 | 9.93 | 8.43 | 5.86 | 5.24 |
| 2015 | 4.80 | 10.10 | 8.60 | 6.04 | 5.41 |
| 2016 | 4.91 | 10.22 | 8.71 | 6.16 | 5.53 |
| 2017 | 5.03 | 10.34 | 8.83 | 6.28 | 5.65 |
| 2018 | 5.15 | 10.46 | 8.95 | 6.40 | 5.78 |
| 2019 | 5.27 | 10.58 | 9.07 | 6.52 | 5.90 |
| 2020 | 5.40 | 10.70 | 9.20 | 6.65 | 6.03 |
| 2021 | 5.48 | 10.78 | 9.28 | 6.73 | 6.11 |
| 2022 | 5.56 | 10.86 | 9.36 | 6.81 | 6.19 |
| 2023 | 5.64 | 10.94 | 9.44 | 6.89 | 6.27 |
| 2024 | 5.72 | 11.02 | 9.52 | 6.97 | 6.35 |
| 2025 | 5.80 | 11.10 | 9.60 | 7.06 | 6.44 |
| 2026 | 5.84 | 11.14 | 9.64 | 7.10 | 6.48 |
| 2027 | 5.88 | 11.18 | 9.68 | 7.14 | 6.52 |
| 2028 | 5.92 | 11.22 | 9.72 | 7.18 | 6.56 |
| 2029 | 5.96 | 11.26 | 9.76 | 7.22 | 6.60 |
| 2030 | 6.00 | 11.30 | 9.80 | 7.26 | 6.64 |

**Table A3-3: World Oil Prices and Retail Oil Product Prices**
**2006$/MMBtu**
**Medlo Case**

| Year | World Oil Prices | Industrial Residual Oil Price | Industrial | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 50.40 | 6.95 | 12.55 | 12.25 | 7.22 | 12.04 | 11.90 | 14.94 | 0.00 | 11.56 |
| 2006 | 59.02 | 8.22 | 14.20 | 13.89 | 8.49 | 13.69 | 13.55 | 16.60 | 0.00 | 13.22 |
| 2007 | 65.29 | 9.15 | 15.41 | 15.08 | 9.41 | 14.90 | 14.74 | 17.80 | 0.00 | 14.42 |
| 2008 | 0.00 | -0.50 | 2.85 | 2.68 | -0.23 | 2.34 | 2.27 | 5.25 | 0.00 | 1.87 |
| 2009 | 52.00 | 7.18 | 12.85 | 12.55 | 7.45 | 12.34 | 12.21 | 15.25 | 0.00 | 11.87 |
| 2010 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2011 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2012 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2013 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2014 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2015 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2016 | 60.39 | 8.42 | 14.47 | 14.15 | 8.69 | 13.96 | 13.81 | 16.86 | 0.00 | 13.48 |
| 2017 | 60.79 | 8.48 | 14.54 | 14.22 | 8.75 | 14.03 | 13.89 | 16.94 | 0.00 | 13.56 |
| 2018 | 61.19 | 8.54 | 14.62 | 14.30 | 8.81 | 14.11 | 13.96 | 17.01 | 0.00 | 13.64 |
| 2019 | 61.59 | 8.60 | 14.70 | 14.37 | 8.87 | 14.19 | 14.04 | 17.09 | 0.00 | 13.71 |
| 2020 | 62.00 | 8.66 | 14.78 | 14.45 | 8.93 | 14.27 | 14.12 | 17.17 | 0.00 | 13.79 |
| 2021 | 62.39 | 8.72 | 14.85 | 14.53 | 8.99 | 14.34 | 14.19 | 17.25 | 0.00 | 13.87 |
| 2022 | 62.79 | 8.78 | 14.93 | 14.60 | 9.05 | 14.42 | 14.27 | 17.32 | 0.00 | 13.94 |
| 2023 | 63.19 | 8.84 | 15.01 | 14.68 | 9.10 | 14.49 | 14.34 | 17.40 | 0.00 | 14.02 |
| 2024 | 63.59 | 8.90 | 15.08 | 14.75 | 9.16 | 14.57 | 14.42 | 17.48 | 0.00 | 14.10 |
| 2025 | 64.00 | 8.96 | 15.16 | 14.83 | 9.22 | 14.65 | 14.50 | 17.55 | 0.00 | 14.18 |
| 2026 | 64.20 | 8.99 | 15.20 | 14.87 | 9.25 | 14.69 | 14.54 | 17.59 | 0.00 | 14.21 |
| 2027 | 64.40 | 9.01 | 15.24 | 14.91 | 9.28 | 14.73 | 14.58 | 17.63 | 0.00 | 14.25 |
| 2028 | 64.60 | 9.04 | 15.28 | 14.94 | 9.31 | 14.76 | 14.61 | 17.67 | 0.00 | 14.29 |
| 2029 | 64.80 | 9.07 | 15.31 | 14.98 | 9.34 | 14.80 | 14.65 | 17.71 | 0.00 | 14.33 |
| 2030 | 65.00 | 9.10 | 15.35 | 15.02 | 9.37 | 14.84 | 14.69 | 17.75 | 0.00 | 14.37 |

**Table A3-4: Coal Price Forecasts**
**2006$/MMBtu**
**Medlo Case**

| | | | Selected Regional Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | West WA/OR | East WA/OR | Idaho | Montana | Utah | Wyoming |
| 2005 | 0.48 | 2.11 | 1.40 | 1.22 | 0.82 | 0.78 | 0.67 | 0.58 |
| 2006 | 0.54 | 2.08 | 1.43 | 1.25 | 0.87 | 0.83 | 0.72 | 0.64 |
| 2007 | 0.56 | 2.09 | 1.45 | 1.27 | 0.89 | 0.85 | 0.75 | 0.66 |
| 2008 | 0.82 | 1.92 | 1.54 | 1.39 | 1.08 | 1.05 | 0.96 | 0.89 |
| 2009 | 0.58 | 2.89 | 1.79 | 1.55 | 1.03 | 0.98 | 0.83 | 0.71 |
| 2010 | 0.58 | 2.12 | 1.47 | 1.29 | 0.91 | 0.87 | 0.76 | 0.68 |
| 2011 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.68 |
| 2012 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.68 |
| 2013 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.68 |
| 2014 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.67 |
| 2015 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.67 |
| 2016 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.67 |
| 2017 | 0.58 | 2.07 | 1.45 | 1.27 | 0.90 | 0.86 | 0.76 | 0.67 |
| 2018 | 0.58 | 2.07 | 1.44 | 1.27 | 0.90 | 0.86 | 0.76 | 0.67 |
| 2019 | 0.58 | 2.07 | 1.44 | 1.27 | 0.90 | 0.86 | 0.75 | 0.67 |
| 2020 | 0.58 | 2.07 | 1.44 | 1.27 | 0.90 | 0.86 | 0.75 | 0.67 |
| 2021 | 0.58 | 2.07 | 1.44 | 1.27 | 0.90 | 0.86 | 0.75 | 0.67 |
| 2022 | 0.58 | 2.07 | 1.44 | 1.27 | 0.89 | 0.86 | 0.75 | 0.67 |
| 2023 | 0.57 | 2.07 | 1.44 | 1.27 | 0.89 | 0.86 | 0.75 | 0.67 |
| 2024 | 0.57 | 2.07 | 1.44 | 1.27 | 0.89 | 0.86 | 0.75 | 0.67 |
| 2025 | 0.57 | 2.07 | 1.44 | 1.27 | 0.89 | 0.86 | 0.75 | 0.67 |
| 2026 | 0.57 | 2.07 | 1.44 | 1.27 | 0.89 | 0.85 | 0.75 | 0.67 |
| 2027 | 0.57 | 2.07 | 1.44 | 1.26 | 0.89 | 0.85 | 0.75 | 0.67 |
| 2028 | 0.57 | 2.06 | 1.44 | 1.26 | 0.89 | 0.85 | 0.75 | 0.67 |
| 2029 | 0.57 | 2.06 | 1.44 | 1.26 | 0.89 | 0.85 | 0.75 | 0.67 |
| 2030 | 0.57 | 2.06 | 1.44 | 1.26 | 0.89 | 0.85 | 0.75 | 0.67 |

# Appendix A4: Medium-High Case Fuel Price Forecast Tables

**Table A4-1: Natural Gas Prices at Key Hubs and Northwest Generators**
**2006$/MMBtu**
**Medhi Case**

| Year | Henry Hub Natural Gas Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
|---|---|---|---|---|---|
| 2005 | 7.95 | 6.98 | 7.08 | 7.70 | 7.58 |
| 2006 | 6.72 | 5.84 | 5.95 | 6.56 | 6.42 |
| 2007 | 6.53 | 5.67 | 5.78 | 6.38 | 6.24 |
| 2008 | 8.12 | 7.08 | 7.72 | 8.41 | 7.68 |
| 2009 | 4.06 | 3.45 | 4.04 | 4.70 | 4.01 |
| 2010 | 4.95 | 4.24 | 4.84 | 5.59 | 4.86 |
| 2011 | 5.34 | 4.60 | 5.20 | 6.02 | 5.26 |
| 2012 | 5.77 | 4.98 | 5.59 | 6.43 | 5.71 |
| 2013 | 6.23 | 5.39 | 6.01 | 6.87 | 6.13 |
| 2014 | 6.73 | 5.84 | 6.46 | 7.33 | 6.58 |
| 2015 | 7.27 | 6.32 | 6.95 | 7.83 | 7.07 |
| 2016 | 7.38 | 6.42 | 7.06 | 7.95 | 7.19 |
| 2017 | 7.50 | 6.53 | 7.17 | 8.06 | 7.30 |
| 2018 | 7.62 | 6.64 | 7.28 | 8.18 | 7.42 |
| 2019 | 7.75 | 6.75 | 7.39 | 8.29 | 7.54 |
| 2020 | 7.87 | 6.86 | 7.50 | 8.41 | 7.65 |
| 2021 | 8.00 | 6.98 | 7.62 | 8.54 | 7.77 |
| 2022 | 8.13 | 7.09 | 7.74 | 8.66 | 7.89 |
| 2023 | 8.26 | 7.21 | 7.86 | 8.79 | 8.02 |
| 2024 | 8.40 | 7.33 | 7.98 | 8.92 | 8.14 |
| 2025 | 8.53 | 7.46 | 8.11 | 9.05 | 8.27 |
| 2026 | 8.67 | 7.58 | 8.23 | 9.18 | 8.40 |
| 2027 | 8.81 | 7.71 | 8.36 | 9.32 | 8.53 |
| 2028 | 8.96 | 7.84 | 8.49 | 9.45 | 8.67 |
| 2029 | 9.10 | 7.97 | 8.62 | 9.59 | 8.81 |
| 2030 | 9.25 | 8.10 | 8.76 | 9.73 | 8.94 |

**Table A4-2: Wellhead and Retail Natural Gas Prices**
**2006$/MMBtu**
**Medhi Case**

| Year | U.S. Wellhead Prices | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| | | Residential | Commercial | Industrial | Utility Average |
| 2005 | 7.36 | 12.66 | 11.16 | 8.26 | 7.64 |
| 2006 | 6.23 | 11.53 | 10.03 | 7.12 | 6.49 |
| 2007 | 6.06 | 11.36 | 9.86 | 6.95 | 6.31 |
| 2008 | 7.47 | 12.77 | 11.27 | 8.76 | 8.03 |
| 2009 | 3.80 | 9.10 | 7.60 | 5.02 | 4.32 |
| 2010 | 4.60 | 9.90 | 8.40 | 5.84 | 5.16 |
| 2011 | 4.96 | 10.26 | 8.76 | 6.20 | 5.56 |
| 2012 | 5.35 | 10.65 | 9.15 | 6.60 | 5.97 |
| 2013 | 5.76 | 11.07 | 9.56 | 7.02 | 6.39 |
| 2014 | 6.21 | 11.52 | 10.01 | 7.48 | 6.85 |
| 2015 | 6.70 | 12.00 | 10.50 | 7.97 | 7.35 |
| 2016 | 6.81 | 12.11 | 10.61 | 8.08 | 7.46 |
| 2017 | 6.91 | 12.22 | 10.72 | 8.19 | 7.57 |
| 2018 | 7.02 | 12.33 | 10.83 | 8.30 | 7.69 |
| 2019 | 7.14 | 12.44 | 10.94 | 8.42 | 7.80 |
| 2020 | 7.25 | 12.55 | 11.05 | 8.53 | 7.92 |
| 2021 | 7.37 | 12.67 | 11.17 | 8.65 | 8.04 |
| 2022 | 7.48 | 12.79 | 11.28 | 8.77 | 8.16 |
| 2023 | 7.60 | 12.91 | 11.40 | 8.89 | 8.28 |
| 2024 | 7.73 | 13.03 | 11.53 | 9.02 | 8.41 |
| 2025 | 7.85 | 13.15 | 11.65 | 9.14 | 8.53 |
| 2026 | 7.98 | 13.28 | 11.78 | 9.27 | 8.66 |
| 2027 | 8.10 | 13.41 | 11.90 | 9.40 | 8.80 |
| 2028 | 8.23 | 13.54 | 12.03 | 9.53 | 8.93 |
| 2029 | 8.37 | 13.67 | 12.17 | 9.67 | 9.07 |
| 2030 | 8.50 | 13.80 | 12.30 | 9.81 | 9.20 |

**Table A4-3: World Oil Prices and Retail Oil Product Prices**
**2006$/MMBtu**
**Medhi Case**

| Year | World Oil Prices | Industrial Residual Oil Price | Industrial | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 50.40 | 6.95 | 12.55 | 12.25 | 7.22 | 12.04 | 11.90 | 14.94 | 0.00 | 11.56 |
| 2006 | 59.02 | 8.22 | 14.20 | 13.89 | 8.49 | 13.69 | 13.55 | 16.60 | 0.00 | 13.22 |
| 2007 | 65.29 | 9.15 | 15.41 | 15.08 | 9.41 | 14.90 | 14.74 | 17.80 | 0.00 | 14.42 |
| 2008 | 0.00 | -0.50 | 2.85 | 2.68 | -0.23 | 2.34 | 2.27 | 5.25 | 0.00 | 1.87 |
| 2009 | 56.00 | 7.77 | 13.62 | 13.31 | 8.04 | 13.11 | 12.97 | 16.02 | 0.00 | 12.64 |
| 2010 | 70.00 | 9.84 | 16.31 | 15.97 | 10.11 | 15.80 | 15.65 | 18.71 | 0.00 | 15.33 |
| 2011 | 70.97 | 9.99 | 16.50 | 16.16 | 10.25 | 15.99 | 15.83 | 18.90 | 0.00 | 15.52 |
| 2012 | 71.96 | 10.13 | 16.69 | 16.34 | 10.40 | 16.18 | 16.02 | 19.08 | 0.00 | 15.71 |
| 2013 | 72.96 | 10.28 | 16.88 | 16.53 | 10.55 | 16.37 | 16.21 | 19.28 | 0.00 | 15.90 |
| 2014 | 73.97 | 10.43 | 17.08 | 16.73 | 10.70 | 16.57 | 16.40 | 19.47 | 0.00 | 16.09 |
| 2015 | 75.00 | 10.58 | 17.28 | 16.92 | 10.85 | 16.76 | 16.60 | 19.67 | 0.00 | 16.29 |
| 2016 | 75.97 | 10.72 | 17.46 | 17.11 | 10.99 | 16.95 | 16.79 | 19.86 | 0.00 | 16.48 |
| 2017 | 76.96 | 10.87 | 17.65 | 17.29 | 11.14 | 17.14 | 16.98 | 20.05 | 0.00 | 16.67 |
| 2018 | 77.96 | 11.02 | 17.84 | 17.48 | 11.29 | 17.33 | 17.17 | 20.24 | 0.00 | 16.86 |
| 2019 | 78.97 | 11.17 | 18.04 | 17.68 | 11.44 | 17.53 | 17.36 | 20.43 | 0.00 | 17.06 |
| 2020 | 80.00 | 11.32 | 18.24 | 17.87 | 11.59 | 17.73 | 17.56 | 20.63 | 0.00 | 17.25 |
| 2021 | 81.91 | 11.60 | 18.60 | 18.23 | 11.87 | 18.09 | 17.92 | 21.00 | 0.00 | 17.62 |
| 2022 | 83.86 | 11.89 | 18.98 | 18.60 | 12.16 | 18.47 | 18.29 | 21.37 | 0.00 | 17.99 |
| 2023 | 85.86 | 12.18 | 19.36 | 18.98 | 12.45 | 18.85 | 18.67 | 21.76 | 0.00 | 18.38 |
| 2024 | 87.90 | 12.49 | 19.76 | 19.37 | 12.75 | 19.25 | 19.07 | 22.15 | 0.00 | 18.77 |
| 2025 | 90.00 | 12.80 | 20.16 | 19.77 | 13.06 | 19.65 | 19.47 | 22.55 | 0.00 | 19.18 |
| 2026 | 90.98 | 12.94 | 20.35 | 19.95 | 13.21 | 19.84 | 19.65 | 22.74 | 0.00 | 19.36 |
| 2027 | 91.97 | 13.09 | 20.54 | 20.14 | 13.35 | 20.03 | 19.84 | 22.93 | 0.00 | 19.55 |
| 2028 | 92.97 | 13.23 | 20.73 | 20.33 | 13.50 | 20.22 | 20.03 | 23.12 | 0.00 | 19.75 |
| 2029 | 93.98 | 13.38 | 20.92 | 20.52 | 13.65 | 20.41 | 20.23 | 23.32 | 0.00 | 19.94 |
| 2030 | 95.00 | 13.53 | 21.12 | 20.72 | 13.80 | 20.61 | 20.42 | 23.52 | 0.00 | 20.14 |

**Table A4-4: Coal Price Forecasts**
**2006$/MMBtu**
**Medhi Case**

| | | | Selected Regional Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | West WA/OR | East WA/OR | Idaho | Montana | Utah | Wyoming |
| 2005 | 0.48 | 2.11 | 1.40 | 1.22 | 0.82 | 0.78 | 0.67 | 0.58 |
| 2006 | 0.54 | 2.08 | 1.43 | 1.25 | 0.87 | 0.83 | 0.72 | 0.64 |
| 2007 | 0.56 | 2.09 | 1.45 | 1.27 | 0.89 | 0.85 | 0.75 | 0.66 |
| 2008 | 0.82 | 1.92 | 1.54 | 1.39 | 1.08 | 1.05 | 0.96 | 0.89 |
| 2009 | 0.70 | 3.12 | 1.93 | 1.68 | 1.15 | 1.10 | 0.95 | 0.83 |
| 2010 | 0.70 | 2.28 | 1.61 | 1.42 | 1.04 | 1.00 | 0.89 | 0.80 |
| 2011 | 0.71 | 2.21 | 1.58 | 1.40 | 1.03 | 0.99 | 0.89 | 0.81 |
| 2012 | 0.72 | 2.21 | 1.58 | 1.41 | 1.04 | 1.00 | 0.89 | 0.81 |
| 2013 | 0.72 | 2.22 | 1.59 | 1.42 | 1.04 | 1.00 | 0.90 | 0.82 |
| 2014 | 0.73 | 2.23 | 1.60 | 1.42 | 1.05 | 1.01 | 0.91 | 0.82 |
| 2015 | 0.73 | 2.23 | 1.60 | 1.43 | 1.05 | 1.02 | 0.91 | 0.83 |
| 2016 | 0.74 | 2.24 | 1.61 | 1.43 | 1.06 | 1.02 | 0.92 | 0.83 |
| 2017 | 0.75 | 2.24 | 1.61 | 1.44 | 1.07 | 1.03 | 0.92 | 0.84 |
| 2018 | 0.75 | 2.25 | 1.62 | 1.44 | 1.07 | 1.03 | 0.93 | 0.85 |
| 2019 | 0.76 | 2.25 | 1.63 | 1.45 | 1.08 | 1.04 | 0.94 | 0.85 |
| 2020 | 0.76 | 2.26 | 1.63 | 1.46 | 1.08 | 1.05 | 0.94 | 0.86 |
| 2021 | 0.77 | 2.27 | 1.64 | 1.46 | 1.09 | 1.05 | 0.95 | 0.86 |
| 2022 | 0.78 | 2.28 | 1.65 | 1.47 | 1.10 | 1.06 | 0.95 | 0.87 |
| 2023 | 0.78 | 2.28 | 1.65 | 1.48 | 1.10 | 1.06 | 0.96 | 0.88 |
| 2024 | 0.79 | 2.29 | 1.66 | 1.48 | 1.11 | 1.07 | 0.97 | 0.88 |
| 2025 | 0.79 | 2.30 | 1.66 | 1.49 | 1.11 | 1.08 | 0.97 | 0.89 |
| 2026 | 0.80 | 2.30 | 1.67 | 1.49 | 1.12 | 1.08 | 0.98 | 0.90 |
| 2027 | 0.81 | 2.30 | 1.68 | 1.50 | 1.13 | 1.09 | 0.99 | 0.90 |
| 2028 | 0.81 | 2.31 | 1.68 | 1.51 | 1.13 | 1.10 | 0.99 | 0.91 |
| 2029 | 0.82 | 2.32 | 1.69 | 1.51 | 1.14 | 1.10 | 1.00 | 0.92 |
| 2030 | 0.83 | 2.32 | 1.69 | 1.52 | 1.15 | 1.11 | 1.00 | 0.92 |

# Appendix A5: High Case Fuel Price Forecast Tables

**Table A5-1: Natural Gas Prices at Key Hubs and Northwest Generators**
**2006$/MMBtu**
**High Case**

| Year | Henry Hub Natural Gas Price | AECO Price | Sumas Price | West-Side Delivered | East-Side Delivered |
|---|---|---|---|---|---|
| 2005 | 7.95 | 6.98 | 7.08 | 7.70 | 7.58 |
| 2006 | 6.72 | 5.84 | 5.95 | 6.56 | 6.42 |
| 2007 | 6.53 | 5.67 | 5.78 | 6.38 | 6.24 |
| 2008 | 8.12 | 7.08 | 7.72 | 8.41 | 7.68 |
| 2009 | 4.29 | 3.65 | 4.24 | 4.90 | 4.21 |
| 2010 | 5.39 | 4.64 | 5.24 | 6.00 | 5.26 |
| 2011 | 5.93 | 5.13 | 5.74 | 6.57 | 5.80 |
| 2012 | 6.53 | 5.66 | 6.28 | 7.14 | 6.40 |
| 2013 | 7.19 | 6.25 | 6.88 | 7.75 | 7.00 |
| 2014 | 7.91 | 6.89 | 7.53 | 8.43 | 7.66 |
| 2015 | 8.70 | 7.60 | 8.26 | 9.17 | 8.38 |
| 2016 | 8.81 | 7.70 | 8.35 | 9.27 | 8.49 |
| 2017 | 8.92 | 7.80 | 8.45 | 9.38 | 8.59 |
| 2018 | 9.03 | 7.90 | 8.55 | 9.49 | 8.71 |
| 2019 | 9.14 | 8.00 | 8.66 | 9.60 | 8.81 |
| 2020 | 9.25 | 8.10 | 8.76 | 9.71 | 8.91 |
| 2021 | 9.36 | 8.20 | 8.86 | 9.81 | 9.01 |
| 2022 | 9.47 | 8.29 | 8.96 | 9.92 | 9.12 |
| 2023 | 9.58 | 8.39 | 9.06 | 10.03 | 9.22 |
| 2024 | 9.69 | 8.49 | 9.16 | 10.14 | 9.33 |
| 2025 | 9.80 | 8.59 | 9.26 | 10.25 | 9.44 |
| 2026 | 10.02 | 8.78 | 9.45 | 10.45 | 9.64 |
| 2027 | 10.23 | 8.98 | 9.65 | 10.65 | 9.84 |
| 2028 | 10.45 | 9.17 | 9.85 | 10.86 | 10.04 |
| 2029 | 10.68 | 9.38 | 10.06 | 11.08 | 10.25 |
| 2030 | 10.91 | 9.58 | 10.27 | 11.30 | 10.47 |

**Table A5-2: Wellhead and Retail Natural Gas Prices**
**2006$/MMBtu**
**High Case**

| Year | U.S. Wellhead Prices | Regional Retail Natural Gas Prices | | | |
|---|---|---|---|---|---|
| | | Residential | Commercial | Industrial | Utility Average |
| 2005 | 7.36 | 12.66 | 11.16 | 8.26 | 7.64 |
| 2006 | 6.23 | 11.53 | 10.03 | 7.12 | 6.49 |
| 2007 | 6.06 | 11.36 | 9.86 | 6.95 | 6.31 |
| 2008 | 7.47 | 12.77 | 11.27 | 8.76 | 8.03 |
| 2009 | 4.00 | 9.30 | 7.80 | 5.23 | 4.53 |
| 2010 | 5.00 | 10.30 | 8.80 | 6.24 | 5.57 |
| 2011 | 5.49 | 10.80 | 9.29 | 6.74 | 6.10 |
| 2012 | 6.03 | 11.34 | 9.83 | 7.30 | 6.67 |
| 2013 | 6.63 | 11.93 | 10.43 | 7.90 | 7.27 |
| 2014 | 7.28 | 12.59 | 11.08 | 8.57 | 7.94 |
| 2015 | 8.00 | 13.30 | 11.80 | 9.30 | 8.67 |
| 2016 | 8.10 | 13.40 | 11.90 | 9.40 | 8.77 |
| 2017 | 8.20 | 13.50 | 12.00 | 9.50 | 8.87 |
| 2018 | 8.30 | 13.60 | 12.10 | 9.60 | 8.98 |
| 2019 | 8.40 | 13.70 | 12.20 | 9.70 | 9.08 |
| 2020 | 8.50 | 13.80 | 12.30 | 9.81 | 9.19 |
| 2021 | 8.60 | 13.90 | 12.40 | 9.90 | 9.29 |
| 2022 | 8.70 | 14.00 | 12.50 | 10.01 | 9.39 |
| 2023 | 8.80 | 14.10 | 12.60 | 10.11 | 9.50 |
| 2024 | 8.90 | 14.20 | 12.70 | 10.21 | 9.60 |
| 2025 | 9.00 | 14.30 | 12.80 | 10.31 | 9.71 |
| 2026 | 9.19 | 14.50 | 12.99 | 10.51 | 9.91 |
| 2027 | 9.39 | 14.69 | 13.19 | 10.71 | 10.11 |
| 2028 | 9.59 | 14.89 | 13.39 | 10.91 | 10.31 |
| 2029 | 9.79 | 15.10 | 13.59 | 11.12 | 10.52 |
| 2030 | 10.00 | 15.30 | 13.80 | 11.33 | 10.74 |

**Table A5-3: World Oil Prices and Retail Oil Product Prices**
**2006$/MMBtu**
**High Case**

| Year | World Oil Prices | Industrial Residual Oil Price | Industrial | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 50.40 | 6.95 | 12.55 | 12.25 | 7.22 | 12.04 | 11.90 | 14.94 | 0.00 | 11.56 |
| 2006 | 59.02 | 8.22 | 14.20 | 13.89 | 8.49 | 13.69 | 13.55 | 16.60 | 0.00 | 13.22 |
| 2007 | 65.29 | 9.15 | 15.41 | 15.08 | 9.41 | 14.90 | 14.74 | 17.80 | 0.00 | 14.42 |
| 2008 | 0.00 | -0.50 | 2.85 | 2.68 | -0.23 | 2.34 | 2.27 | 5.25 | 0.00 | 1.87 |
| 2009 | 60.00 | 8.37 | 14.39 | 14.07 | 8.63 | 13.88 | 13.73 | 16.79 | 0.00 | 13.41 |
| 2010 | 75.00 | 10.58 | 17.28 | 16.92 | 10.85 | 16.76 | 16.60 | 19.67 | 0.00 | 16.29 |
| 2011 | 76.90 | 10.86 | 17.64 | 17.28 | 11.13 | 17.13 | 16.96 | 20.04 | 0.00 | 16.66 |
| 2012 | 78.85 | 11.15 | 18.02 | 17.65 | 11.42 | 17.51 | 17.34 | 20.41 | 0.00 | 17.03 |
| 2013 | 80.85 | 11.44 | 18.40 | 18.03 | 11.71 | 17.89 | 17.72 | 20.79 | 0.00 | 17.42 |
| 2014 | 82.90 | 11.75 | 18.79 | 18.42 | 12.02 | 18.28 | 18.11 | 21.19 | 0.00 | 17.81 |
| 2015 | 85.00 | 12.06 | 19.20 | 18.82 | 12.33 | 18.69 | 18.51 | 21.59 | 0.00 | 18.21 |
| 2016 | 86.36 | 12.26 | 19.46 | 19.08 | 12.53 | 18.95 | 18.77 | 21.85 | 0.00 | 18.47 |
| 2017 | 87.73 | 12.46 | 19.72 | 19.34 | 12.73 | 19.21 | 19.03 | 22.12 | 0.00 | 18.74 |
| 2018 | 89.13 | 12.67 | 19.99 | 19.60 | 12.94 | 19.48 | 19.30 | 22.39 | 0.00 | 19.01 |
| 2019 | 90.56 | 12.88 | 20.27 | 19.87 | 13.15 | 19.76 | 19.57 | 22.66 | 0.00 | 19.28 |
| 2020 | 92.00 | 13.09 | 20.54 | 20.15 | 13.36 | 20.03 | 19.85 | 22.94 | 0.00 | 19.56 |
| 2021 | 95.35 | 13.59 | 21.19 | 20.78 | 13.85 | 20.68 | 20.49 | 23.58 | 0.00 | 20.20 |
| 2022 | 98.82 | 14.10 | 21.85 | 21.44 | 14.37 | 21.34 | 21.15 | 24.25 | 0.00 | 20.87 |
| 2023 | 102.41 | 14.63 | 22.55 | 22.13 | 14.90 | 22.04 | 21.84 | 24.94 | 0.00 | 21.56 |
| 2024 | 106.14 | 15.18 | 23.26 | 22.83 | 15.45 | 22.75 | 22.55 | 25.66 | 0.00 | 22.28 |
| 2025 | 110.00 | 15.75 | 24.00 | 23.57 | 16.02 | 23.49 | 23.29 | 26.40 | 0.00 | 23.02 |
| 2026 | 111.93 | 16.03 | 24.38 | 23.93 | 16.30 | 23.87 | 23.66 | 26.77 | 0.00 | 23.39 |
| 2027 | 113.90 | 16.32 | 24.75 | 24.31 | 16.59 | 24.24 | 24.03 | 27.15 | 0.00 | 23.77 |
| 2028 | 115.90 | 16.62 | 25.14 | 24.69 | 16.89 | 24.63 | 24.41 | 27.53 | 0.00 | 24.15 |
| 2029 | 117.93 | 16.92 | 25.53 | 25.07 | 17.19 | 25.02 | 24.80 | 27.92 | 0.00 | 24.55 |
| 2030 | 120.00 | 17.23 | 25.93 | 25.47 | 17.49 | 25.42 | 25.20 | 28.32 | 0.00 | 24.94 |

**Table A5-4: Coal Price Forecasts**
**2006$/MMBtu**
**High Case**

| | | | Selected Regional Electricity Generation Coal Prices | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Western Minemouth Price | Regional Industrial Price | West WA/OR | East WA/OR | Idaho | Montana | Utah | Wyoming |
| 2005 | 0.48 | 2.11 | 1.40 | 1.22 | 0.82 | 0.78 | 0.67 | 0.58 |
| 2006 | 0.54 | 2.08 | 1.43 | 1.25 | 0.87 | 0.83 | 0.72 | 0.64 |
| 2007 | 0.56 | 2.09 | 1.45 | 1.27 | 0.89 | 0.85 | 0.75 | 0.66 |
| 2008 | 0.82 | 1.92 | 1.54 | 1.39 | 1.08 | 1.05 | 0.96 | 0.89 |
| 2009 | 0.82 | 3.36 | 2.08 | 1.82 | 1.28 | 1.23 | 1.07 | 0.95 |
| 2010 | 0.83 | 2.41 | 1.73 | 1.55 | 1.16 | 1.12 | 1.01 | 0.92 |
| 2011 | 0.84 | 2.34 | 1.71 | 1.53 | 1.16 | 1.12 | 1.01 | 0.93 |
| 2012 | 0.85 | 2.35 | 1.72 | 1.54 | 1.17 | 1.13 | 1.02 | 0.94 |
| 2013 | 0.86 | 2.36 | 1.73 | 1.55 | 1.18 | 1.14 | 1.03 | 0.95 |
| 2014 | 0.87 | 2.37 | 1.74 | 1.56 | 1.19 | 1.15 | 1.04 | 0.96 |
| 2015 | 0.88 | 2.38 | 1.75 | 1.57 | 1.20 | 1.16 | 1.05 | 0.97 |
| 2016 | 0.89 | 2.39 | 1.76 | 1.58 | 1.21 | 1.17 | 1.07 | 0.98 |
| 2017 | 0.90 | 2.40 | 1.77 | 1.59 | 1.22 | 1.18 | 1.08 | 0.99 |
| 2018 | 0.91 | 2.41 | 1.78 | 1.60 | 1.23 | 1.19 | 1.09 | 1.00 |
| 2019 | 0.92 | 2.42 | 1.79 | 1.61 | 1.24 | 1.20 | 1.10 | 1.01 |
| 2020 | 0.93 | 2.43 | 1.80 | 1.62 | 1.25 | 1.21 | 1.11 | 1.03 |
| 2021 | 0.94 | 2.45 | 1.81 | 1.64 | 1.26 | 1.23 | 1.12 | 1.04 |
| 2022 | 0.95 | 2.46 | 1.82 | 1.65 | 1.27 | 1.24 | 1.13 | 1.05 |
| 2023 | 0.96 | 2.47 | 1.84 | 1.66 | 1.29 | 1.25 | 1.14 | 1.06 |
| 2024 | 0.98 | 2.48 | 1.85 | 1.67 | 1.30 | 1.26 | 1.15 | 1.07 |
| 2025 | 0.99 | 2.50 | 1.86 | 1.68 | 1.31 | 1.27 | 1.17 | 1.08 |
| 2026 | 1.00 | 2.50 | 1.87 | 1.69 | 1.32 | 1.28 | 1.18 | 1.09 |
| 2027 | 1.01 | 2.51 | 1.88 | 1.71 | 1.33 | 1.29 | 1.19 | 1.11 |
| 2028 | 1.02 | 2.52 | 1.89 | 1.72 | 1.34 | 1.31 | 1.20 | 1.12 |
| 2029 | 1.04 | 2.54 | 1.90 | 1.73 | 1.36 | 1.32 | 1.21 | 1.13 |
| 2030 | 1.05 | 2.55 | 1.92 | 1.74 | 1.37 | 1.33 | 1.23 | 1.14 |

# Appendix A6: Fuel Price Forecasting Model

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Commodity Prices .... 40
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## INTRODUCTION

This paper describes the fuel price forecasting model that is used for the Council's Sixth Power Plan. The model consists of several worksheets linked together in an EXCEL "workbook". The Excel model used for the final forecast is in Q:\TM\FUEL\MODF\FUELMOD7(2) Rev 092309.xls.

The model includes forecasts of natural gas, oil, and coal prices. These prices are forecast for fuel commodity prices, wholesale, and retail level prices. Retail fuel prices for various demand sectors are derived from forecasts of basic energy commodity prices; that is, the average wellhead price of natural gas, the world price of oil, and Powder River Basin (PRB) minemouth coal prices. These energy commodity prices are forecast by several organizations that specialize in energy market forecasting. Thus basic energy commodity price trends can be based on 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 derived from the basic energy commodity prices. The approach for doing this varies by type of fuel and region. Where possible these additional costs, or markups, are based on historical relationships among energy costs to various geographic areas and economic sectors.

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 for electricity generation and receives less attention. Coal plays little role in determining electricity demand, but is an important fuel for electricity generation. It is treated briefly in the model using assumed annual growth rates of minemouth prices in the PRB, which is the primary source of coal for the region. The delivered price of coal to various locations is estimated based on distance and an estimated cost per ton-mile for unit coal trains escalated for changes in the cost of diesel fuel.

These Commodity price forecasts are developed in a separate workbook called "Fuel Price FC Dev For Final 6thPlan 092309.xls" and then copied into the fuel price model. WOPFC, NGFC, and COALFC are tabs in the FUELMOD7(2) Rev 092309.xls Excel Workbook where forecasts of world oil prices, natural gas wellhead prices, and PRB coal prices, respectively, are entered.

Historical regional retail price data for each fuel are kept on separate Excel files called OIL.XLS, GAS.XLS, and COAL.XLS. 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. State level prices are weighted by consumption levels to estimate regional prices. The spreadsheets convert the prices to constant or real dollars.

In FUELMOD7(2) Rev 092309.xls, the tab labeled "Deflation" contains implicit deflators for U.S. Gross Domestic Product (GDP). In cell D5, the user can specify what year constant dollars the forecasts will be expressed in. Labels for columns throughout the model are created here and used for reference in other tabs.

MAIN is the tab in FUELMOD7(2) Rev 092309.xls where a model forecast is set up. The scenario (L, ML, M, MH, or H) is selected from a drop down menu in cell B2. The forecast for the chosen scenario is selected by the model from the WOPFC, NGFC, and COALFC tabs. Commodity prices feed into the further tabs that develop regional wholesale and retail fuel prices. Main also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices: a burner-tip cost comparison. Other parameters and scenario varying assumptions also appear in this tab. The varying scenario parameters and their cell locations are as follows:

| | |
|---|---|
| Scenario Name | B2 |
| Wellhead Natural Gas Price | B9:B59 |
| World Oil Price | C9:C59 |
| Real Growth Rate of Incremental Pipeline Costs | H68:L68 |
| Firm Natural Gas Supply Share | H70:L70 |

The separate tabs in FUELMOD7(2) Rev 092309.xls are described in the Appendix, which is a printout of the first tab ("DOC") in the model. The model structure is described in more detail below for each fuel type.

## *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.

There are twelve separate worksheets for natural gas price model. These worksheets are described in the "DOC" tab of FUELMOD7(2) Rev 092309.xls, which is reproduced as Attachment A6-1 to this documentation.

## Commodity Prices

The forecasts start from forecasts of average annual lower-48 wellhead natural gas prices. Annual wellhead prices are converted to monthly wellhead prices using an econometric relationship that estimates systematic monthly patterns in prices. Monthly wellhead prices are converted to Henry Hub spot prices using another econometric relationship. Basis differentials from the Henry Hub prices to various pricing hubs in the West are then estimated based on Henry Hub prices. The pricing hubs included in the model are AECO-NIT in Alberta, Sumas at the B.C. and Washington border, U.S. Rocky Mountains, Permian, and San Juan.

The commodity price equations were re-estimated by Chris Collier in the summer of 2008.[5] The original equations were estimated for the Fifth Power Plan by Terry Morlan.[6] The latter included equations for prices to electricity generators discussed in the next section.

Seasonal variations were captured in the hub price equations by including Fourier series in some of the equations. The Fourier series equations that were used in the regressions are:

S1 =SIN((2*3.14159*1 *Month)/12)
S2= SIN((2*3.14159*2 *Month)/12)
C1= COS((2*3.14159*1 *Month)/12)
C2= COS((2*3.14159*2 *Month)/12)

Where Month = what number of month in the year is it. Example: January =1, February= 2,..., Dec.=12

### *Annual Wellhead to Monthly Wellhead*

The first step in the forecasting process was to find a relationship between annual wellhead prices and monthly wellhead prices that would provide the ability to forecast monthly wellhead price. The U.S. Energy Information Administration (EIA) provides wellhead data (both monthly and annually) since 1973, but when determining relationships only data starting from January 1989 was used. In January 1989, deregulation of the natural gas market occurred which allowed prices to more accurately reflect natural gas market forces. When running a regression in order to determine the relationship between the annual and monthly prices the Fourier series played an important role. Table A6-1 shows the estimated equation and fit statistics.

The estimated relationship is used to determine monthly wellhead prices is:

Wellhead Monthly= -.00497+ 1.000651 * Annual Wellhead + C1 * 0.201547+ C2 * 0.131491

Where: Wellhead Monthly = The monthly wellhead price of natural gas
Annual Wellhead = The annual wellhead price of natural gas
C1 = A fourier series with highest value in winter
C2 = A fourier series with low values in shoulder months

[5] Chris Collier. "Natural Gas Forecast". August 2008.
[6] "Developing Basis Relationships Among Western Natural Gas Pricing Points". Northwest Power and Conservation Council. 2004.

This equation results in a better estimation of monthly wellhead prices, given a forecast of annual wellhead prices. There were no dummy variables included in this regression because the annual wellhead prices is an average of the twelve months in the year therefore, any one time events are already picked up.

**Table A6-1: Monthly Wellhead Price as a Function of Annual Wellhead Price**

| *Regression Statistics* | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.954957 | | | | | |
| **R Square** | 0.911943 | | | | | |
| **Adjusted R Square** | 0.910763 | | | | | |
| **Standard Error** | 0.58542 | | | | | |
| **Observations** | 228 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | |
| **Regression** | 3 | 795.0336287 | 265.0112 | 773.2671 | 7.4532E-118 | |
| **Residual** | 224 | 76.76843926 | 0.342716 | | | |
| **Total** | 227 | 871.802068 | | | | |
| | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
| **Intercept** | -0.00497 | 0.07830 | -0.0635 | 95% | -0.159262805 | 0.149319 |
| **Annual Wellhead** | 1.000651 | 0.02086 | 47.96393 | 0% | 0.959538585 | 1.041763 |
| **C1(Fourier Series)** | 0.201547 | 0.05483 | 3.675874 | 0% | 0.093498869 | 0.309594 |
| **C2(Fourier Series)** | 0.131491 | 0.05483 | 2.398173 | 2% | 0.023443069 | 0.239539 |

### *Monthly Wellhead to Monthly Henry Hub Spot Price*

Unlike the majority of natural gas hubs in the United States, Henry Hub is traded on the New York Mercantile Exchange (NYMEX) and is the most important natural gas trading hub in the United States. Data for Henry Hub spot prices is very accessible and Henry Hub prices factor into regional natural gas prices because Henry Hub is the main hub in the United States. That being, it was imperative that to find a close relationship between monthly wellhead prices and monthly Henry Hub spot prices.

When attempting to find a relationship between Monthly Wellhead Prices and Monthly Henry Hub Spot Prices, two dummy variables were used. The first dummy variable is a replication of the dummy variable used to adjust for outlier months. The second dummy variable used in order to adjust for the prices increases caused by Hurricanes Katrina and Rita in 2005.

The estimated relationship is:

HH= .1237 + 1.1029 * Wellhead monthly + 1.3809 * D1 + 1.5201 * D2

Where: HH = the Henry Hub Spot Price

D1 = Dummy Variable for Outlier Months: Outlier Months are: 1,2,3 1996; 11,12, 2000; 1, 2001; 2, 3, 2003

D2= Dummy Variable for Extreme Weather Katrina: Katrina months are: 8,9,10,11,12, 2005

Table A6-2 shows regression results. The value of the R-squared indicates that the equation is able to explain 97 percent of the month to month variation of the Henry Hub prices about their mean.

**Table A6-2: Henry Hub Spot Price as a Function of Wellhead Price**

| *Regression Statistics* | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.98644074 | | | | | |
| **R Square** | 0.97306534 | | | | | |
| **Adjusted R Square** | 0.97270461 | | | | | |
| **Standard Error** | 0.3892528 | | | | | |
| **Observations** | 228 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | |
| **Regression** | 3 | 1226.145 | 408.7152 | 2697.474 | 1.85E-175 | |
| **Residual** | 224 | 33.93997 | 0.151518 | | | |
| **Total** | 227 | 1260.085 | | | | |
| | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
| **Intercept** | -0.12372615 | 0.053171 | -2.32695 | 2% | -0.228505 | -0.018946975 |
| **Wellhead Monthly** | 1.10296041 | 0.015038 | 73.34706 | 0% | 1.0733272 | 1.132593579 |
| **D1(Outliers)** | 1.38094005 | 0.141527 | 9.757431 | 0% | 1.1020454 | 1.659834715 |
| **D2 (Katrina)** | 1.52019919 | 0.18272 | 8.319845 | 0% | 1.1601298 | 1.880268532 |

### *AECO*

The AECO- NIT trading hub is located in southeast Alberta, Canada and is the primary trading hub for natural gas produced in the Western Canada Sedimentary Basin (WCSB). Prices at the AECO trading hub tend to be lower than natural gas prices at Henry Hub because the WSCB has been a growing supply area with limited pipeline capacity to export natural gas. AECO plays an important roll in northwest natural gas prices because a large portion of the region's natural gas supply comes from the WCSB.

AECO price data was not available before January of 1995. Since that time AECO prices averaged $.86 less than Henry Hub Prices. The relationship between AECO and Henry Hub prices are estimated from January 1995 to December 2007. The equation is:

AECO = -0.5305+ 0.89564 * Henry Hub -1.44438 * D1 - 0.79599 * D2+ 0.3425 * D3

Where: AECO = natural gas price at the AECO-NIT hub;
Henry Hub = Henry Hub natural gas price;
D1= Dummy Variable due to harsh winter months (Months are 1,2,3, 12, 1996);
D2= Dummy Variable for Hurricane Katrina (Months are 8,9,10,11,12, 2005; 1, 2006);

D3 = Dummy for the opening of the Alliance pipeline in December 2000 (All months after December 2000).

The addition of the Alliance Pipeline capacity is estimated to have raised AECO prices an average of $.34. This is assumed to affect future prices therefore; D3 is carried over into the forecasting period. Table A6-3 shows the detailed estimation results.

**Table A6-3: AECO Prices as a function of Henry Hub Prices**

| *Regression Statistics* | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.984038 | | | | | |
| **R Square** | 0.968331 | | | | | |
| **Adjusted R Square** | 0.967492 | | | | | |
| **Standard Error** | 0.411699 | | | | | |
| **Observations** | 156 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | |
| **Regression** | 4 | 782.5753 | 195.6438 | 1154.269 | 4.653E-112 | |
| **Residual** | 151 | 25.59389 | 0.169496 | | | |
| **Total** | 155 | 808.1692 | | | | |
| | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
| **Intercept** | -0.5305 | 0.07774 | -6.82408 | 0% | -0.684101754 | -0.3769 |
| **Henry Hub** | 0.89564 | 0.024143 | 37.09798 | 0% | 0.847939198 | 0.943341 |
| **D1(Winter)** | -1.44438 | 0.244074 | -5.9178 | 0% | -1.926623922 | -0.96214 |
| **D2(Hurricane)** | -0.79599 | 0.219869 | -3.62029 | 0% | -1.230403991 | -0.36157 |
| **D3 Pipeline** | 0.342524 | 0.100763 | 3.399292 | 0% | 0.143436072 | 0.541613 |

### *Rockies*

The U.S. Rocky Mountain area is another major source of natural gas supplies to the Pacific Northwest. The natural gas hub used in this analysis is named Opal. It is the main hub located in the Rocky Mountain area and supplies natural gas to the east and the west. The Rockies are a rapidly growing supply area and many new pipeline proposals, if implemented, will greatly affect natural gas prices. Since the deregulation of the natural gas market in 1989, Rockies prices averaged $.80 less than Henry Hub prices. Recently, new pipeline proposals have been announced in an attempt to move growing Rocky Mountain natural gas supplies out of that region.

When estimating the relationship between Rockies and Henry Hub prices the same dummy variables as used in the earlier fuel price forecasting model were included, but an additional dummy variable incorporated to adjusted for the depressed Rockies prices that occurred during 2007 due to pipeline capacity constraints. The pipeline capacity constraint created an excess supply of natural gas causing a disconnect between the two hubs and significantly depressing Rockies prices because of excess supply. Also, in this relationship the Fourier series picked up consistent monthly patterns that were significant.

The estimated equation relating Rockies natural gas prices to Henry Hub prices is as follows:

Rockies = -0.0603 + 0.829485 * Henry Hub + .1279 * S1+ .0981 * C1 - 1.7675 * D1 + .2176 * D2 - 1.01625 * D3 - 2.2327 * D4

Where: Rockies = The Rocky Mountain natural gas price at Opal;
Henry Hub= Henry Hub natural gas price;
S1 = Fourier series (see page 3);
C1 = Fourier series (see page 3);
D1 = Dummy for months 1, 2, 3 1996;
D2 = Dummy for months in 1998 through 2001;
D3 = Dummy for depressed Rockies prices in 2002-03;
D4 = Dummy for depressed Rockies prices in 2007 for pipeline constraints (Months: 3, 4, 5, 6, 7, 8, 9, 10, 11, 2007).

Table A6-4 shows the detailed estimation results. The Rockies are important to monitor because prices will vary with the growth in supply relative to additions to the pipeline capacity to move natural gas out of the region.

**Table A6-4: Rockies as a Function of Henry Hub Prices**

| *Regression Statistics* | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.978661 | | | | | |
| **R Square** | 0.957777 | | | | | |
| **Adjusted R Square** | 0.956433 | | | | | |
| **Standard Error** | 0.400115 | | | | | |
| **Observations** | 228 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | |
| **Regression** | 7 | 798.9267 | 114.1324 | 712.917 | 2.3E-147 | |
| **Residual** | 220 | 35.22026 | 0.160092 | | | |
| **Total** | 227 | 834.147 | | | | |
| | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
| **Intercept** | -0.06029 | 0.051794 | -1.16398 | 25% | -0.16236 | 0.041789 |
| **Henry Hub** | 0.829485 | 0.011997 | 69.13946 | 0% | 0.80584 | 0.853129 |
| **S1** | 0.127993 | 0.037871 | 3.379753 | 0% | 0.053358 | 0.202629 |
| **C1** | 0.098133 | 0.038034 | 2.58014 | 1% | 0.023175 | 0.17309 |
| **D1(1996)** | -1.7675 | 0.235826 | -7.49495 | 0% | -2.23227 | -1.30273 |
| **D2(98-01)** | 0.217687 | 0.066249 | 3.28587 | 0% | 0.087122 | 0.348251 |
| **D3(2002-03)** | -1.01625 | 0.109772 | -9.25786 | 0% | -1.23259 | -0.79991 |
| **D4(2007)** | -2.23276 | 0.144406 | -15.4617 | 0% | -2.51736 | -1.94817 |

### *San Juan*

The San Juan market area is focused on Colorado and New Mexico. The San Juan prices tend to be similar to Rockies prices in relation to Henry Hub prices. However, the San Juan prices were not affected in 2007 by pipeline capacity constraints which caused the depression of the Rockies prices. When determining the relationship between San Juan prices and Henry Hub prices the same dummy variables were used in the earlier fuel price forecasting model.

The estimated equation for the San Juan natural gas price as a function of the Henry Hub price is shown below. The detailed estimation statistics are shown in Table A6-5.

San Juan = 0.1701+ 0.8243 * HH - 1.9103 * D1 + 0.5721 * D2 - 0.40914 * Drockies + 0.0747 * S2 + 0.0786 * C1

Where: San Juan = the San Juan price for natural gas
HH = the Henry Hub prices for natural gas
D1 = when Henry Hub prices were abnormally high
D2 = a dummy adjusting for the energy crisis (DRockies is a dummy adjusting for pipeline capacity constraint during 2002 and early 2003)

**Table A6-5: San Juan Price as a Function of Henry Hub Prices**

| *Regression Statistics* | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.988726 | | | | | |
| **R Square** | 0.97758 | | | | | |
| **Adjusted R Square** | 0.976971 | | | | | |
| **Standard Error** | 0.30209 | | | | | |
| **Observations** | 228 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | *df* | *SS* | *MS* | *F* | *Significance F* | |
| **Regression** | 6 | 879.3847 | 146.5641 | 1606.039 | 3.3E-179 | |
| **Residual** | 221 | 20.16804 | 0.091258 | | | |
| **Total** | 227 | 899.5527 | | | | |
| | | | | | | |
| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
| **Intercept** | 0.170197 | 0.036777 | 4.627815 | 0% | 0.097718 | 0.242675 |
| **HH** | 0.82437 | 0.008732 | 94.4071 | 0% | 0.807162 | 0.841579 |
| **D1(1996)** | -1.91035 | 0.177006 | -10.7926 | 0% | -2.25919 | -1.56152 |
| **D2(2000-2001)** | 0.572165 | 0.181015 | 3.160868 | 0% | 0.215428 | 0.928902 |
| **Drockies** | -0.40914 | 0.076544 | -5.34521 | 0% | -0.55999 | -0.25829 |
| **S2** | 0.074781 | 0.028426 | 2.630784 | 1% | 0.018762 | 0.130801 |
| **C1** | 0.078688 | 0.02875 | 2.736927 | 1% | 0.022028 | 0.135348 |

In 2003 when the regressions for the fuel price forecasting model were run, San Juan prices averaged $.37 below Henry Hub prices. Since 2003, the difference between the two hubs has become larger. From 2003-2007, San Juan prices averaged $ 1.01 less than Henry Hub prices, but the gap between the two hubs has since retreated. Using the estimated equation from 2008-2030 San Juan prices averaged $.88 less than Henry Hub prices.

### *Permian*

The Permian basin pricing point is located in West Texas and supplies natural gas for Arizona and Southern California. Similar to San Juan hub prices, Permian basin prices averaged $ .20 less than Henry Hub prices during 1998-2003, but since 2003 Permian basin prices have averaged roughly $.75 less than Henry Hub spot prices. In this relationship, the same two dummy variables were used as in the earlier fuel price forecasting model but with the addition of a fourier series to capture regular cyclical patterns.

The estimated equation for the Permian Basis natural gas price as a function of the Henry Hub price is shown below. The detailed estimation statistics are shown in Table A6-6.

Permian = 0.1782 + 0.8552 * Henry Hub + 0.0601 * S2 + 0.5228 * D1 - 1.2478 * D2

Where: Permian = the Permian natural gas price
Henry Hub = the Henry Hub spot price
S2 = a Fourier series (see page 2)
D1 = a dummy variable for abnormal Henry Hub prices
D2 = a dummy variable for depressed Rockies prices due to the Kern River pipeline expansion

**Table A6-6: Permian Price as a function of Henry Hub Prices**

| Regression Statistics | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.994125 | | | | | |
| **R Square** | 0.988285 | | | | | |
| **Adjusted R Square** | 0.988074 | | | | | |
| **Standard Error** | 0.224765 | | | | | |
| **Observations** | 228 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | df | SS | MS | F | Significance F | |
| **Regression** | 4 | 950.3557 | 237.5889 | 4702.928 | 5.2E-214 | |
| **Residual** | 223 | 11.26582 | 0.050519 | | | |
| **Total** | 227 | 961.6215 | | | | |
| | | | | | | |
| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
| **Intercept** | 0.178285 | 0.027076 | 6.584636 | 0% | 0.124928 | 0.231643 |
| **Henry Hub** | 0.855245 | 0.006455 | 132.4937 | 0% | 0.842525 | 0.867966 |
| **S2** | 0.060191 | 0.021149 | 2.846038 | 0% | 0.018513 | 0.101869 |
| **D1 (1996)** | 0.522843 | 0.067973 | 7.691945 | 0% | 0.388892 | 0.656794 |
| **D2 (2003)** | -1.24789 | 0.131264 | -9.50667 | 0% | -1.50656 | -0.98921 |

During 2008-2030, the estimated equation forecasts Permian prices to be on average $ .64 below Henry Hub prices.

### *Sumas*

The estimated equation for the Sumas hub is different from the rest of the relationships that were found because Sumas prices are assumed to be related to prices at AECO and the Rockies. The Sumas natural gas hub is located in Sumas, Washington and has been an important factor in regional prices. It is the entry point for WCSB gas from British Columbia into Western Washington. Since Sumas is the entry point for WCSB gas, it is expected that Sumas prices will have a close relationship with AECO prices. Sumas hub prices will also be related to Rockies prices since the Williams pipeline connects Sumas and the Rockies region. The equation below was estimated on monthly data from January 1995 to December 2007 on a monthly basis, but some outlier observations in the data were left out. Due to depressed Rockies prices in 2007, a dummy variable was added to adjust for that one time event. Specifically, November 1996 through January 1997 and the same months in the 2000-2001 energy crisis were left out of the estimate.

The estimated equation for the Sumas hub natural gas price as a function of the Rockies and AECO prices is shown below. The detailed estimation statistics are shown in Table A6-7.

Sumas = 0.0140 + 0.1462 * Rockies + 0.8812 * AECO + 1.0570 * D1 +6.6626 * D3 + .7950 * D4

Where: Sumas = the Sumas natural gas price
Rockies = the Rockies natural gas price
AECO = the AECO natural gas prices
D1 = a dummy variable for the winter of 1996-97
D3 = a dummy for November and December 2000
D4 = a dummy for depressed Sumas prices since 2007

**Table A6-7: Sumas Price as a Function of AECO and Rockies Prices**

| Regression Statistics | | | | | | |
|---|---|---|---|---|---|---|
| **Multiple R** | 0.989085 | | | | | |
| **R Square** | 0.978289 | | | | | |
| **Adjusted R Square** | 0.977565 | | | | | |
| **Standard Error** | 0.38353 | | | | | |
| **Observations** | 156 | | | | | |
| | | | | | | |
| **ANOVA** | | | | | | |
| | df | SS | MS | F | Significance F | |
| **Regression** | 5 | 994.193758 | 198.8388 | 1351.77 | 8.7E-123 | |
| **Residual** | 150 | 22.06426511 | 0.147095 | | | |
| **Total** | 155 | 1016.258023 | | | | |
| | | | | | | |
| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
| **Intercept** | 0.014037 | 0.060378078 | 0.23249 | 0.816474 | -0.10526 | 0.133339 |
| **Rockies** | 0.146183 | 0.050933668 | 2.870066 | 0.004697 | 0.045543 | 0.246823 |
| **Aeco** | 0.881218 | 0.046601013 | 18.90985 | 1.52E-41 | 0.789139 | 0.973297 |
| **D1** | 1.056978 | 0.237214521 | 4.45579 | 1.63E-05 | 0.588265 | 1.525691 |
| **D3** | 6.662592 | 0.276408041 | 24.10419 | 1.88E-53 | 6.116436 | 7.208748 |
| **D4** | 0.794977 | 0.185935755 | 4.275546 | 3.38E-05 | 0.427585 | 1.162368 |

## Electric Generator Prices

The Aurora Model uses estimates of the price that will be paid by electric generators for natural gas. These prices are organized by supply areas that mostly coincide with states in the West. The exceptions are California and Nevada, which are divided into north and south, and the Pacific Northwest is divided into 4 areas that don’t coincide with state boundaries.

The data for natural gas prices to electric generators by state is from the Energy Information Administration. For several states in the West this data is thin and not representative of market price relationships. In these cases, equations that attempt to relate state electric generator natural gas prices to a nearby trading hub's prices fail. Reasonably good relationships were attained for Arizona, New Mexico, Colorado, and Nevada. Separate electric generator natural gas prices were available for northern and southern California from Natural Gas Week, and reasonable relationships were estimated for those. The estimated equation for Nevada is used for Southern Nevada, and Northern Nevada is estimated using a method described later in the Appendix.

The methods for the Pacific Northwest areas are discussed in a later section.

### *California South*

Southern California gets its natural gas supplies from the Permian area and, since 1992, from the Rockies. The opening of the Kern River Pipeline in 1992 brought Rockies natural gas to Southern California and changed the pricing. The equation below was estimated on data since April 1992 and excludes the period of the West Coast energy crisis in 2000-01 from the observations. Table A6-7 shows the detailed regression results.

CA_S = 0.328 + 0.782 * PERM + 0.203 * ROCK - 0.737 * D96SCA

Where: CA_S the Southern California natural gas price to utilities
D96SCA = dummy for the first half of 1996
PERM and ROCK = Permian and Rockies natural gas prices

**Table A6-7: Southern California Price as a Function of Permian and Rockies Prices**

| **Dependent Variable: CA_S** | | | | |
|---|---|---|---|---|
| **Method: Least Squares** | | | | |
| **Date: 04/15/04 Time: 13:23** | | | | |
| **Sample: 1992:04 2000:08 2001:08 2003:11** | | | | |
| **Included observations: 129** | | | | |
| **Variable** | Coefficient | Std. Error | t-Statistic | Prob. |
| **C** | 0.327675 | 0.058711 | 5.581203 | 0.0000 |
| **PERM** | 0.781839 | 0.043682 | 17.89829 | 0.0000 |
| **ROCK** | 0.203339 | 0.052878 | 3.845470 | 0.0002 |
| **D96SCA** | -0.736620 | 0.101784 | -7.237071 | 0.0000 |
| **R-squared** | 0.944423 | Mean dependent var | | 2.655116 |
| **Adjusted R-squared** | 0.943090 | S.D. dependent var | | 0.959815 |
| **S.E. of regression** | 0.228972 | Akaike info criterion | | -0.079915 |
| **Sum squared resid** | 6.553538 | Schwarz criterion | | 0.008762 |
| **Log likelihood** | 9.154506 | F-statistic | | 708.0507 |
| **Durbin-Watson stat** | 0.767842 | Prob(F-statistic) | | 0.000000 |

### *California North*

Northern California receives natural gas from the WCSB and from the Rockies. The following equation was estimated on data from January 1995 through November 2003. The period of the West Coast energy crisis was omitted from the observations. Figure A6-8 shows the detailed regression results.

CA_N = 0.436 + 0.581 * AECO + 0.463 * ROCK

Where: CA_N = the Northern California natural gas price
AECO and ROCK are as defined earlier

**Table A6-8: Northern California Price as a Function of AECO and Rockies Prices**

| **Dependent Variable: CA_N** | | | | |
|---|---|---|---|---|
| **Method: Least Squares** | | | | |
| **Date: 04/15/04 Time: 13:46** | | | | |
| **Sample: 1995:01 2000:10 2001:07 2003:11** | | | | |
| **Included observations: 99** | | | | |
| **Variable** | Coefficient | Std. Error | t-Statistic | Prob. |
| **C** | 0.435619 | 0.090815 | 4.796752 | 0.0000 |
| **AECO** | 0.581218 | 0.061551 | 9.442896 | 0.0000 |
| **ROCK** | 0.463417 | 0.076812 | 6.033145 | 0.0000 |
| **R-squared** | 0.906084 | Mean dependent var | | 2.665657 |
| **Adjusted R-squared** | 0.904128 | S.D. dependent var | | 1.148937 |
| **S.E. of regression** | 0.355748 | Akaike info criterion | | 0.800648 |
| **Sum squared resid** | 12.14947 | Schwarz criterion | | 0.879288 |
| **Log likelihood** | -36.63210 | F-statistic | | 463.0958 |
| **Durbin-Watson stat** | 0.687154 | Prob(F-statistic) | | 0.000000 |

### *Nevada*

Utility natural gas price data was only available for the entire state of Nevada, but the north would not be significantly influenced by Permian prices and the south not by AECO prices. Nevada is likely dominated by Southern Nevada (the Las Vegas area); and Southern Nevada is similar to Southern California. It can receive natural gas from the Permian basin or the Rockies. Northern Nevada is likely to be affected by AECO and Rockies, and AECO prices did show significance in the estimated equations for Nevada. The details of the equation below are contained in Table A6-9. The months from June 2001 through October 2002 were eliminated from the estimation. The equation is used for only Southern Nevada. Northern Nevada prices are estimated using the methods described in a later section.

NV = 0.798 + 0.468 * PERM + 0.370 * AECO - 0.869 * D96_97

Where: NV = utility natural gas prices in Nevada
AECO and PERM are as defined earlier
D96_97 = a dummy variable for November/December, 1996 and January, 1997

**Table A6-9: Nevada Price as a Function of Permian and Rockies Prices**

| | | | | |
|---|---|---|---|---|
| **Dependent Variable: NV** | | | | |
| **Method: Least Squares** | | | | |
| **Date: 04/21/04 Time: 16:10** | | | | |
| **Sample: 1995:01 2000:10** | | | | |
| **Included observations: 70** | | | | |
| **Variable** | Coefficient | Std. Error | t-Statistic | Prob. |
| **C** | 0.798370 | 0.086816 | 9.196139 | 0.0000 |
| **PERM** | 0.468088 | 0.068439 | 6.839446 | 0.0000 |
| **AECO** | 0.370051 | 0.065829 | 5.621396 | 0.0000 |
| **D96_97** | -0.869152 | 0.151518 | -5.736297 | 0.0000 |
| **R-squared** | 0.894748 | Mean dependent var | | 2.462147 |
| **Adjusted R-squared** | 0.889964 | S.D. dependent var | | 0.666755 |
| **S.E. of regression** | 0.221174 | Akaike info criterion | | -0.124293 |
| **Sum squared resid** | 3.228570 | Schwarz criterion | | 0.004192 |
| **Log likelihood** | 8.350259 | F-statistic | | 187.0230 |
| **Durbin-Watson stat** | 1.391586 | Prob(F-statistic) | | 0.000000 |

### *Arizona*

Arizona can access natural gas from the Permian and San Juan Basins via the El Paso and Transwestern pipelines. Arizona utility prices of natural gas are therefore based on the prices in these basins. The equation estimated is as follows:

AZ = 1.003 + 0.309 * PERM + 0.596 * SJ + 2.06 * D96_97

Where: AZ = the Arizona price of natural gas to electric utilities
PERM and SJ = Permian and San Juan prices
D96_97 = a dummy variable for Nov. and Dec. 1996 and Jan. 1997

The detailed estimation results are shown in Table A6-10

**Table A6-10: Arizona Price as a Function of Permian and San Juan Prices**

| | | | | |
|---|---|---|---|---|
| **Dependent Variable: AZ** | | | | |
| **Method: Least Squares** | | | | |
| **Date: 04/19/04 Time: 14:15** | | | | |
| **Sample: 1989:01 2003:08** | | | | |
| **Included observations: 176** | | | | |
| **Variable** | Coefficient | Std. Error | t-Statistic | Prob. |
| **C** | 1.002582 | 0.080535 | 12.44894 | 0.0000 |
| **PERM** | 0.308772 | 0.127064 | 2.430056 | 0.0161 |
| **SJ** | 0.596317 | 0.139524 | 4.273942 | 0.0000 |
| **D96_97** | 2.061088 | 0.262927 | 7.839012 | 0.0000 |
| **R-squared** | 0.853227 | Mean dependent var | | 3.195625 |
| **Adjusted R-squared** | 0.850667 | S.D. dependent var | | 1.157051 |
| **S.E. of regression** | 0.447126 | Akaike info criterion | | 1.250512 |
| **Sum squared resid** | 34.38652 | Schwarz criterion | | 1.322569 |
| **Log likelihood** | -106.0451 | F-statistic | | 333.2937 |
| **Durbin-Watson stat** | 1.224515 | Prob(F-statistic) | | 0.000000 |

### *New Mexico*

The situation in New Mexico is very similar to Arizona. The equation below determines New Mexico prices based on Permian and San Juan prices. Table A6-11 shows the detailed estimation results.

NM = 0.546 + 0.598 * PERM + 0.300 * SJ

Where NW = New Mexico natural gas prices and other variables are a defined earlier

**Table A6-11: New Mexico Price as a Function of Permian and San Juan Prices**

| **Dependent Variable: NM** | | | | |
|---|---|---|---|---|
| **Method: Least Squares** | | | | |
| **Date: 04/19/04 Time: 14:36** | | | | |
| **Sample: 1989:01 2003:08** | | | | |
| **Included observations: 176** | | | | |
| **Variable** | Coefficient | Std. Error | t-Statistic | Prob. |
| **C** | 0.546146 | 0.038924 | 14.03098 | 0.0000 |
| **PERM** | 0.597776 | 0.061494 | 9.720824 | 0.0000 |
| **SJ** | 0.299599 | 0.067418 | 4.443900 | 0.0000 |
| **R-squared** | 0.957544 | Mean dependent var | | 2.738460 |
| **Adjusted R-squared** | 0.957054 | S.D. dependent var | | 1.044997 |
| **S.E. of regression** | 0.216560 | Akaike info criterion | | -0.204998 |
| **Sum squared resid** | 8.113411 | Schwarz criterion | | -0.150955 |
| **Log likelihood** | 21.03979 | F-statistic | | 1950.921 |
| **Durbin-Watson stat** | 0.974070 | Prob(F-statistic) | | 0.000000 |

### *Colorado*

The equation for Colorado is as follows, with the detailed estimation results shown in Table A6-12.

CO = 1.163 + 0.730 * SJ - 0.899 * D_ROCKIES + 3.755 * D05_97

Where CO = the Colorado natural gas price to electric utilities
D05_97 = a dummy for May 1997
And other variables are as defined earlier

**Table A6-12: Coloado Price as a Function of San Juan Prices**

| Dependent Variable: CO | | | | |
|---|---|---|---|---|
| Method: Least Squares | | | | |
| Date: 04/15/04 Time: 11:08 | | | | |
| Sample: 1989:01 2003:08 | | | | |
| Included observations: 176 | | | | |
| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
| C | 1.162658 | 0.070299 | 16.53879 | 0.0000 |
| SJ | 0.730307 | 0.027868 | 26.20580 | 0.0000 |
| D_ROCKIES | -0.898657 | 0.135828 | -6.616119 | 0.0000 |
| D05_97 | 3.754979 | 0.391006 | 9.603368 | 0.0000 |
| R-squared | 0.817955 | Mean dependent var | | 2.834136 |
| Adjusted R-squared | 0.814779 | S.D. dependent var | | 0.905629 |
| S.E. of regression | 0.389758 | Akaike info criterion | | 0.975884 |
| Sum squared resid | 26.12874 | Schwarz criterion | | 1.047940 |
| Log likelihood | -81.87775 | F-statistic | | 257.6064 |
| Durbin-Watson stat | 1.492502 | Prob(F-statistic) | | 0.000000 |

## Other Areas

For some areas included in the Aurora model, it was not possible to estimate meaningful relationships between natural gas prices to utilities and trading hub prices. These areas included Utah, Wyoming, Northern Nevada, British Columbia, Alberta, and the Pacific Northwest areas. This is due to the nature of the utility gas price data, which is thin and displays little relationship to trading hub markets.

For these areas, the model uses estimated historical differentials or estimates of pipeline costs to estimate delivered costs to the demand areas. The methods for each area are described below.

### *Rocky Mountain States*

The current method for calculating utility natural gas prices in Utah, Wyoming, Northern Nevada, Alberta and British Columbia assumes a starting differential for each area from its most likely pricing hub (See Table A6-13). The pipeline reservation cost is assumed to be $.50 for existing customers. For new power plants these costs are assumed to be $.62 and escalate over time reflecting real pipeline capacity cost growth. This growth in incremental pipeline fixed costs amounts to a 32 percent increase over existing rolled-in cost by 2030. The rate of real growth in pipeline capacity costs after 2007 varies by forecast scenario (See Table A6-14).

**Table A6-13: Starting Pipeline Delivery Costs by State (2000$/MMBtu)**

| State | Hub |
|---|---|
| Utah | Rockies |
| Wyoming | Rockies |
| Northern Nevada | AECO |
| British Columbia | Sumas |
| Alberta | AECO |

**Table A6-14: Escalation of Incremental Pipeline Capacity Cost Post 2006 (%/Yr.)**

| Scenario | Escalation Rate |
|---|---|
| Low | - 0.1 % |
| Medium Low | 0.1 % |
| Medium | 0.3 % |
| Medium High | 0.5 % |
| High | 0.7 % |

### *Pacific Northwest Areas*

There are four separate areas modeled for the Pacific Northwest. These include Western Oregon and Washington, Eastern Oregon and Washington, Southern Idaho, and Western Montana. The delivery cost of natural gas to these areas is based on more detailed estimates of pipeline delivery costs from pricing hubs in the Northwest. The estimation of natural gas cost to the four PNW areas are based on the following relationships to market trading points. In the case of Western Oregon and Washington the related trading hub is assumed to be Sumas. In the case of Eastern Oregon and Washington (including Northern Idaho) and Western Montana it is assumed to be AECO. Southern Idaho is related to prices in the Rocky Mountains. The calculation takes the following general form.

Delivered Cost = Hub Price / (1 - in-kind fuel charge) + pipeline capacity reservation cost / plant capacity factor + pipeline commodity charge

Where: The in-kind fuel charge is a percent of the purchase price. Pipeline capacity cost is calculated for both existing and incremental capacity cost, which includes real growth that varies by scenario. The pipeline commodity charge is a variable cost per million Btu of fuel shipped.

The values used for pipeline delivery and capacity cost are described below. The assumption in the plan is that new power plants are likely to be required to subscribe to incrementally priced pipeline capacity. It was also assumed that these costs would escalate in real terms over time as shown in Table A6-14.

Tables A6-15a and A6-15b show the various transportation components, their column number in the COMPONENTS worksheet, and the current value or range of values in the model. Tables A6-16a and A6-16b show which adjustments are applied to calculate the various industrial and electric utility gas price forecasts from the national wellhead forecast. The “a” tables are for the West side of Oregon and Washington, and the “b” tables are for the East side of Oregon and Washington and Northern Idaho. Estimates for Southern Idaho are based on the Western Oregon and Washington delivery costs (Northwest Pipeline), and Western Montana estimates are based on the Eastern Oregon and Washington delivery costs from AECO.

**Table A6-15a: Natural Gas Delivery Cost from Sumas to West-Side PNW**

| Cost Component | Components Column | Constant Costs (2000$/MMBtu) | Scenario Variant | | | | |
|---|---|---|---|---|---|---|---|
| | | | L | ML | M | MH | H |
| **Pipeline Capacity** | | | | | | | |
| **Firm Rolled-In** | B | $.33 | | | | | |
| **Firm Incremental** | C | $.51 in 2012 + growth | -.1% | .1% | .3% | .5% | .7% |
| **Capacity release** | D | $.28 | | | | | |
| | | | | | | | |
| **Plant Capacity Factor cf** | | 85 Percent | | | | | |
| | | | | | | | |
| **Pipeline Commodity** | E | $.03 | | | | | |
| | | | | | | | |
| **Pipeline Fuel** | $D$42 | 1.99 % | | | | | |
| | | | | | | | |
| **LDS Distribution** | | | | | | | |
| **Firm** | F | $.20 | | | | | |
| **Interruptible Adj.** | K | - $.05 | | | | | |
| | | | | | | | |
| **Firm Supply Premium** | G | 0% | | | | | |
| | | | | | | | |

**Table A6-16a: Cost Adjustments Applied for Specific West-Side Natural Gas Prices.**

| Equation | Natural Gas Product | Calculation |
|---|---|---|
| | | |
| | Industrial Sector | |
| **[1]** | Pipeline Firm | Sumas/(1-D42)+(B/cf+E+G+F)*cd |
| **[2]** | Pipeline Interruptible | Equation[1] + K |
| **[3]** | LDC Served | Wellhead Price + average historical retail difference |
| | | |
| | Utility Sector | |
| **[4]** | Existing Firm | Sumas/(1-D42)+(B/cf+E+G)*cd |
| **[5]** | New Firm | Sumas/(1-D42)+(C/cf+E+G)*cd |
| **[6]** | Interruptible | Equation[4] + K |
| | | |
| | Variable Fuel Costs | |
| **[7]** | New firm e.g. | Sumas/(1-D47)+(E*cd |
| | Fixed Fuel Costs | |
| **[8]** | New firm e.g. | [(f*G)+(C*cd) * hr*8.76/( 1000) |
| | | |
| cd is conversion from 2000$ to year dollars of the forecast (2006$ currently) | | |
| hr is the heat rate of a gas-fired power generation plant | | |
| cf is the capacity factor of a gas-fired power generation plant | | |
| f is the share of fuel supply that is purchase on a firm basis | | |
| | | |

(Capital letters correspond to the Components Column in Table A6-15a.)

The formulas shown in Tables A6-15a and A6-15b may need some translation. For example, equation [5] shows how the incremental cost of firm pipeline capacity on the west side of the region is calculated. It starts with the price at Sumas and increases it to account for the in-kind fuel charge of 1.99 percent on Northwest Pipeline which is contained in cell $D$42. Then the firm incremental pipeline capacity costs (column C) (divided by the capacity factor of the power generating plant), the pipeline commodity charge (column E), and any firm supply premium (column G) are added to the cost. These latter charges are contained in the model in year 2000 dollars so they can be converted to the year dollars chosen for the forecast, in this case, 2006 dollars. The term "cd" is a conversion factor from 2000 to 2006 year dollars. The values in Tables A6-15a and A6-15b have already been converted to 2006 dollars.

The calculation of generator firm incremental natural gas prices is shown a different way in Tables A6-17a and A6-17b.

**Table A6-15b: Natural Gas Delivery Cost from AECO to East-Side PNW**

| Cost Component | Markup Column | Constant Costs (2006$/MMBtu) | Scenario Variant | | | | |
|---|---|---|---|---|---|---|---|
| | | | L | ML | M | MH | H |
| **Pipeline Capacity** | | | | | | | |
| | | | | | | | |
| **Firm Rolled-In** | O | $.32 | | | | | |
| **Firm Incremental** | P | $.47 in 2020 + growth | -.1% | .1% | .3% | .5% | .7% |
| **Capacity Release** | Q | $.33 | | | | | |
| | | | | | | | |
| **Plant Capacity Factor** | | 85 Percent | | | | | |
| | | | | | | | |
| **Pipeline Commodity** | R | $.01 | | | | | |
| | | | | | | | |
| **Pipeline Fuel** | $D$43 | 1.91 % | | | | | |
| | | | | | | | |
| **LDS Distribution** | | | | | | | |
| | | | | | | | |
| **Firm** | S | $.20 | | | | | |
| **Interruptible Adj.** | X | - $.05 | | | | | |
| | | | | | | | |
| **Firm Supply Premium** | T | 0% | | | | | |
| | | | | | | | |

**Table A6-16b: Cost Adjustments Applied for Specific East-Side Natural Gas Prices.**

| Equation | Natural Gas Product | Calculation |
|---|---|---|
| | | |
| | Utility Sector | |
| **[9]** | Existing Firm | AECO/(1-D43)+(O/cf+R+T)*cd |
| **[10]** | New Firm | AECO/(1-D43)+(P/cf+r+t)*cd |
| **[11]** | Interruptible | Wellhead Price + average historical difference |
| | | |
| | Variable Fuel Costs | |
| **[12]** | New firm e.g. | AECO/(1-D43) + R * cd) |
| | Fixed Fuel Costs | |
| **[13]** | New firm e.g. | [(f*T)+(P*cd)]*hr*8.76/( 1000) |
| | | |
| cd is conversion from 2000$ to year dollars of the forecast (2006$ currently) | | |
| hr is the heat rate of a gas-fired power generation plant | | |
| cf is the capacity factor of a gas-fired power generation plant | | |
| f is the share of fuel supply that is purchase on a firm basis | | |

(Capital letters correspond to the Components Column in Table A6-16b.)

**Table A6-71a: Derivation of West-Side Firm Utility Gas Price**
**2006$/MMBtu**

| Medium 11/21/2008 | Derivation of West-Side Firm Utility Gas Price 2006$/MMBtu | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | US Wellhead Price | Henry Hub Price | Sumas Delta | Sumas Price | Firm Supply Premium | Pipeline Fuel Charge | Incremental Transport Cost | Pipeline Commodity Charge | Utility Gas Price | Total Delivery Cost |
| | | | (+) | | (+) | (+) | (+) | (+) | | |
| 2005 | 7.36 | 7.95 | -0.87 | 7.08 | 0.00 | 0.14 | 0.45 | 0.03 | 7.70 | 0.63 |
| 2006 | 6.23 | 6.72 | -0.77 | 5.95 | 0.00 | 0.12 | 0.45 | 0.03 | 6.56 | 0.60 |
| 2007 | 6.06 | 6.53 | -0.75 | 5.78 | 0.00 | 0.12 | 0.45 | 0.03 | 6.38 | 0.60 |
| 2008 | 7.83 | 8.51 | -0.43 | 8.09 | 0.00 | 0.16 | 0.49 | 0.03 | 8.77 | 0.69 |
| 2009 | 6.50 | 7.70 | -0.36 | 7.34 | 0.00 | 0.15 | 0.55 | 0.03 | 8.07 | 0.73 |
| 2010 | 6.75 | 7.32 | -0.32 | 7.00 | 0.00 | 0.14 | 0.62 | 0.03 | 7.79 | 0.79 |
| 2011 | 6.80 | 7.38 | -0.33 | 7.05 | 0.00 | 0.14 | 0.69 | 0.03 | 7.91 | 0.86 |
| 2012 | 6.85 | 7.43 | -0.33 | 7.10 | 0.00 | 0.14 | 0.70 | 0.03 | 7.97 | 0.88 |
| 2013 | 6.90 | 7.48 | -0.34 | 7.15 | 0.00 | 0.15 | 0.70 | 0.03 | 8.03 | 0.88 |
| 2014 | 6.95 | 7.54 | -0.34 | 7.20 | 0.00 | 0.15 | 0.70 | 0.03 | 8.08 | 0.88 |
| 2015 | 7.00 | 7.60 | -0.35 | 7.25 | 0.00 | 0.15 | 0.71 | 0.03 | 8.14 | 0.88 |
| 2016 | 7.05 | 7.65 | -0.35 | 7.30 | 0.00 | 0.15 | 0.71 | 0.03 | 8.19 | 0.89 |
| 2017 | 7.10 | 7.71 | -0.36 | 7.35 | 0.00 | 0.15 | 0.71 | 0.03 | 8.24 | 0.89 |
| 2018 | 7.15 | 7.76 | -0.36 | 7.40 | 0.00 | 0.15 | 0.71 | 0.03 | 8.29 | 0.89 |
| 2019 | 7.20 | 7.82 | -0.36 | 7.45 | 0.00 | 0.15 | 0.71 | 0.03 | 8.35 | 0.90 |
| 2020 | 7.25 | 7.87 | -0.37 | 7.50 | 0.00 | 0.15 | 0.72 | 0.03 | 8.40 | 0.90 |
| 2021 | 7.30 | 7.93 | -0.37 | 7.55 | 0.00 | 0.15 | 0.72 | 0.03 | 8.46 | 0.90 |
| 2022 | 7.35 | 7.98 | -0.38 | 7.60 | 0.00 | 0.15 | 0.72 | 0.03 | 8.51 | 0.91 |
| 2023 | 7.40 | 8.04 | -0.38 | 7.65 | 0.00 | 0.16 | 0.72 | 0.03 | 8.56 | 0.91 |
| 2024 | 7.45 | 8.09 | -0.39 | 7.70 | 0.00 | 0.16 | 0.73 | 0.03 | 8.62 | 0.91 |
| 2025 | 7.50 | 8.15 | -0.39 | 7.75 | 0.00 | 0.16 | 0.73 | 0.03 | 8.67 | 0.92 |
| 2026 | 7.60 | 8.26 | -0.40 | 7.85 | 0.00 | 0.16 | 0.73 | 0.03 | 8.77 | 0.92 |
| 2027 | 7.70 | 8.36 | -0.41 | 7.95 | 0.00 | 0.16 | 0.73 | 0.03 | 8.88 | 0.92 |
| 2028 | 7.80 | 8.48 | -0.42 | 8.05 | 0.00 | 0.16 | 0.73 | 0.03 | 8.98 | 0.93 |
| 2029 | 7.90 | 8.59 | -0.43 | 8.15 | 0.00 | 0.17 | 0.74 | 0.03 | 9.09 | 0.93 |
| 2030 | 8.00 | 8.70 | -0.44 | 8.26 | 0.00 | 0.17 | 0.74 | 0.03 | 9.19 | 0.94 |

**Table A6-17b: Derivation of East-Side Firm Utility Gas Price**
**2006$/MMBtu**

| | Derivation of East-Side Firm Utility Gas Price | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2006$/MMBtu | | | | | | | |
| | AECO Delta | AECO Price | Firm Supply Premium | Pipeline Fuel Charge | Incremental Transport Cost | Pipeline Commodity Charge | Utility Gas Price | Total Delivery Cost |
| | (+) | | (+) | (+) | (+) | (+) | | |
| 2005 | -0.97 | 6.98 | 0.00 | 0.13 | 0.45 | 0.01 | 7.57 | 0.60 |
| 2006 | -0.88 | 5.84 | 0.00 | 0.11 | 0.45 | 0.01 | 6.41 | 0.57 |
| 2007 | -0.87 | 5.67 | 0.00 | 0.11 | 0.45 | 0.01 | 6.24 | 0.57 |
| 2008 | -1.08 | 7.44 | 0.00 | 0.14 | 0.45 | 0.01 | 8.04 | 0.61 |
| 2009 | -0.99 | 6.71 | 0.00 | 0.13 | 0.48 | 0.01 | 7.33 | 0.62 |
| 2010 | -0.95 | 6.37 | 0.00 | 0.12 | 0.52 | 0.01 | 7.02 | 0.65 |
| 2011 | -0.96 | 6.42 | 0.00 | 0.12 | 0.56 | 0.01 | 7.11 | 0.70 |
| 2012 | -0.96 | 6.47 | 0.00 | 0.12 | 0.62 | 0.01 | 7.22 | 0.75 |
| 2013 | -0.97 | 6.52 | 0.00 | 0.12 | 0.62 | 0.01 | 7.27 | 0.75 |
| 2014 | -0.97 | 6.57 | 0.00 | 0.13 | 0.62 | 0.01 | 7.32 | 0.75 |
| 2015 | -0.98 | 6.62 | 0.00 | 0.13 | 0.62 | 0.01 | 7.37 | 0.75 |
| 2016 | -0.99 | 6.66 | 0.00 | 0.13 | 0.63 | 0.01 | 7.43 | 0.77 |
| 2017 | -0.99 | 6.71 | 0.00 | 0.13 | 0.63 | 0.01 | 7.48 | 0.77 |
| 2018 | -1.00 | 6.76 | 0.00 | 0.13 | 0.64 | 0.01 | 7.55 | 0.78 |
| 2019 | -1.00 | 6.81 | 0.00 | 0.13 | 0.64 | 0.01 | 7.60 | 0.79 |
| 2020 | -1.01 | 6.86 | 0.00 | 0.13 | 0.64 | 0.01 | 7.65 | 0.79 |
| 2021 | -1.02 | 6.91 | 0.00 | 0.13 | 0.65 | 0.01 | 7.70 | 0.79 |
| 2022 | -1.02 | 6.96 | 0.00 | 0.13 | 0.65 | 0.01 | 7.75 | 0.79 |
| 2023 | -1.03 | 7.01 | 0.00 | 0.13 | 0.65 | 0.01 | 7.80 | 0.79 |
| 2024 | -1.03 | 7.06 | 0.00 | 0.13 | 0.65 | 0.01 | 7.86 | 0.80 |
| 2025 | -1.04 | 7.11 | 0.00 | 0.14 | 0.65 | 0.01 | 7.91 | 0.80 |
| 2026 | -1.05 | 7.21 | 0.00 | 0.14 | 0.66 | 0.01 | 8.01 | 0.80 |
| 2027 | -1.06 | 7.30 | 0.00 | 0.14 | 0.66 | 0.01 | 8.11 | 0.81 |
| 2028 | -1.07 | 7.40 | 0.00 | 0.14 | 0.66 | 0.01 | 8.21 | 0.81 |
| 2029 | -1.08 | 7.50 | 0.00 | 0.14 | 0.66 | 0.01 | 8.32 | 0.82 |
| 2030 | -1.10 | 7.60 | 0.00 | 0.15 | 0.66 | 0.01 | 8.42 | 0.82 |

### *Fixed and Variable Natural Gas Costs*

The Council's resource planning models require utility gas prices in terms of their fixed and variable components. For the Pacific Northwest, the model forecasts these based on the components described in Table A6-17a and A6-17b. Natural gas prices at regional hubs, pipeline fuel costs, and pipeline commodity charges are variable costs. That is, they can be avoided if electricity is not generated. The major fixed cost for natural gas is the pipeline reservation charge. It accounts for most of the transportation cost of natural gas. The pipeline reservation cost is divided by the plants capacity factor, currently set to .85, to get the correct cost per million Btu of fuel consumed. The other fixed cost is any premium that must be paid to secure firm gas supply. This is currently set to zero in the forecasts. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

The forecasts of natural gas prices to electric generators outside of the Pacific Northwest also have to be expressed in terms of fixed and variable costs. However, for these areas to forecasting approach does not explicitly include the components relied on to calculate the Pacific Northwest fixed and variable costs. The natural gas prices in these areas relied on either estimated equations of relationships to pricing hubs, or on average differences in costs observed historically. However, these differences include more than just pipeline transportation costs. Some differences for example are negative reflecting various market forces. A different approach is required in these cases.

To calculate the fixed and variable components of the non-PNW a little different assumption had to be made. In order to simplify the process, and not end up with zero capital costs for regions with state electric generators prices lower than hub prices, it was assumed that the fixed costs of pipeline capacity was the same for all areas. For existing generators, it was assumed to be $.50. For incremental generators is was assumed to be $.62, escalating at the scenario varying rates shown in Table A6-14.

### *Retail Prices*

Residential and commercial sector retail natural gas prices are based on historical 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, or markups, can be projected from historical trends, other forecasting models, or judgement.

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 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 markup 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 for four areas of the Northwest are developed in the worksheet COMPONENTS.

To forecast the firm and interruptible prices for industrial gas users that secure their own supplies and transportation, calculations similar to those for power generators are used. Industrial firm gas users have been assumed to pay rolled-in rates. Interruptible users pay interruptible pipeline capacity charges. It is also assumed that industrial users will have to pay either firm or interruptible distribution charges to a local gas distribution company. As discussed above, gas prices for industrial gas users that obtain their gas supplies through their local distribution company can be forecast from national wellhead prices and historical relationships to reported retail prices. All of the specific adjustments that are applied to the other industrial and utility users are captured implicitly by this method.

## *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[7]. Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding markups 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 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 dollars.
- Saudi light yields 47 % heavy oil.
- 3 percent energy penalty.

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

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

Profit Equations:

<u>Simple refinery</u>

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.

[7] 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.

L is distillate oil wholesale price.
C is cost of crude oil
.03 is the energy penalty for simple refining.
2.15 is the refining cost per barrel.

<u>Complex refinery</u>

Revenue = L
Cost = C + .12C + 5.38
Profit = L - (C + .12C + 5.38)

<u>Equilibrium Condition:</u> Profit from heavy products equals profit from light products at the margin.

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

<u>Solve for product prices:</u>

$$.47H + .53L - L = .03C - .12C - 5.38 + 2.15$$
$$.47(H - L) = -.09C - 3.23$$
$$(H - L) = -.1915C - 6.8723$$

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 (in 2000 dollars) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based markups are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices and 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 consists of two tabs in FUELMOD7(1). One tab calculates total coal costs at various locations in the West. A second tab calculates only the variable costs of coal for electricity generation.

Coal costs delivered to the Northwest, for example, are based on PRB minemouth prices with delivery costs added. PRB minemouth price forecasts are based on the last year of available prices, adjusted to an estimated trend level starting point a few years into the forecast period. These trend levels vary by forecast case. Once estimated trend levels are reached a simple annual real price growth rate is added, which also varies by forecast case.

Total delivered costs are estimated for industrial coal users in the Northwest, and for electricity generation in various areas of the West. Industrial prices are based on historical differences between Northwest industrial coal prices and PRB minemouth prices. In the forecast these differences are escalated for diesel fuel cost increases. Electricity generation coal costs are estimated for areas in WECC based on distance from the PRB, unit car rail costs per ton-mile, and an escalation factor for diesel fuel costs.

Currently the coal prices are forecast in 2000 constant dollars. The prices in the COALFC tab are entered in 2000 dollars, and the regional coal prices are estimated in 2000 dollars and then converted to the year dollars of the other forecasts. In the Sixth Power Plan these are 2006 constant dollars.

# ATTACHMENT A6-1

## --GUIDE TO FUEL PRICE FORECASTING MODEL PAGES

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**DOC-** -- -Describes files in the forecast model
--
**Deflation-** -- -The Deflation worksheet contains implicit GDP deflators and uses them to generate a series of conversion factors to convert from nominal to 2000 dollars. It is set up to enter the year-dollars the user wants the model to work in and creates a conversion factor (cd) to convert from 2000$ to the chosen year dollars. It also creates labels that are put in various places in the model to reflect the year dollars being used.
--
**NGFC-** ---Contains historical wellhead natural gas prices in various units, and the forecast range of wellhead prices. The forecast of natural gas prices must be done in the year dollars chosen for the reports in the Deflation tab. The forecasts, as well as oil and coal forecasts, are developed in a separate spreadsheet called "Fuel Price FC Develop 090308.xls".
--
**WOPFC-** ---Contains historical world oil prices in various units, and the forecast range of world oil prices. The world oil prices are defined as refiners acquisition prices of imported oil. As in the case of the wellhead gas price forecast, the forecast of world oil prices must be done in the year dollars chosen for the reports in the Deflation tab.
--
**COALFC-**---Contains forecasts of Wyoming/Montana fuel prices for a short historical period and low through high forecasts for prices. Coal price forecasts, unlike natural gas and oil, must be done in year 2000 dollars.
--
**MAIN-** -- -MAIN is where most of the controls for a forecast run are set. Cell B2 contains a drop down menu for choice of the forecast scenario. When the user picks a scenario, the worksheet inserts the appropriate natural gas, oil, and coal prices from the NGFC, WOPFC, and COALFC tabs. Cell E3 contains the run date. At the bottom of the worksheet, is a section where scenario varying parameters are chosen to fit the scenario. The right side of the worksheet contains a summary of burner-tip prices for oil, natural gas, and coal.
--
**NG West Annual-** ---This worksheet develops forecasts of natural gas prices at various pricing points throughout the West. The major pricing hubs (orange highlights) are averages of values calculated in the NG West Monthly tab. Equations then relate annual major hub prices to prices in specific WECC locations. The year dollars are automatically adjusted in this worksheet, including changes to the parameters in the basis equations.
--
**Basis Equations**----This tab contains econometric relationship among natural gas pricing hubs at Henry Hub and various points in the West. It includes an equation to convert annual wellhead prices to monthly wellhead prices, and an equation to estimate monthly Henry Hub prices based on the monthly wellhead price forecast. It includes assumed values for differentials where equations are not estimated
--
**NGWest Monthly**----This tab creates monthly Hub prices from the U.S. wellhead price forecast using the equations in the Basis Equations tab.
--
**COMPONENTS**----This worksheet develops delivered natural gas prices for Pacific Northwest large users. The delivery costs are built up from shipping cost components. Price estimates are developed for firm and interruptible customers, and for existing and new customers. New customers are expected to pay incremental pipeline capacity costs. These delivered prices are developed separately for the West and East sides of the PNW.

--
**HistRetail-**---This contains historical prices for retail natural gas and oil products. The prices run from 1980 to 2005. These prices are used to calibrate markups from wholesale fuel prices to retail prices by sector (used in RES_COM, INDUST, and OILMOD) for input to the demand forecasting models.
--
**RES_COM-** -- -This sheet calculates Residential & Commercial retail natural gas prices for the residential and commercial sectors. Retail prices are estimated from wholesale prices using markup assumptions that come from the HistRetail worksheet
--
**INDUST-** -- -This sheet calculates delivered industrial natural gas prices for industrial consumers. It includes estimates for direct purchasers from the pipeline, both firm and interruptible, and also for industrial users that purchase from the LDC (Local Distribution Company).
--
**NWUTIL-** -- -This worksheet develops natural gas prices for electric generators in four subareas of the PNW. There are estimates for Existing firm supplies, for new incremental supplies, and for interruptible supplies. The costs are separated into fixed and variable costs using the components contained in the COMPONENTS worksheet.
--
**Aurora Monthly**- -- -Develops monthly fixed and variable natural gas prices for electric generators at Aurora Model pricing points throughout the West (WECC).
--
**C$ NWUtil-** -- -This sheet displays the derivation of utility delivered natural gas prices. It is more easily understood than the NWUTIL sheet.
--
**GASSUM-** ---Summary table for gas price forecasts, linked to the individual
-- sector worksheets.
--
**OILMOD-** ---The oil model estimates refiner cost of residual and distillate products based on the refiner acquisition cost of imported oil from the WOPFC worksheet. The refiner product prices are based on a very simple profit maximization model of refiner operations. The worksheet goes on to estimate sectoral retail prices for distillate and residual oil based on markups from the historical relationships in the HistRetail worksheet.
--
**OilSum**----This sheet contains a summary of the oil price forecasts.
--
**COAL(Total)**- ---This sheet contains a coal price forecasting model. The basic forecast of price is for PRB minemouth price, which is simply based on alternative growth rates that are specified for each forecast case in the MAIN tab. The model then calculates delivered coal prices for each Western Aurora model region. Delivered prices are based on a standard cost per ton-mile of commodity using a unit train, combined with the estimated number of miles from mine mouth to an particular area. The percent change in diesel prices weighted by the share share of delivery cost that is due to the propulsion energy requirements (25%), adjusts the delivery costs so that they roughly reflect changes in oil prices.
--
**COAL(Variable)**----Same as COAL(Total) except that only includes variable delivery costs.
--
**Tables**--Develops tables to be included in forecast document appendices
--
**Graphs**--Miscellaneous graphs to assess the forecast and describe results
--
NOTE: Columns with Red block at top need to be input during forecast period.
--

# Appendix B: Economic Forecast


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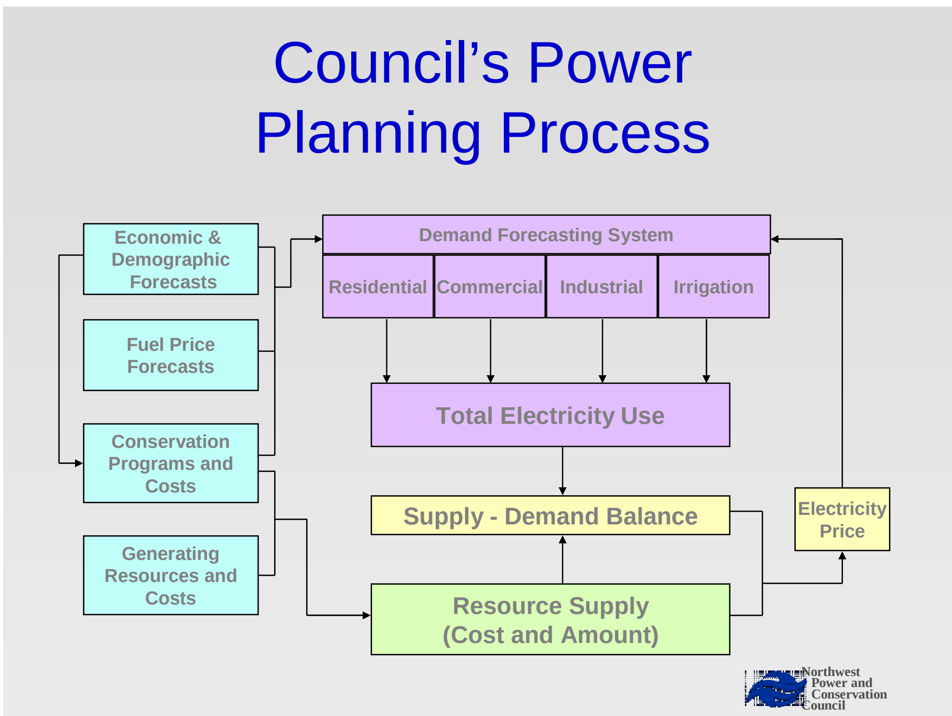
## ROLE OF THE ECONOMIC FORECAST

A 20-year forecast of demand for electricity is one of the requirements of the Northwest Power Act (Public Law 96-501, Sec. 4(e)(3)(D) ). A detailed demand forecast is used in planning future conservation potential, electricity market clearing price projections, as well as in the Council's own resource risk assessments. To better capture the impact of future uncertainties, the Council develops a forecast of future demand for energy that identifies not just one trend but a range of trends. The demand forecast range is determined by a consistent set of assumptions about uncertainties in future economic and demographic activities in the region, the trajectory of fossil fuel and electricity prices, and legislative and market responses to climate change.

The figure below depicts the Council's power planning process. The planning process starts with economic and demographic assessments and then adds fuel and electricity price forecasts to create a forecast for electricity demand. The demand forecast looks at energy use by sector to predict monthly load for electricity generators. The Northwest load forecast, along with the forecast for load outside the Northwest, is used in forecasting wholesale electricity prices. Northwest load is used in the Council's Regional Portfolio Model (RPM) to create least-cost, low-risk resource options for the region.

The demand forecast is also used extensively to develop the conservation supply curves. The key economic drivers for the conservation supply curves are identical to the economic drivers of the demand forecast.




# BACKGROUND

## *Economic Growth Assumptions*

The national economic models driving the regional forecast of the Sixth Power Plan were updated as of the first quarter 2009. Given the long-term nature of the Council's power plan, the current recession and impact of the federal economic stimulus package were not modeled in detail. However, pace of economic activity was reduced to capture the impact of recession on energy consumption. Also, over the next 20 years, economic policy initiatives responding to climate change will affect the regional economy and regional demand for energy. These policy changes have not been explicitly incorporated into the Council's economic assumptions or demand forecast for electricity.

Many things determine the load forecast, and energy demand is influenced by both long-term and short-term factors.  Long-term variables may be economic circumstances, life-style choices, demographic changes, or socio-economic trends that take decades to develop and fade.  Energy demand is also affected by short-term factors, such as weather conditions or changes in income. The combination of all these conditions determines the demand for energy.

# ECONOMIC DRIVERS OF RESIDENTIAL DEMAND

The number of dwellings is a key driver of energy demand in the residential sector.  Residential demand begins with the number of units, including single family, multifamily, and manufactured homes.  This demand is forecast to grow at 1.3 percent annually from 2010-2030.  The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

Another factor affecting residential demand for electricity is life-style trends.  As more homes are linked to the internet and the saturation rate for air-conditioning appliances and electronic equipment increases, demand for electricity in the residential sector increases.  Over 80 percent of all new homes in the region now have central air conditioning.  This compares to 7-8 percent of housing stock with central air conditioning in the 1980s.  Another change is the growth rate in home electronics, which has been phenomenal at over 6 percent per year since 2000, and which is expected to continue to increase.

In the residential sector, electricity demand is driven by space heating and cooling, as well as refrigeration, cooking, washing, and a new category called Information, Communication and Entertainment (ICE).  This new category includes all portable devices that must be charged, such as laptop computers and cell phones, as well as larger, more energy-intensive televisions and gaming devices.  As the regional population grows, and with it the number of homes, demand for these services and appliances will also increase.  The energy efficiency of appliances as dictated by state and federal standards, which appliances consumers buy, and how they use them, affect energy demand, as well.

The “number of homes” category is driven by regional population, house size, and composition of the population.  The region’s population increased from about 8.9 million in 1985 to about 13 million by 2007, and is projected to grow to over 16.7 million by 2030 at an annual rate of 1.2 percent.

The following figure reflects the expected population change in each of the four states.

**Figure B-1: Population Forecast (000)**

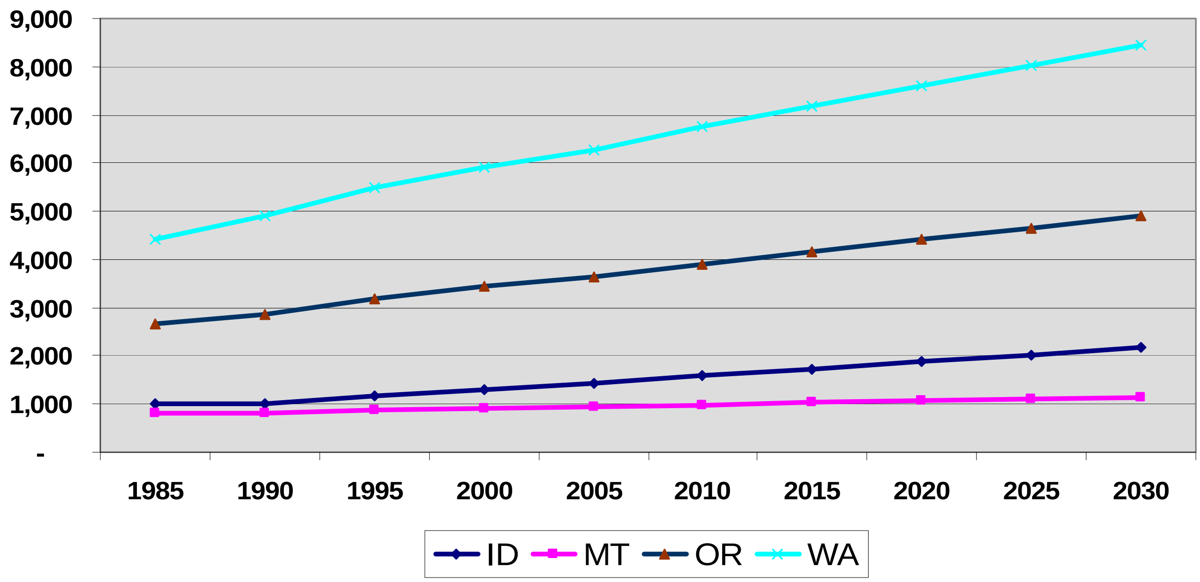



**Table B-1: Population in the Region (000)**

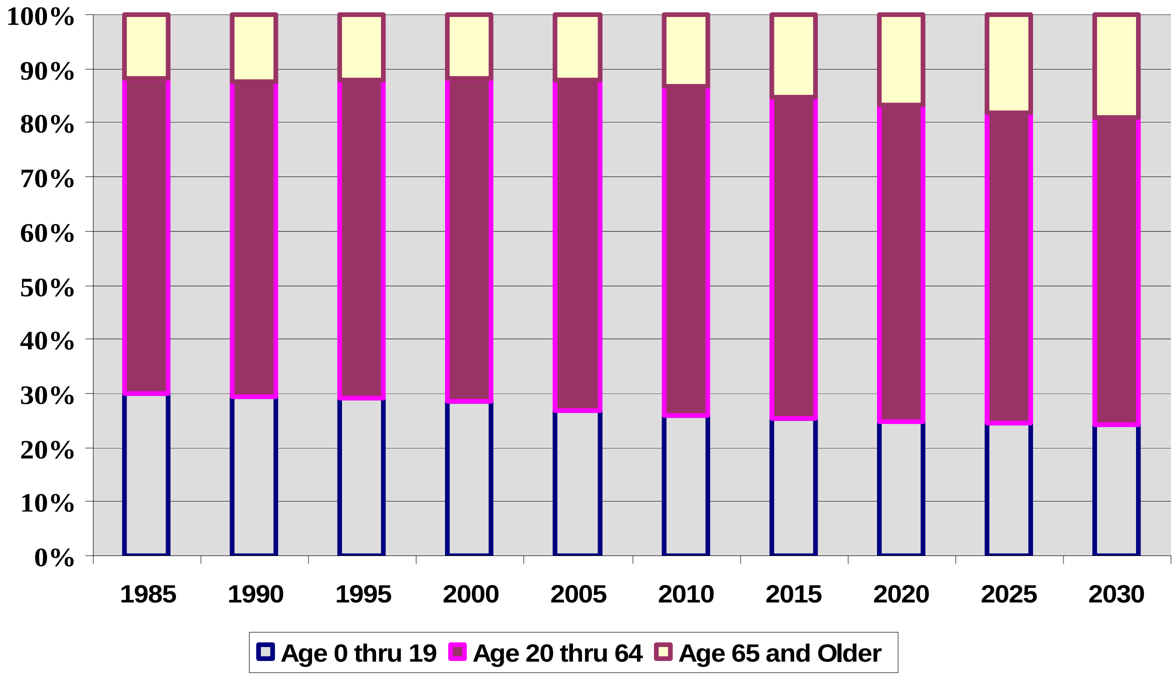
| State | 1985 | 2007 | 2010 | 2015 | 2030 | Annual Growth rates[1] | |
|---|---|---|---|---|---|---|---|
| | | | | | | 1985-2007 | 2010-2030 |
| **ID** | 993 | 1,504 | 1,584 | 1,731 | 2,180 | 1.9% | 1.6% |
| **MT** | 821 | 959 | 990 | 1,038 | 1,153 | 0.7% | 0.8% |
| **OR** | 2,674 | 3,754 | 3,905 | 4,162 | 4,902 | 1.6% | 1.1% |
| **WA** | 4,406 | 6,480 | 6,750 | 7,180 | 8,449 | 1.8% | 1.1% |
| **4 states** | 8,894 | 12,698 | 13,229 | 14,110 | 16,685 | 1.6% | 1.2% |

**Table B-2: Composition of Regional Population (000)**

| | 1985 | 2007 | 2010 | 2015 | 2030 |
|---|---|---|---|---|---|
| **Population Age 0 thru 19** | 2,673 | 3,353 | 3,432 | 3,568 | 4,059 |
| **Population Age 20 thru 64** | 5,161 | 7,747 | 8,056 | 8,402 | 9,443 |
| **Population Age 65 & Older** | 1,060 | 1,562 | 1,741 | 2,140 | 3,183 |

[1] Important note: This appendix uses average annual growth rates as summary figures when comparing the historic and forecast periods for many economic drivers and fuel prices. The average annual growth rate is sensitive to the base year values used in calculating the annual growth rates. For a more accurate picture of the year-by-year growth in economic drivers and prices, additional information for each state is available from the companion Excel worksheet available from Council's website. This companion data can provide a more accurate picture of historic and future growth.

**Figure B-2: Composition of Population Forecast (000)**




## *Population*

The region's population is changing and reflects demographic shifts seen throughout the United States. In 1985, 30 percent of the region's population was younger than 19. This age group has been growing at about 1 percent per year, but it is forecast to grow more slowly for the next two decades, at around 0.7 percent annually. As a percentage of the total population, it is projected to represent about 24 percent of the population by 2030. This generation represents consumers who have grown up with ICE technologies, the fastest-growing segment of residential electricity demand.

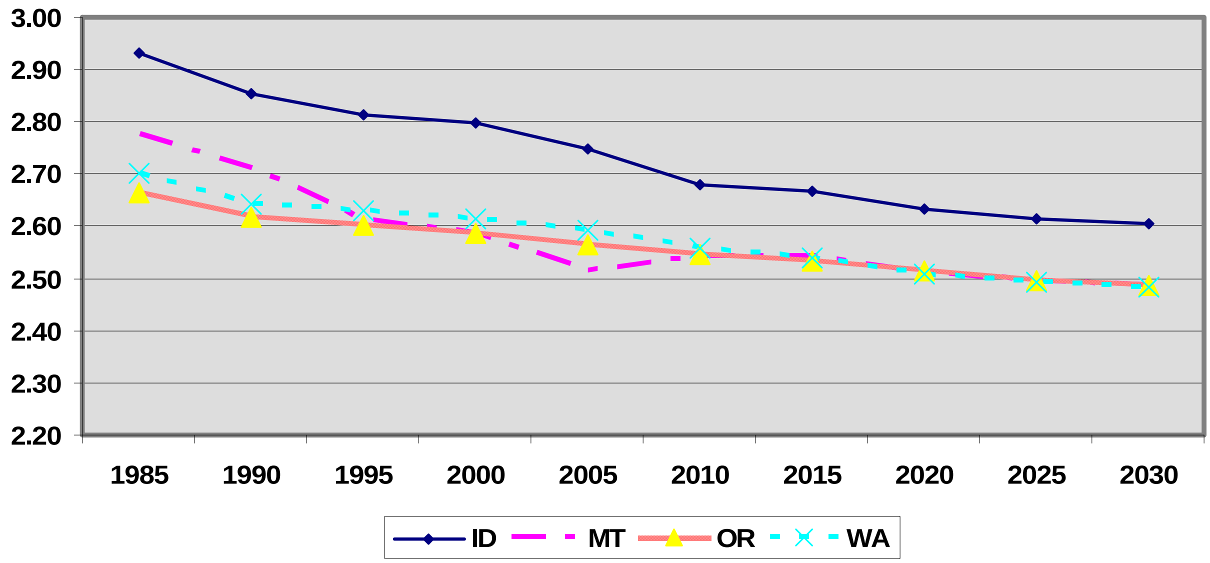
The 20-to-64 year-old age group, representing the working group, has grown from about 5 million in 1985 to about 7.7 million in 2007, and is projected to grow to over 9 million by 2030. This age group has been growing at 1.9 percent per year, but its growth rate is expected to be significantly reduced as more and more baby boomers retire. This demographic category plays a critical role in regional employment, demand for homes, major capital equipment, and goods and services.

The fastest-growing population segment is people over 64, the "retirees." They represented about 12 percent of the population in 1985, and by 2030 they are expected to represent about 20 percent of the region's population. This segment is expected to grow almost 3 percent per year over the next 20 years, at almost three times the growth rate of the total population. This trend has affected the commercial sector in many ways, and the increase in the number of businesses catering to elders is one example. In 2005, the Bureau of Labor Statistics and county business patterns show there were over 3,200 businesses in the region offering elder care services. Such businesses had more than 100,000 employees and occupied about 60 million square feet of space.  If the current trends continue, by 2030 an additional 50 million square feet of space would be needed for elder care.  The demand from this business is tracked in the commercial section of the model.  However, the region lacks a good understanding of the demand from this particular market segment, so the Sixth Power Plan recommends pursuing better data on the energy consumption pattern of this sector.

## *Housing Stock*

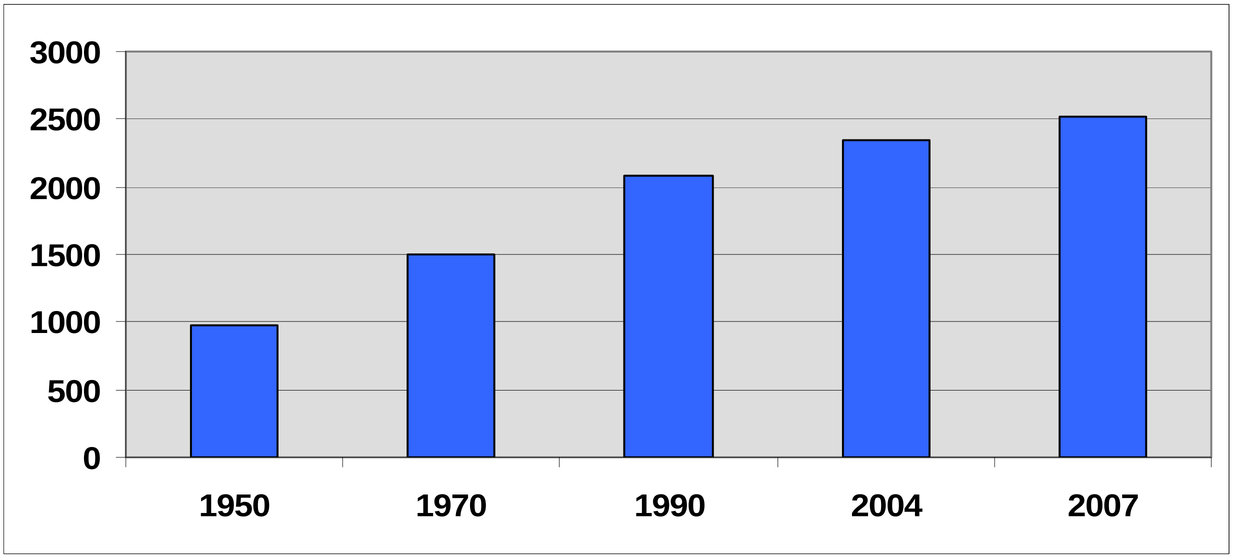
While the regional population has been increasing, the number of occupants per household has been declining.  In 1985, the average household size was about 2.95 persons per household, and by 2030 it is expected to go down to 2.6 persons per household, resulting in the number of homes growing at a faster rate than the population.

**Figure B-3:  Declining Household Size (People per Household)**




While the number of occupants per household has declined, the square footage of homes has been increasing. According to the U.S. Bureau of Census's annual survey of new homes, the average single-family house completed in 2007 had 2,521 square feet, 801 more square feet than homes in 1977.  Going back to the 1950s, the average square footage of a new single-family home was about 983 square feet.  Over the past five decades, the average home size has grown by more than 250 percent.  In 2007, 38 percent of new single-family homes had four or more bedrooms, almost twice the number of bedrooms in most homes built 20 years ago.  In addition, 90 percent of these new homes had air conditioning.  These changes have meant an increased demand for space conditioning and lighting.

**Figure B-4:  Growing Average Size of New Single Family Homes**




The increase in the average size of homes has not been limited to single-family residences.  The average square footage of multi-family units completed and built for sale in 2007 was 1,577 square feet, 217 square feet more than in 1999.  It is difficult to predict the future trends in house size.  However, if the movement toward a more sustainable lifestyle gains momentum, housing size may decline as the number of single-occupant households increases and the population ages.

In absolute terms, the number of single-family housing has been growing at a faster pace than the overall population.  Between 1985 and 2007, the population grew at 1.6 percent per year and the number of homes grew at 1.9 percent per year.  As incomes increased and as more people purchased homes, the number of households grew at a rate faster than the rate of population growth.

**Figure B-5: Number of Single-Family Homes (000) Stock**

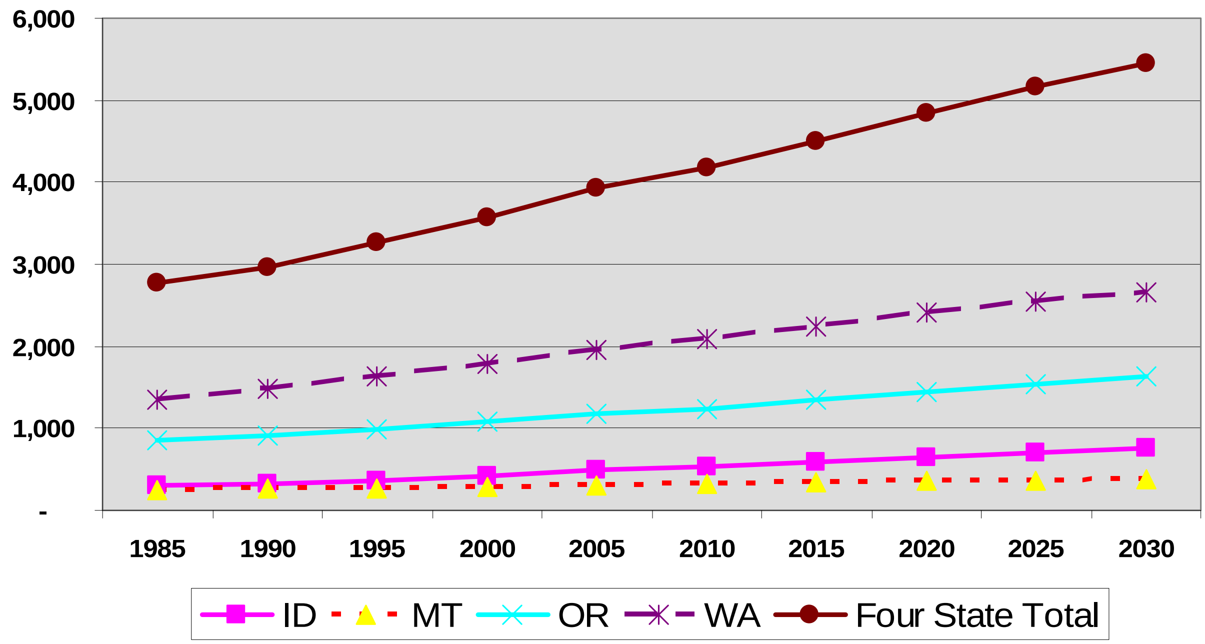
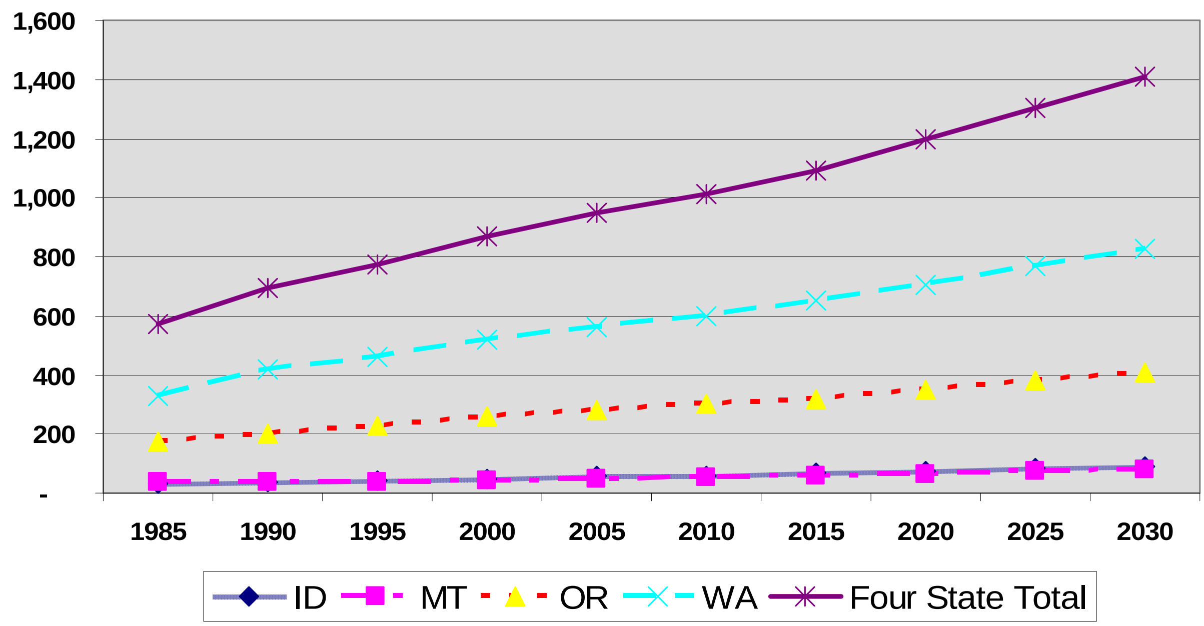
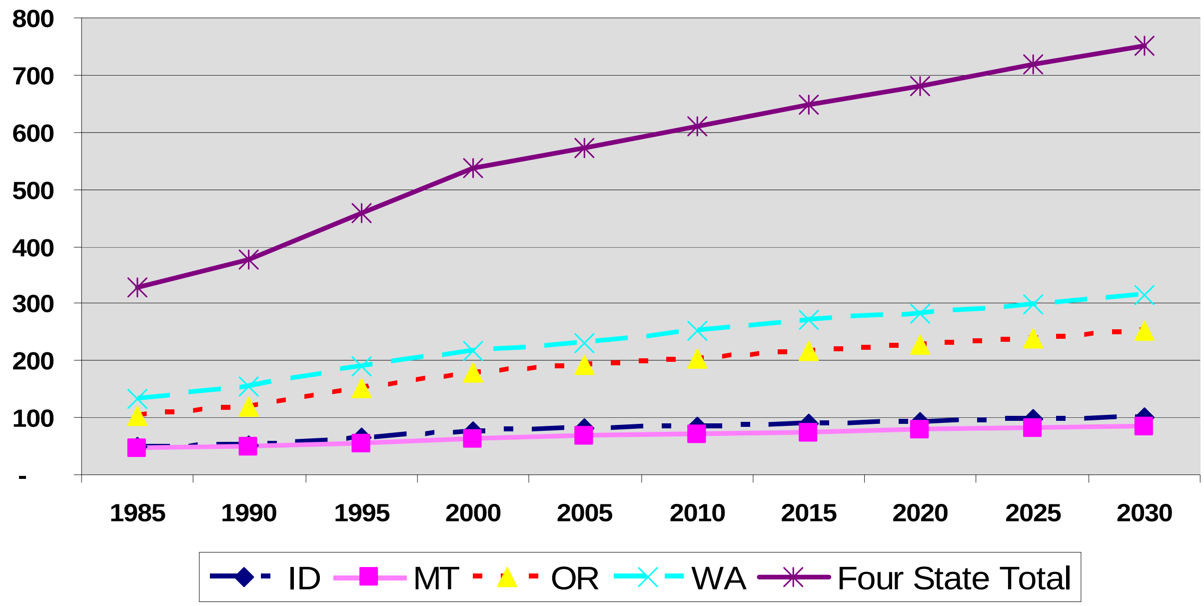



**Figure B-6: Number of Multi-Family Homes (000) Stock**



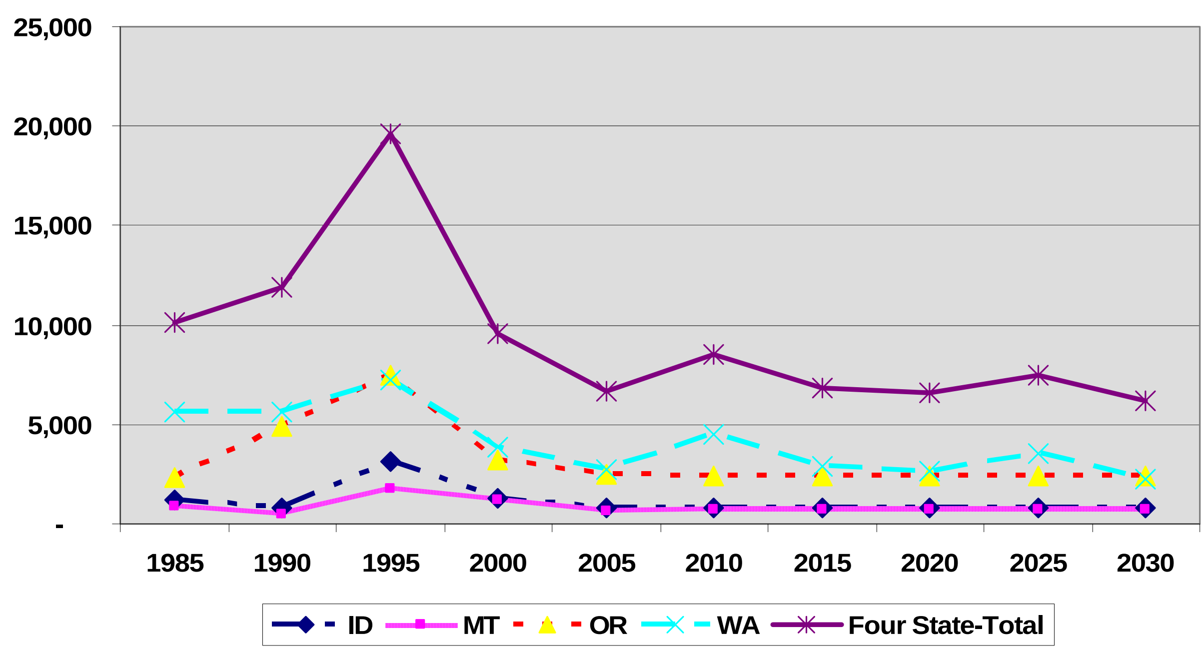

A housing sub-sector that has not been growing as fast is manufactured housing. The factors determining demand for this type of housing are income, price of land, and the number of newlywed and low-income populations. Manufactured homes tend to be less-expensive housing options, so an increase in per capita income in the region has slowed demand for these homes. The price of manufactured housing has also increased, although significantly less than stick-built homes.

**Figure B-7: Number of Manufactured Homes (000) Stock**




Although manufactured housing typically represents about 10 percent of new homes in the region, they represent about 30 percent of electrically heated new homes. Recognizing this high percentage of electrically heated homes, the Manufactured Housing Acquisition Program was established in 1992. The incentive program, supported by the Council, the Bonneville Power Administration, state energy offices, electric utilities, and manufacturers, paid manufacturers the incremental cost to add efficiency measures to each new home. New manufactured homes peaked in 1995 after this program ended. For now, the stock of manufactured homes is projected to increase, although at a slower rate.

**Figure B-8: New Manufactured Homes per Year**



The overall composition of housing stock has been changing to favor multi-family homes. Single-family homes (defined as a detached single-family home or a multi-plex unit of up to 4 units) has been losing market share. Single-family homes represented 75 percent of homes in the region in 1985, but by 2007 they represented 72 percent of housing stock. By 2030, the forecast is for single-family homes to decline to about 71 percent. Multi-family homes (defined as housing with greater than four units) represented 16 percent of residential housing stock in 1985, 17 percent by 2007, and is projected to be about 20 percent by 2030. Manufactured homes have had a 9-10 percent market share and are projected to retain this status.

**Table B-3: Average Annual Number of New Homes**

| | 1985-2000 | 2001-2008 | 2010-2030 |
|---|---|---|---|
| **Single-Family** | | | |
| **Idaho** | 7,390 | 12,573 | 11,575 |
| **Montana** | 2,070 | 3,616 | 3,038 |
| **Oregon** | 14,459 | 17,786 | 19,379 |
| **Washington** | 28,237 | 32,311 | 28,710 |
| **Four State Total** | 52,157 | 66,286 | 62,701 |
| **Multi-Family** | | | |
| **Idaho** | 901 | 1,417 | 1,466 |
| **Montana** | 551 | 988 | 1,384 |
| **Oregon** | 5,660 | 4,524 | 5,361 |
| **Washington** | 12,762 | 9,216 | 11,146 |
| **Four State Total** | 19,873 | 16,146 | 19,357 |
| **Manufactured Home** | | | |
| **Idaho** | 1,818 | 870 | 837 |
| **Montana** | 1,161 | 775 | 714 |
| **Oregon** | 4,983 | 2,424 | 2,404 |
| **Washington** | 5,609 | 3,138 | 3,157 |
| **Four State Total** | 13,571 | 7,208 | 7,111 |

Each year during 1985-2008, an average of 54,000 new single-family, 19,500 multi-family, and 12,000 new manufactured homes were added to the existing stock. Starting in 2000, each year has seen a dramatic increase in new single-family home additions. Rising income levels in the region and the increased availability of credit caused a shift from multi-family to single-family home ownership. In 2005, more than 87,000 new single-family homes were added in the region. This increase in the number of single-family houses caused a substantial increase in the price of housing. In the 2010-2030 period, the Council anticipates a return to more historic levels of growth. A slow down in new single-family home additions is already evident. The forecast predicts an increase in multi-family homes in the region. The impact of the current recession on new residential construction was incorporated in the revised forecast using Global Insight's short-term economic forecast of October 2009.

**Figure B-9: New Single Family Home Additions**

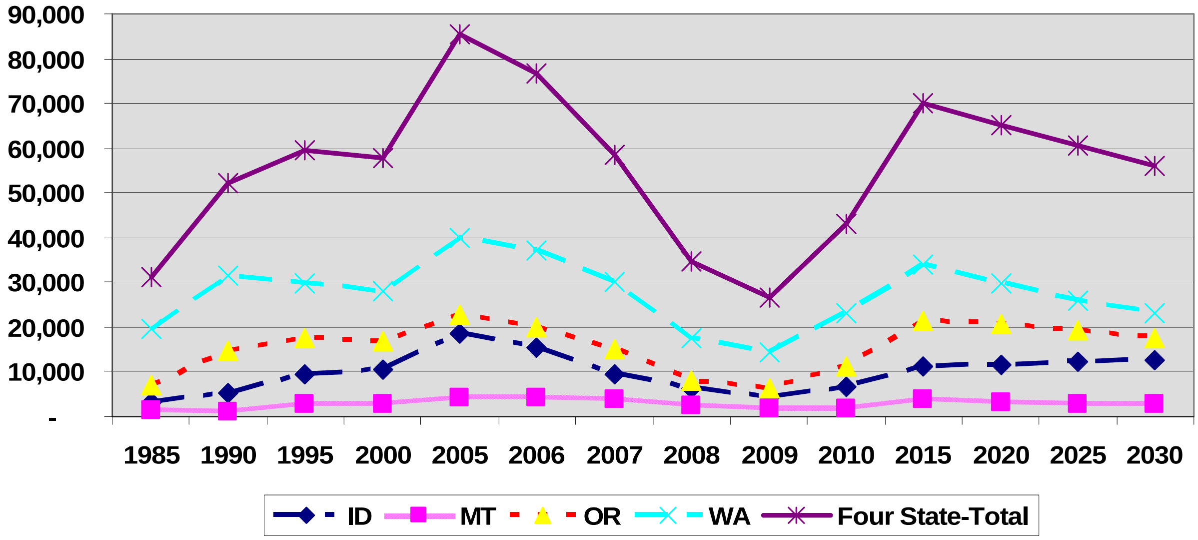
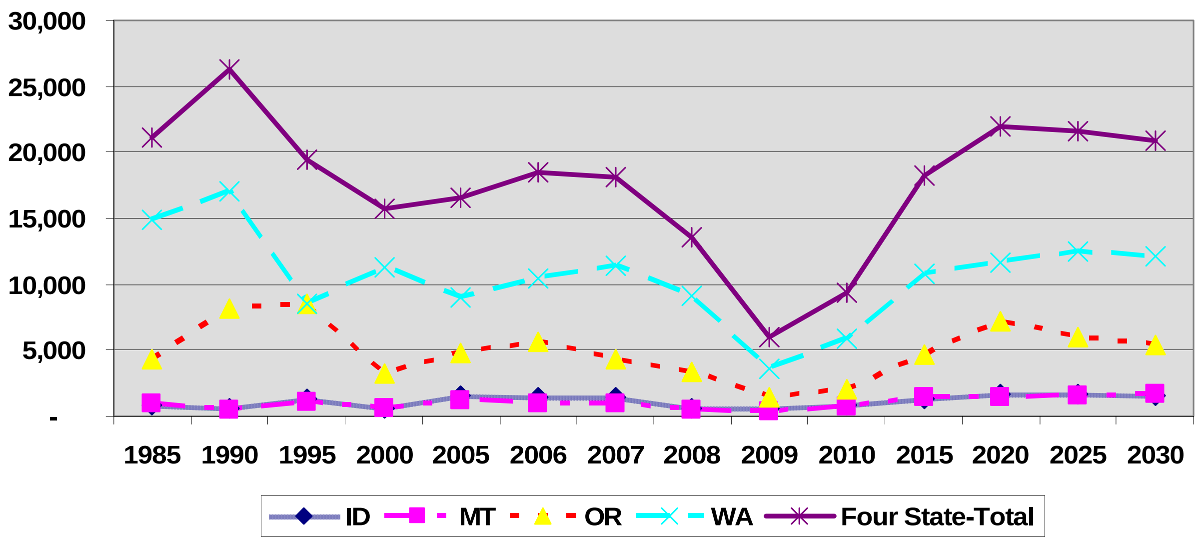



**Figure B-10: New Multi-family Additions**




In summary, the key driver for demand for electricity consumption in the residential sector is the number of residential units. The following table presents the existing residential units for select years.

**Table B-4: Historic and forecast residential units (1000s)**

| Regional Summary | 1985 | 2007 | 2015 | 2020 | 2030 |
|---|---|---|---|---|---|
| Single Family | 2,767 | 4,066 | 4509 | 4848 | 5444 |
| Multi Family | 571 | 984 | 1092 | 1195 | 1410 |
| Other Family | 329 | 585 | 649 | 681 | 752 |

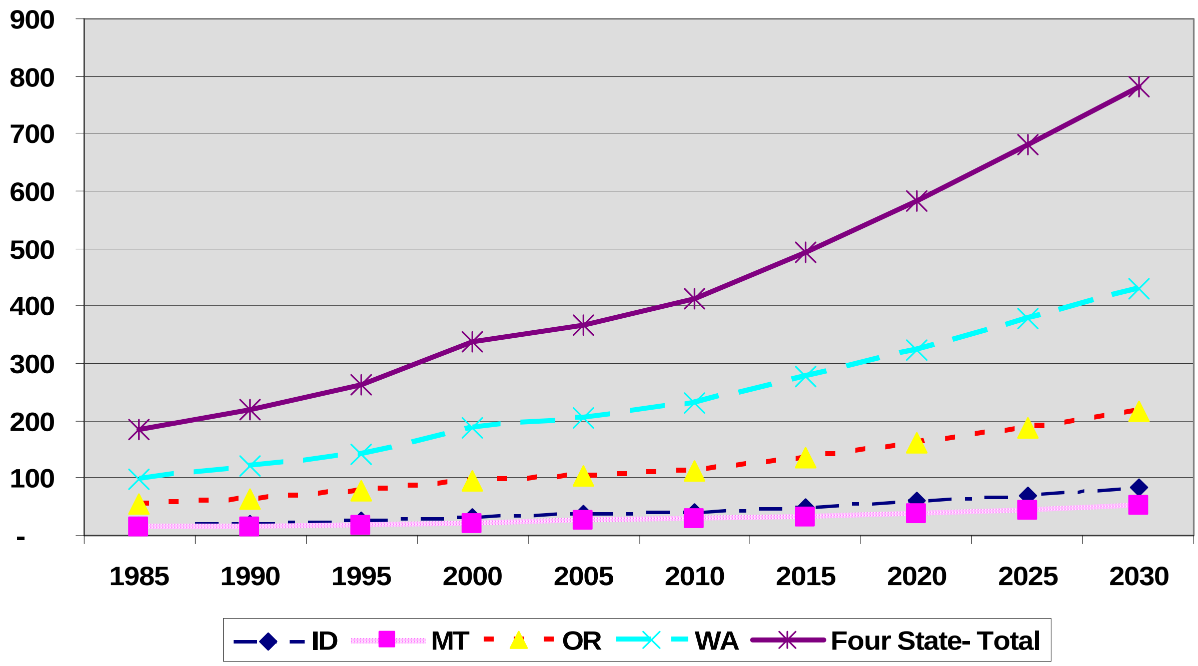
## *Personal Income*

Personal income is another economic driver of energy demand. Energy consumption is elastic, so a decline in personal income causes a short-term reduction in demand. Regional personal income, both in total and on a per-capita basis, has been on the upswing and is projected to continue, although at a slower rate. The following table shows the growth rate, in constant dollars, for personal income in the four states. It should be noted that the impact of the 2008 recession has not been incorporated into these personal income projections.

**Table B-5: Growth Rate Personal Income (2000 constant dollars)**

| | 1985-2007 | 2010-2030 |
|---|---|---|
| **Idaho** | 3.9% | 3.6% |
| **Montana** | 2.7% | 3.1% |
| **Oregon** | 3.3% | 3.4% |
| **Washington** | 3.8% | 3.2% |
| **Four State- Total** | 3.6% | 3.2% |

**Figure B-11: Personal Income**
**(Billions in 2000 constant dollars)**




## *Number of Energy-using Appliances in the Average Residence*

Energy-using appliances also affect energy demand in the residential sector, and the penetration rate of appliances is a key driver of demand. One group of devices that has experienced significant growth in the residential sector has been home electronics (ICE). Very few sources track the penetration rate of this end-use at the regional level, so the following analysis draws on national-level data.

### Information Communication and Entertainment

The explosive growth of these devices has been global, fueled in part by the rapid expansion of the Internet. In a not too distant past, the typical appliances in a typical home consisted of one or two refrigerators; a water heater; perhaps a freezer; some form of space-heating appliance; a cooking appliance; lighting fixtures; and, rarely, an air-conditioning unit. Entertainment appliances were usually limited to a color television and a stereo system.

An average home today has all these appliances, as well as a whole range of ICE devices. Some ICE devices provide services that were once performed outside the home, such as printing pictures or reports. Other ICE devices connect people to the outside world and social networks, and some ICE devices provide entertainment. ICE devices, to a great extent, have removed the boundary between office work and home life. The line between home and work life is increasingly less pronounced as more and more people are able to conduct office work from home.

ICE end-uses are numerous and vary from household to household, depending on the life-style and demographic characteristics of the household. The following table is a partial list of ICE end-uses. The consumption figures are estimates and combine the various duty cycles of the devices.

**Table B-6: Partial Listing of ICE Devices and Estimated Annual Consumption[2]**

| Home Office/Communication Devices | KWh/year | Home Entertainment Devices | KWh/year |
|---|---|---|---|
| Desktop PC | 264 | Home Theater systems | 115 |
| Laptop PC | 74 | TV- CRT | 126 |
| Monitors | 68 | TV-LCD | 108 |
| Inkjet Printer | 21 | TV-Plasma | 281 |
| Laser Printer | 97 | TV-Projection | 237 |
| Scanners | 45 | Digital Cable box | 159 |
| Copiers | 51 | Digital Satellite Receiver | 125 |
| Broadband Devices | 79 | Digital Video Recorder | 264 |
| Home Router | 53 | DVD players | 34 |
| Chargers | 13.1 | | |

U.S. national shipment data for 1997-2006 show that the shipment of laptop computers increased at an annual rate of 16 percent.[3] For the same period, desk top computer shipments increased at a rate of 3 percent annually. Meanwhile, the traditional analog color television was declining at 13 percent per year. In 1997, about 400,000 digital televisions (LCD, plasma, and projection) were shipped, and by 2006 the volume of shipment reached over 21 million units.

At the same time that the number and type of home televisions were increasing, television screen size also increased. For example, in 1999, over 83 percent of residential televisions were less than 32 inches, and about 5 percent were larger than 46 inches. In 2008, over 30 percent of

[2] Pacific Gas and Electric Company, Emerging Technologies Program Application Assessment Report #0513 Consumer Electronics: Market Trends, Energy Consumption, and Program Recommendations 2005-2010, Issued: December 2006

[3] Appliance Magazine data for U.S. manufacturers

televisions are now over 46 inches and only 14 percent are less than 32 inches.[4] As screen size increases, so does energy consumption. A 32-inch or less television consumes about 172 kilowatt hours per year compared to the 283 (or more) kilowatt hours that televisions with 46-inch or wider screens consume.

**Figure B-12: Growth in Computer Sales**

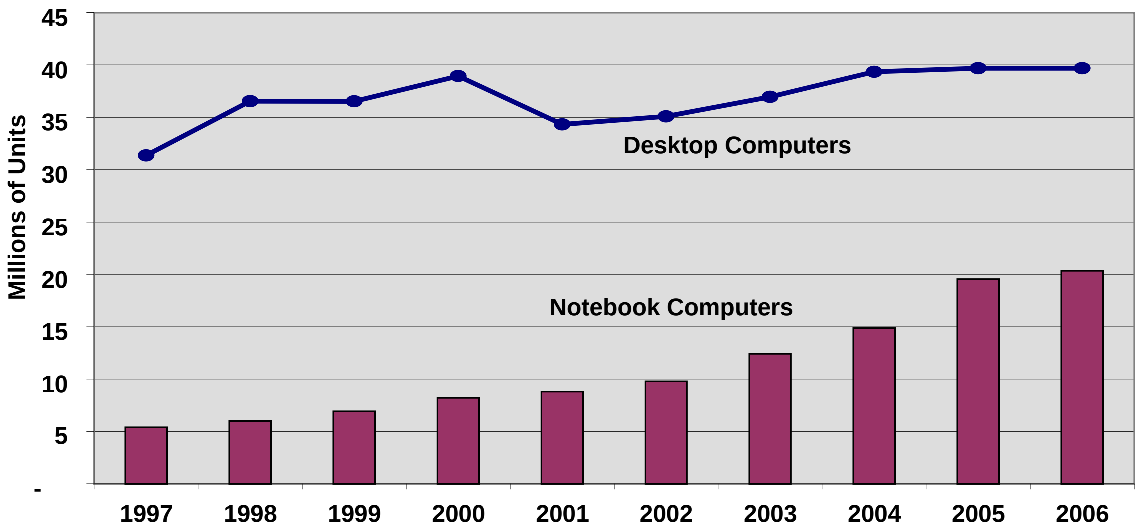
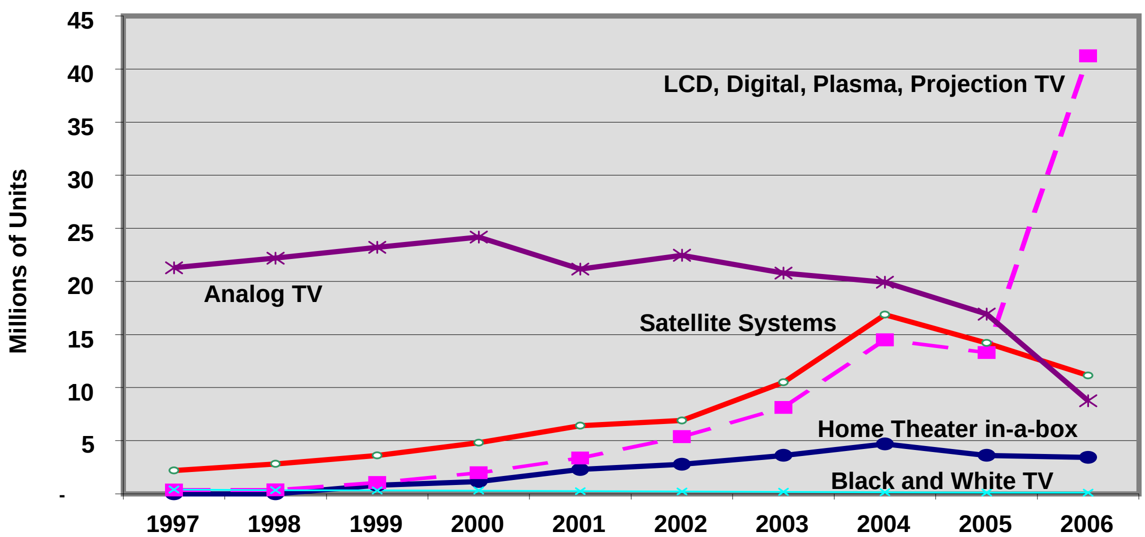



**Table B-7: Annual Growth Rate in Shipment of Entertainment Equipment**

| | 1997-2006 |
|---|---|
| **Home Theater-In-a-Box** | 23% |
| **LCD, Digital, Plasma, Projection TV** | 69% |
| **Satellite Systems** | 17% |
| **Televisions, Black & White (Monochrome)** | -14% |
| **Televisions, Color, Analog** | -13% |

[4] 2008 study conducted for Northwest Power and Conservation Council by ECOS consulting.

**Figure B-13: Annual Shipment of TVs and Satellite Systems**




## Demand for Air Conditioning

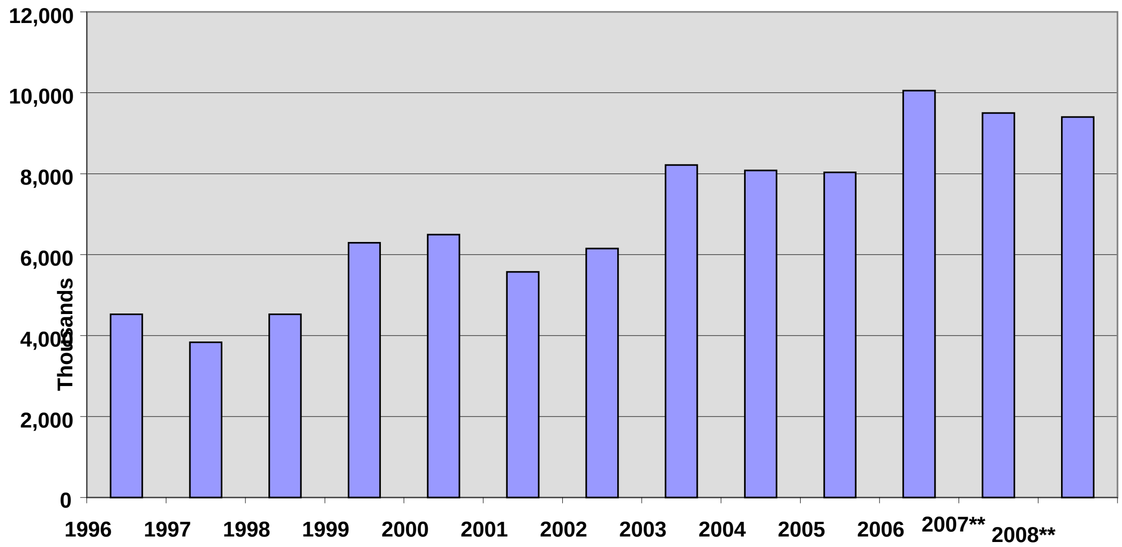
Residential air conditioning has grown rapidly in the region. The market penetration of air conditioning by Northwest homeowners was relatively low, about 10-20 percent, during the 1980s and 1990s. Air conditioning use has been increasing significantly in recent years. This shift in demand can be attributed to warmer summer temperatures, reduced prices of air-conditioning units, and the number of new people moving into the region who are accustomed to using air-conditioning in their previous homes. The following table shows that in 2000, about 40,000 room air conditioning units were shipped to the region. Five years later, the figure had increased to about 140,000. State-specific figures are not available at this writing, but if the national trends are any indication, the volume of room air conditioning units in 2006 would show a significant increase.

**Table B-8: Shipment of Room Air Conditions to the Region (number)**

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Annual Growth Rate |
|---|---|---|---|---|---|---|---|
| **Idaho** | 5,300 | 5,400 | 7,500 | 13,000 | 13,600 | 9,998 | 14% |
| **Montana** | 4,200 | 4,900 | 8,000 | 12,400 | 15,300 | 7,926 | 14% |
| **Oregon** | 15,800 | 17,300 | 21,100 | 39,800 | 58,700 | 55,469 | 29% |
| **Washington** | 16,200 | 27,300 | 32,600 | 45,300 | 90,700 | 66,163 | 33% |

The increase in room air-conditioning has not been a regional phenomenon. Similar trends can be seen in national figures. Between 1997 and 2006, room air-conditioning sales grew at an annual rate of 11 percent, almost 10 times the population growth rate. Sales increased from about 4 million units in 1997 to about 10 million units in 2006. The sales volume for room air-conditioning depends on summer temperatures, which is evident from the high sales volume in 2006--one of the hottest years on record.

**Figure B-14: Recent Trends in Nationwide Shipment of Room Air Conditioners [5]**




# ECONOMIC DRIVERS OF THE COMMERCIAL SECTOR

The key economic driver for the commercial sector's energy demand is the square footage needed for commercial enterprises. In modeling this sector, the space requirement of thousands of business activities was calculated and aggregated into 17 different building types.

## *Methodology in Estimating Commercial Floor Space Requirements*

The key driver for the commercial sector is the stock square footage required to conduct business activities in designated building types. To calculate this square footage, a simple model was developed that uses the number of employees per business activity and median square footage per building type. The following analytic steps were taken:

1. The number of establishments[6] and employees in 2005 (at 6-digit NAICS[7] code level) was obtained from the Bureau of Labor Statistics. This enabled a detailed investigation of the type of business activities and the number of employees for each business type. Each business activity was assigned one of the 17 commercial building types used in load forecasting and conservation assessment.
2. The median square footage per main-shift employees (the hours of 8 a.m.-5 p.m.) for various business activities reported as part of Commercial Building Energy Consumption Surveys (CBEC) was obtained from the Department of Energy.
3. CBEC micro data (individual site data) for 1992-2003 for more than 21,000 buildings was used to calculate the median square footage per employee and the number of hours of operation for various establishments.

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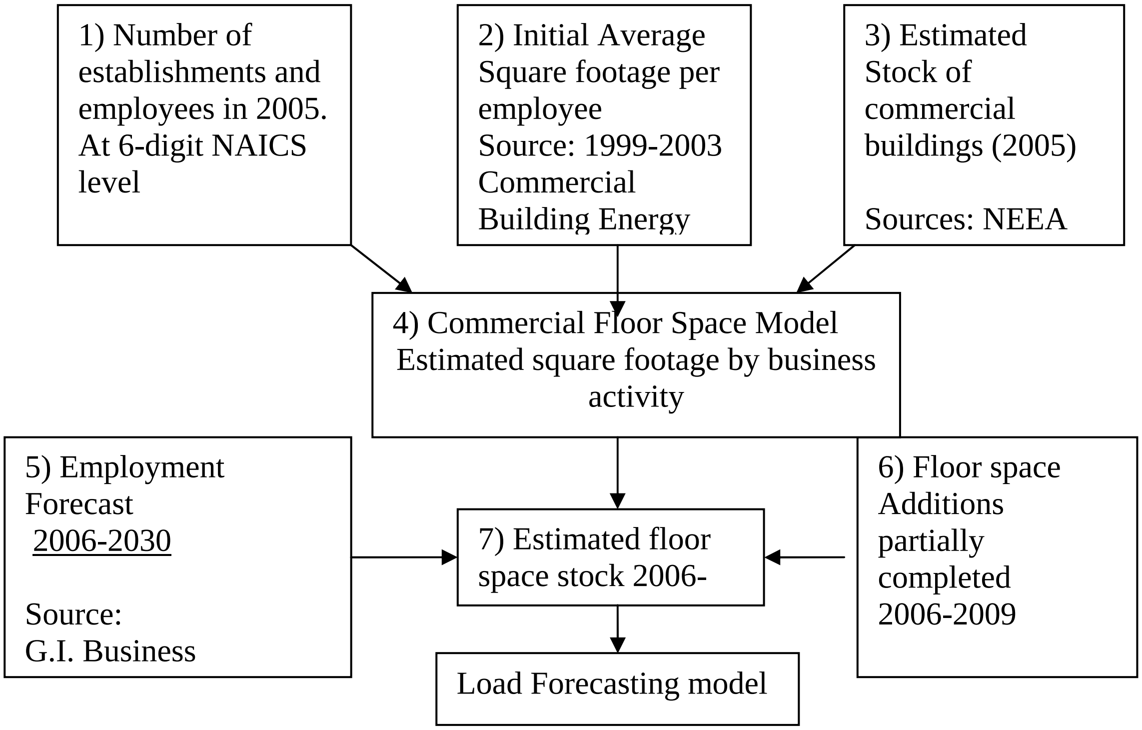
5 -Association of Home Appliance Manufacturers data. 2007 and 2008 are forecasts.
6 Establishment - A single physical location where business is conducted or where services or industrial operations are performed.
7 NAICS - North American Industrial Classification System

4. The percent of "major" occupation categories engaged in a business activity (at 4-digit NAICS) was obtained from the Bureau of Labor Statistics. http:/stat.bls.gov/oes/home.htm
5. An estimate of existing floor space stock and the demolition rate by building type was obtained from the Commercial Building Stock Analysis (NEEA 2004).
6. Floor space additions for each building type for 2002-2005 was obtained from F.W. Dodge and used to augment the 2001 building floor space stock to create an assessment of the existing floor space in 2005. This floor space stock was reduced by calculated demolitions during 2002-2005.
7. An initial estimate of 2005 square footage requirements for each business activity was estimated using the following factors:
   a. The assigned building type
   b. Median square footage per employee
   c. Number of employees
   d. Percent of business activity engaged in an occupation
8. The estimated 2005 floor space stock for each business activity was adjusted so that the total square footage for that building type is close to the benchmark floor space stock in 2005.
9. Future floor space requirements were forecast by applying the annual growth rate in employment in each business activity to Global Insight's forecast (at state, and 4-digit NAICS code level), and to the 2005 floor space requirements for that business activity.
10. For each year, the new floor space requirements across business activities were aggregated by building type, and for each building type, a portion of floor stock is estimated to be demolished.
11. To capture the construction projects that are partially complete for 2006-2009, the Council replaced its model's estimate for the square footage additions with those reported by F.W. Dodge for construction projects in the pipeline.
12. For years 2006-2030, the estimated commercial floor space stock is fed into the demand forecasting model.

**Figure B-15: Analytic Steps in Forecasting Floor Space for Each State**




The Northwest Energy Efficiency Alliance's (NEEA) market research report[8] estimated that in 2001 the total commercial floor space in the Pacific Northwest was 2.4 billion square feet. Taking these estimates, and the new floor space additions for 2001-2005 from F.W. Dodge, staff estimated the commercial building stock in the region to be about 2.7 billion square feet in 2005. Roughly 300 million square feet were added between 2001 and 2005 and an estimated 60 million square feet were demolished.

**Table B-9: 2005 Commercial Building Stock (1,000,000 SQF)**

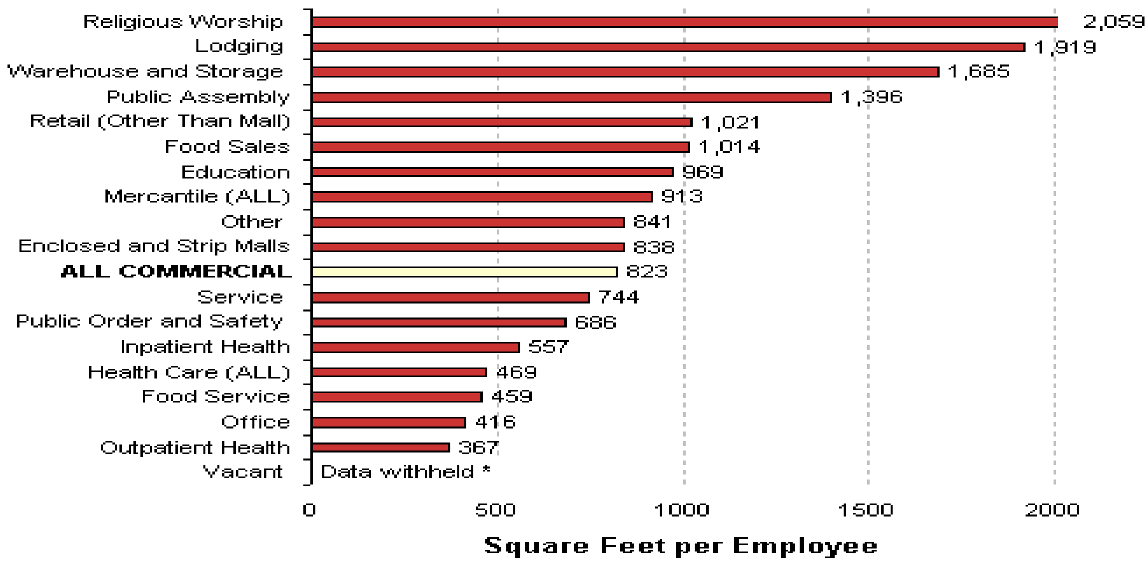
| | Idaho | Montana | Oregon | Washington | Total |
|---|---|---|---|---|---|
| **Office (3 types)** | 27 | 34 | 104 | 340 | 504 |
| **Retail (4 types)** | 29 | 25 | 156 | 289 | 500 |
| **K-12** | 26 | 21 | 38 | 152 | 237 |
| **University** | 13 | 8 | 20 | 77 | 118 |
| **Hotel** | 16 | 25 | 52 | 69 | 162 |
| **Hospital** | 7 | 5 | 20 | 37 | 68 |
| **Hospital Other (Elder Care)** | 17 | 10 | 32 | 75 | 133 |
| **Restaurant** | 3 | 4 | 15 | 25 | 48 |
| **Grocery** | 8 | 6 | 9 | 32 | 55 |
| **Grocery Other** | 3 | 2 | 4 | 13 | 22 |
| **Warehouse** | 26 | 19 | 131 | 156 | 331 |
| **Assembly** | 17 | 11 | 43 | 130 | 202 |
| **Other** | 36 | 21 | 82 | 251 | 391 |
| **Total** | 230 | 192 | 705 | 1,645 | 2,772 |

[8] "Assessment of the Commercial Building Stock in the Pacific Northwest" March 2004

## Square Footage per Employee

Using the Department of Energy's Commercial Building Energy Consumption survey data (micro-data from a national survey of over 21,000 commercial buildings surveyed between 1992 and 2003), we estimate the median square footage per employee for various business activities. A graphic example of the initial square footage per employee used in the model (from CBECS 1999) is shown here.

**Figure B-16: Median Square Footage per Employee**




Note: "Mercantile (ALL)" includes both "Retail (Other Than Mall)" and "Enclosed and Strip Malls"; "Health Care (ALL)" includes both "Inpatient Health" and "Outpatient Health".
* Relative Standard Error (RSE) greater than 50 percent or fewer than 20 buildings sampled.
Source: Energy Information Administration, 1999 Commercial Buildings Energy Consumption Survey.

## Calibration to Benchmark Year Stock

The floor space estimates were then compared with the actual floor space figures by state and building type for 2005. The 2001 commercial building stock assessment had categorized a large portion of the building stock, nearly 20 percent, to the "other" category. To better understand the nature of this category of buildings, a detailed model was developed to estimate floor space requirements for various business activities. Through this analysis, the amount of floor space that was designated as "other" was reduced and assigned to the appropriate floor space types for "office," "warehouse," or "assembly." This enables us to have a better estimate of the conservation potential of these commercial enterprises and the demand forecast for the region.

Table B-10 shows the estimated share of building stock before and after the detailed analysis of business activities. Other building types now represent about 5 percent of building stock. An increase in the share of office, warehouse, and assembly buildings can be observed.

**Table B-10: Percent of Commercial Floor Space by Building Type**

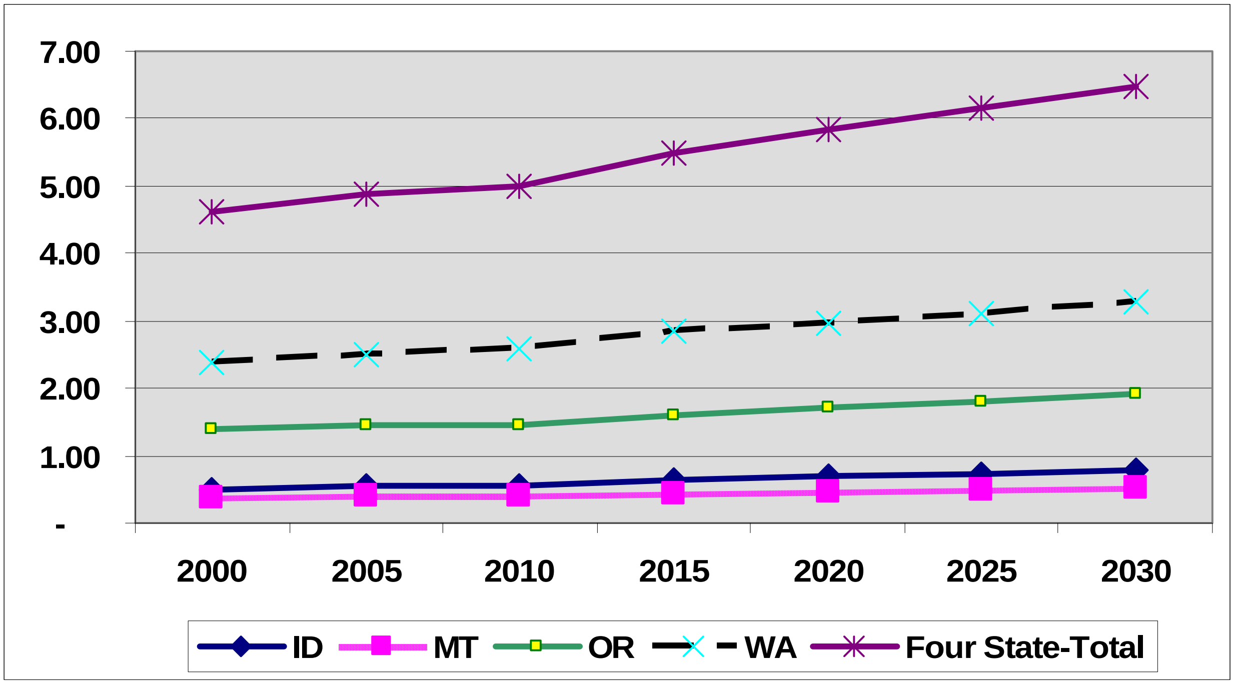
| | Initial Market Segmentation | Final Market Segmentation |
|---|---|---|
| **Office** | 18.2% | 24.1% |
| **Retail** | 18.0% | 18.1% |
| **Hospital** | 2.5% | 2.5% |
| **Hospital Other** | 4.8% | 4.8% |
| **Hotel** | 5.9% | 6.3% |
| **Restaurant** | 1.7% | 1.8% |
| **Grocery** | 2.0% | 2.0% |
| **Grocery Other** | 0.8% | 0.8% |
| **K-12** | 8.6% | 8.9% |
| **University** | 4.3% | 4.4% |
| **Warehouse** | 11.9% | 12.0% |
| **Assembly** | 7.3% | 9.2% |
| **Other** | 14.1% | 5.1% |

Other sources of information used for verifying the results of the analysis were the grocery and supermarket data that NEEA had purchased. This data confirmed that grocery store square footage developed by our model was within 2 percent of actual floor space data.

## *Forecasting Commercial Floor Space Requirements*

A model forecasting the square footage requirements of the commercial sector was developed and calibrated to the known square footage data for 2005. Then, using Global Insight's business demographic forecast of employment, the Council was able to forecast the square footage requirement for commercial buildings. The following figures show the historic and forecast commercial employment totals in the region, and then broken down by major business activity. Between 2010 and 2030, the overall commercial employment is expected to grow at an annual rate of 1.1 percent, with total commercial employment growing from 5.1 million in 2007 to about 6.5 million by 2030.

**Figure B-17:  Commercial Employment Projection (Millions)**




## *Changing Composition of Commercial Sector*

The employment market share of business activities in the commercial sector has not been constant.  Over the past 10 years, some business sectors have increased their market share, while other sectors experienced a declining market share.  For example, businesses engaged in health care, information technologies, professional and technical services, and wholesale trade services have increased their market share, while government and retail trade have reduced their market share.  The historic and forecast trends are presented in the following table.

**Table B-11: Percent Market Share of Employment**

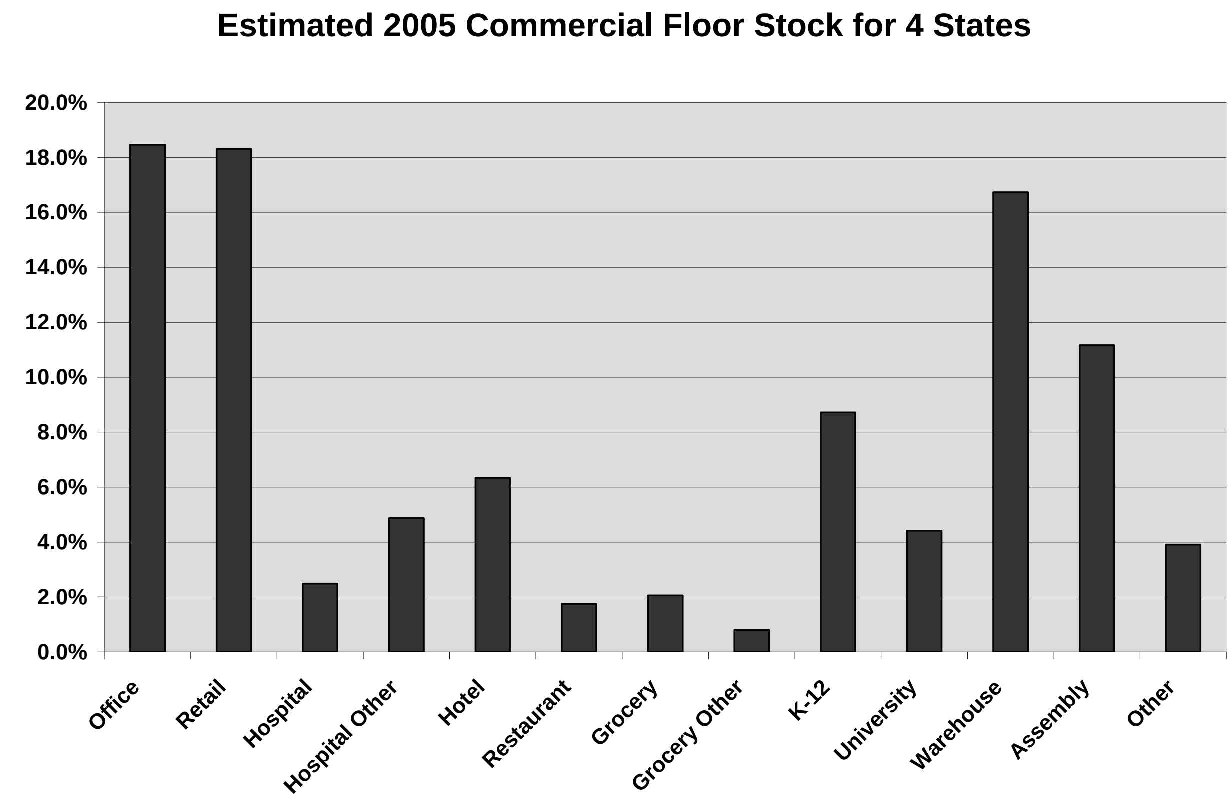
| **Businesses with Increasing Employment Market Share** | **1997** | **2007** | **2030** |
|---|---|---|---|
| Health Care and Social Assistance | 10.8% | 11.7% | 12.5% |
| Administrative and Support and Waste Management | 5.4% | 6.1% | 9.8% |
| Information | 2.9% | 3.1% | 3.7% |
| Transportation and Warehousing | 3.9% | 3.5% | 3.6% |
| Professional, Scientific, and Technical Services | 5.1% | 5.5% | 7.3% |
| Wholesale Trade | 5.5% | 4.9% | 5.1% |
| **Businesses with Declining or stable Market Share** | **1997** | **2007** | **2030** |
| Construction | 6.4% | 7.7% | 7.4% |
| Government Employees | 21.3% | 20.0% | 18.6% |
| Retail Trade | 13.8% | 13.0% | 10.7% |
| Accommodation and Food Services | 9.6% | 9.4% | 8.0% |
| Other Services (except Public Administration) | 4.4% | 3.9% | 3.4% |
| Finance and Insurance | 4.0% | 4.0% | 3.3% |
| Real Estate and Rental and Leasing | 2.2% | 2.1% | 2.0% |
| Arts, Entertainment, and Recreation | 1.6% | 1.8% | 1.7% |
| Educational Services | 1.5% | 1.7% | 1.5% |
| Management of Companies and Enterprises | 1.4% | 1.4% | 1.3% |
| Utilities | 0.4% | 0.3% | 0.2% |
| **Total Employment in Commercial Activities (000)** | **4,222** | **5,164** | **6,478** |

To establish the relationship between floor space requirements and the number of employees, data from the Commercial Building Stock Analysis (NEEA 2004) was used to estimate the existing floor space stock and the demolition rate by building type in 2004. It was then used to estimate the commercial floor space stock in 2005. The following figures show the estimated commercial floor space stock in 2005. These estimates, along with the data on the number of employees, were used to forecast floor space requirements.

**Table B-12: Commercial Floor Space Stock 2005 (millions SQF)**

| **Building type** | **Idaho** | **Montana** | **Oregon** | **Washington** | **Total** |
|---|---|---|---|---|---|
| **Office** | 29 | 36 | 100 | 340 | 505 |
| **Retail** | 29 | 26 | 155 | 290 | 500 |
| **hospital** | 7 | 5 | 20 | 37 | 68 |
| **Hospital Other** | 17 | 9 | 32 | 75 | 133 |
| **Hotel** | 18 | 27 | 57 | 72 | 173 |
| **Restaurant** | 4 | 5 | 15 | 24 | 48 |
| **Grocery** | 8 | 6 | 10 | 32 | 56 |
| **Mini Marts** | 3 | 2 | 4 | 13 | 22 |
| **K-12** | 27 | 21 | 38 | 152 | 238 |
| **University** | 13 | 9 | 20 | 78 | 121 |
| **Warehouse** | 35 | 21 | 131 | 272 | 457 |
| **Assembly** | 25 | 31 | 95 | 155 | 305 |
| **Other** | 11 | 9 | 31 | 56 | 107 |
| **Total** | 225 | 207 | 708 | 1,596 | 2,735 |

**Figure B-18: Regional Commercial Floor Stock Market Share (2005)**




The floor space stock in each year is the sum of new floor space additions and retirements from the floor space in that year. The forecast for floor space additions for each state and the region is shown in the following figure. The Council's Sixth Power Plan forecasts about 900 million square feet of new floor space. A large portion of this will be in warehouse space, office space, K-12 schools, and elder care facilities.

**Table B-13: 2010-2030 New Commercial Floor Space Additions (millions of SQF)**

| | Idaho | Montana | Oregon | Washington | Region |
|---|---|---|---|---|---|
| **Large Off** | 5.96 | 5.26 | 15.56 | 71.32 | 98.09 |
| **Medium Off** | 2.68 | 2.37 | 7.01 | 32.13 | 44.19 |
| **Small Off** | 3.15 | 2.78 | 8.23 | 37.70 | 51.86 |
| **Big Box-Retail** | 1.71 | 1.25 | 7.73 | 11.95 | 22.64 |
| **Small Box-Retail** | 3.16 | 2.31 | 14.28 | 22.07 | 41.81 |
| **High End-Retail** | 0.79 | 0.58 | 3.57 | 5.52 | 10.45 |
| **Anchor-Retail** | 1.52 | 1.11 | 6.89 | 10.65 | 20.18 |
| **K-12** | 5.13 | 4.17 | 6.81 | 39.28 | 55.39 |
| **University** | 3.05 | 1.55 | 4.63 | 22.71 | 31.95 |
| **Warehouse** | 19.55 | 7.23 | 54.48 | 185.91 | 267.17 |
| **Supermarket** | 0.82 | 0.46 | 0.86 | 3.30 | 5.45 |
| **Mini Mart** | 0.97 | 0.32 | 0.57 | 2.93 | 4.79 |
| **Restaurant** | 1.62 | 1.13 | 3.85 | 7.35 | 13.94 |
| **Lodging** | 3.12 | 1.67 | 5.28 | 11.59 | 21.66 |
| **Hospital** | 1.91 | 0.75 | 5.06 | 8.93 | 16.65 |
| **Other Health*** | 7.87 | 3.88 | 10.09 | 41.58 | 63.41 |
| **Assembly** | 17.44 | 7.46 | 27.45 | 26.24 | 78.58 |
| **Other** | 6.83 | 5.48 | 15.31 | 20.12 | 47.74 |
| **Total** | 87.28 | 49.75 | 197.64 | 561.29 | 895.96 |

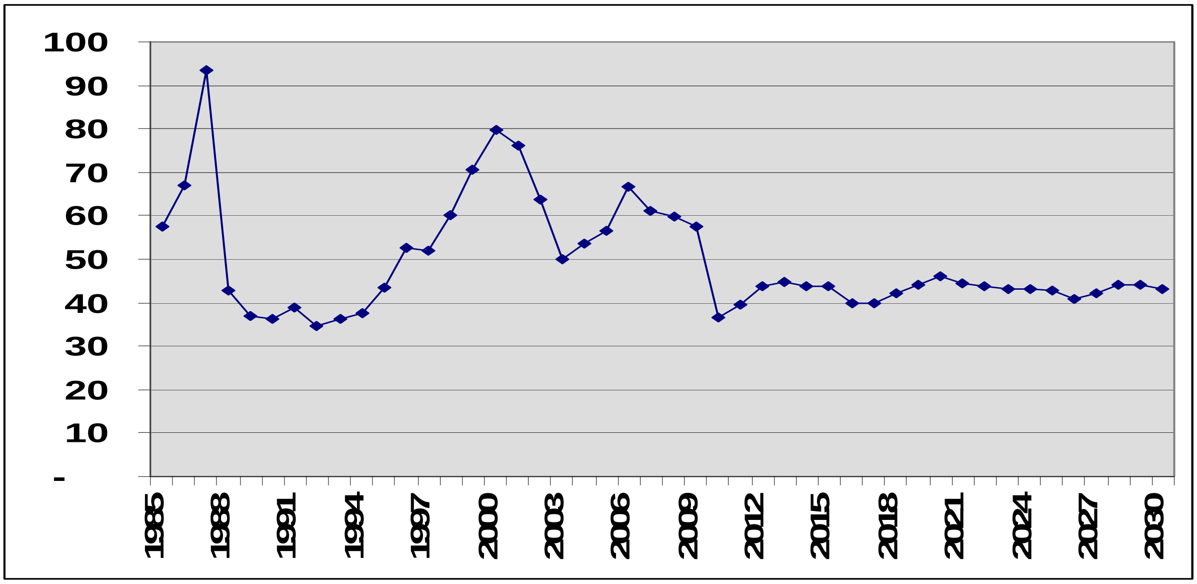
*- elder care facilities

## *Commercial Floor Space Additions*

The overall pattern of floor space additions for the commercial sector is presented in the following graph. A quick review of the historic data shows the cyclical nature of commercial floor space additions. The sharp increase in late 1980s is followed by a significant slow down in the early 1990s. The late 1990s indicate a sharp increase in new construction activities. The 2000-2002 recession slowed construction activities. In 2005, another wave of commercial construction took place. Due to the long construction time for commercial activities, it would typically take a year or two for construction activities to reflect the economy. The slow down in construction activities due to the current recession would be reflected in the level of new commercial construction activities after a few years. The current forecast indicates that it would be at least 2011-2012 before commercial construction activities increase.

The long-term forecast projects a slow down in floor space additions, from 60 million square feet per year to about 40 million square feet. The forecast for future floor space additions does not show a wide swing in construction activities in the sector. However, there are different patterns of floor space additions, depending on the building category.

**Figure B-19: Total Commercial Floor Space Additions (Northwest Region)**
**Millions of SQF**

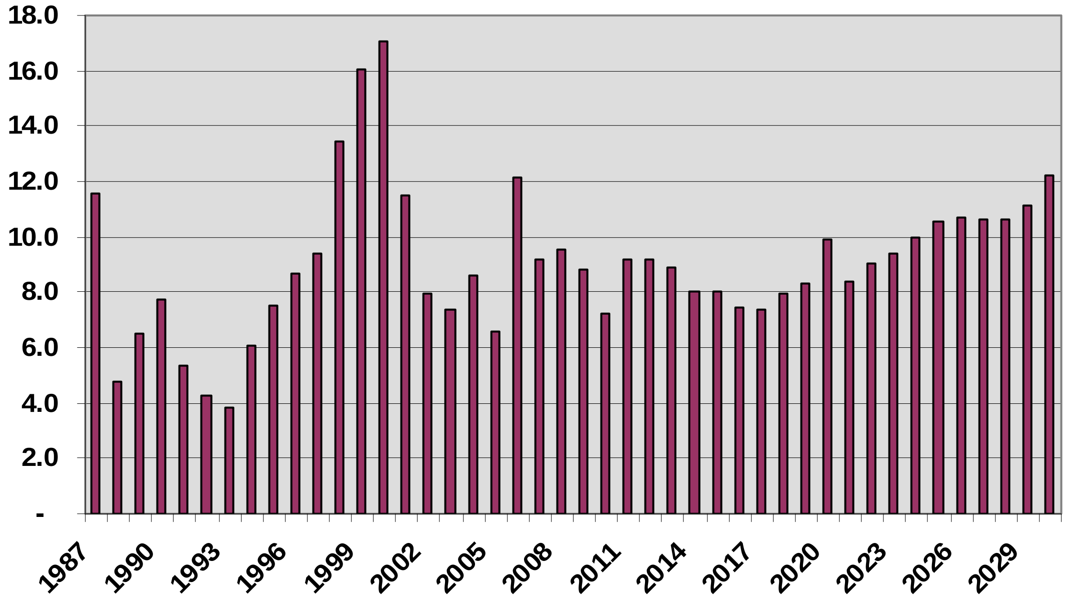



## Patterns of Commercial Floor Space Additions

Commercial floor space additions typically show a cyclical pattern of overbuilding followed by high occupancy and demand for more space. This is especially true for the more speculative building types such as office or retail. A brief review of commercial floor space additions for 1987-2030 shows the different patterns of floor space additions for office, retail, warehouse, K-12 schools, and elder care facilities. An increase in office space additions, declining retail space requirements, substantial increases in new warehouse space, and declining K-12 school floor space requirements are forecast.

Office space requirements suggest a decline in new office space additions for 2012-2014, followed by a stable period from 2015-2019. Starting with 2020, the Council forecasts an escalation of commercial office construction activities.

**Figure B-20: Pattern of Office Space Addition**




A decrease in retail floor space requirements and new retail space additions are expected over the forecast period. This decrease reflects slower population growth and the move to e-commerce. Retail space additions peaked in 2005-2006. In the 2010-2030 period, retail commercial floor space construction is forecast to average around 4 million square feet per year.

A decrease in retail space requirement is off-set by an increase in demand for warehouse space. The increase in warehouse space reflects the expanding market for e-commerce.

**Figure B-21: Pattern of Retail Space Addition**

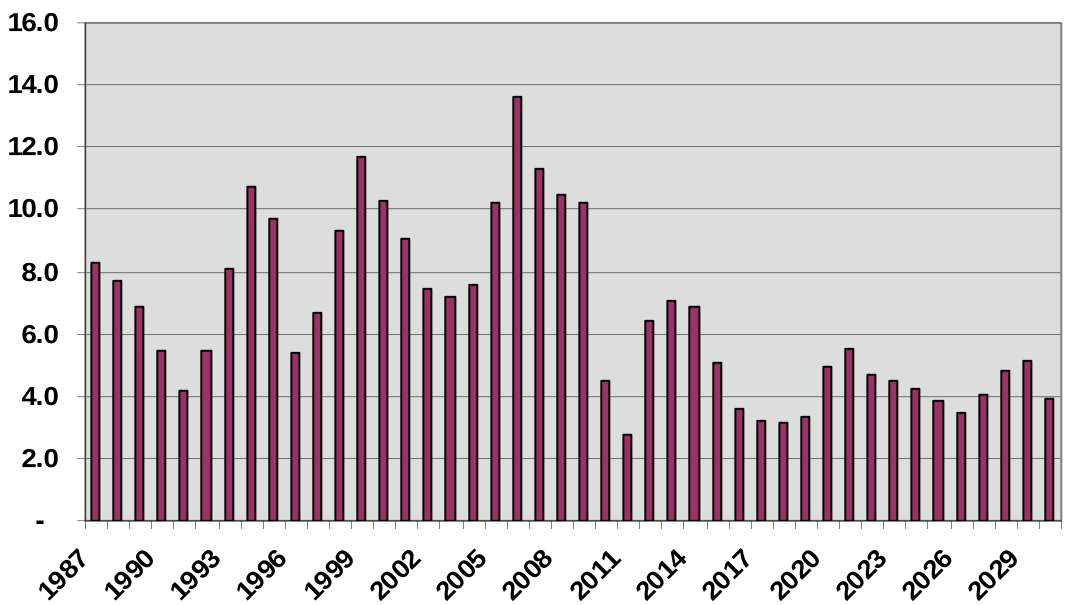
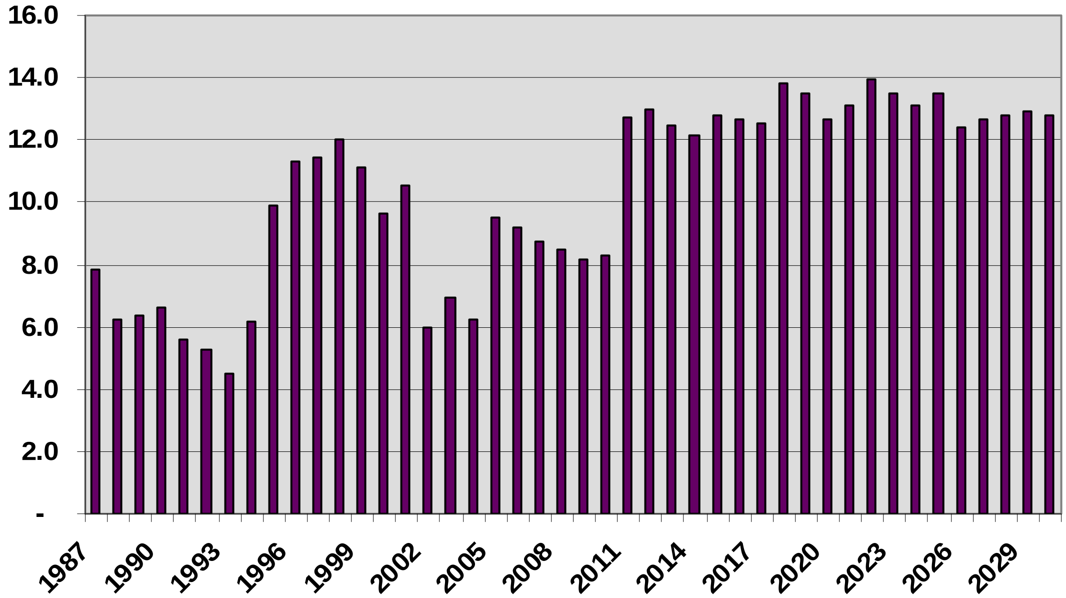
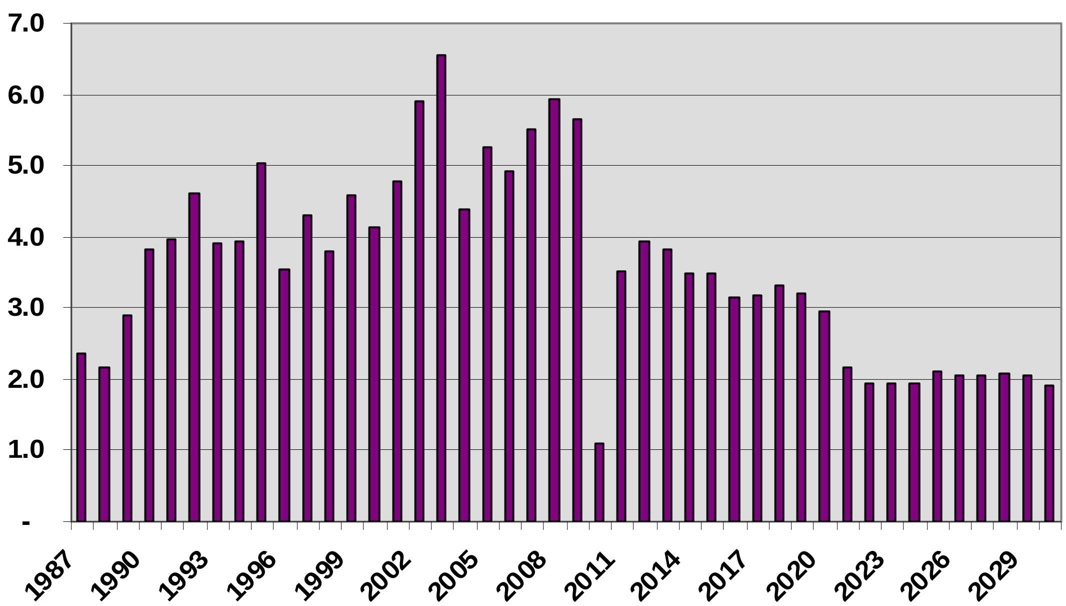


**Figure B-22: Pattern of Warehouse Floor Space Addition**



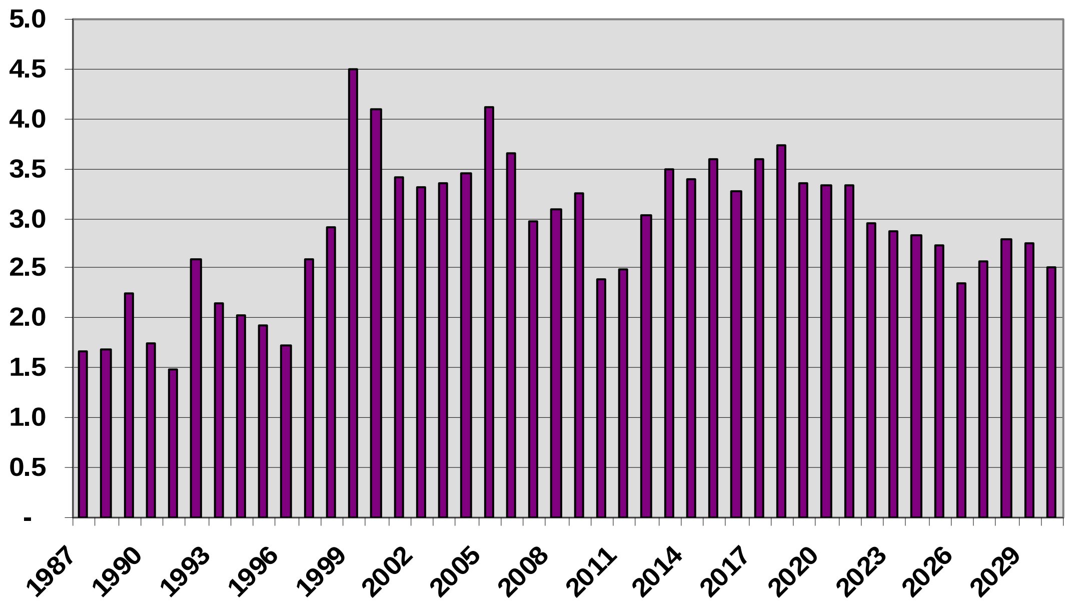

The demand for the schools and elder care are driven by the demographic changes facing the region. Population in the region is growing at a slower rate and a larger population is at retirement age. The pattern of floor space additions for K-12 schools reflects the declining share of the under 19 population. Between 1985 and 2007, the regional population of this age group increased by 666,000. But between 2010 and 2030, this population group is forecast to grow by about 540,000 people. The floor space requirement forecast for K-12 schools is expected to decline in two steps. From 2011-2018 the forecast for floor space additions is for about 3-4 million square feet per year. From 2020-2030, the forecast goes down to less than 2 million square feet per year.

**Figure B-23: Pattern of Floor Space Addition for K-12 Schools**



The elderly population, 65 and older, is increasing from about one million in 1985 to about 1.5 million in 2007, and to over 3 million by 2030.  This more than doubling of population is forecast to increase the demand for special elder care facilities.  In the 2011-2018 period, new floor space for these facilities is forecast to increase by about 3.5-4.0 million square feet per year.  After 2020, the forecast for new floor space drops to 2.5 to 3.0 million square feet per year.

**Figure B-24:  Pattern of Floor Space Addition for Elder Care Facilities**




## *Commercial Floor Space Stock*

Commercial floor space stock is projected to increase from 2.9 billion square feet to about 3.9 billion square feet over the 2007-2030 period.  Sectors showing the greatest increase in floor space additions are large office, warehouse, and other health (elder care) facilities.  Warehouse floor space shown here does not include self-storage facilities or warehouses associated with manufacturing facilities.

**Table B-14: Regional Commercial Floor Space Stock (millions sqf)**

| Regional Summary | 1985 | 2007 | 2015 | 2020 | 2030 | 2007-2030 Addition | Market share 2007-2030 |
|---|---|---|---|---|---|---|---|
| Large Office | 190 | 266 | 301 | 321 | 373 | 107 | 11% |
| Medium Office | 49 | 120 | 135 | 145 | 168 | 48 | 5% |
| Small Office | 90 | 141 | 159 | 170 | 197 | 57 | 6% |
| Big Box-Retail | 20 | 125 | 138 | 142 | 152 | 28 | 3% |
| Small Box-Retail | 171 | 231 | 254 | 262 | 282 | 51 | 5% |
| High End-Retail | 44 | 58 | 64 | 66 | 70 | 13 | 1% |
| Anchor-Retail | 98 | 111 | 123 | 127 | 136 | 25 | 2% |
| K-12 | 155 | 248 | 279 | 294 | 315 | 67 | 7% |
| University | 77 | 123 | 138 | 147 | 160 | 37 | 4% |
| Warehouse | 170 | 349 | 437 | 502 | 633 | 284 | 28% |
| Supermarket | 43 | 55 | 57 | 58 | 60 | 6 | 1% |
| Mini Marts | 5 | 22 | 24 | 25 | 28 | 5 | 1% |
| Restaurant | 36 | 48 | 54 | 57 | 63 | 15 | 1% |
| Lodging | 116 | 169 | 183 | 187 | 195 | 27 | 3% |
| Hospital | 39 | 67 | 76 | 81 | 87 | 20 | 2% |
| Other Health ( Elder Care) | 85 | 144 | 169 | 186 | 214 | 70 | 7% |
| Assembly | 123 | 211 | 235 | 255 | 298 | 87 | 9% |
| Other | 240 | 420 | 450 | 462 | 488 | 68 | 7% |
| Total | 1,751 | 2,908 | 3275 | 3487 | 3919 | 1013 | 100% |

# ECONOMIC DRIVERS FOR INDUSTRIAL SECTOR DEMAND

Demand for energy in the industrial sector is driven by the demand for goods and products produced in the region. Historically, demand for electricity in the industrial sector was dominated by a few large energy-intensive industries. However, the regional mix of industries has been changing toward less electricity and energy-intensive industries, and the region’s industries now resemble the rest of the country. The following figure tracks total energy use per dollar of GDP (constant dollars) for the nation and the Northwest. Since 1960, there has been a trend toward less energy use in this sector. During the 1980s and 1990s, industries in the Northwest used significantly more energy for every dollar of output they produced. Since 2002, however, the intensity of energy use for both the region and nation has been identical. Figure B-26 shows the declining trend in electricity intensity of the industrial sector in the Northwest. The industrial demand excludes Direct Service Industries.

**Figure B-25: Change in National and Regional Energy Intensity**

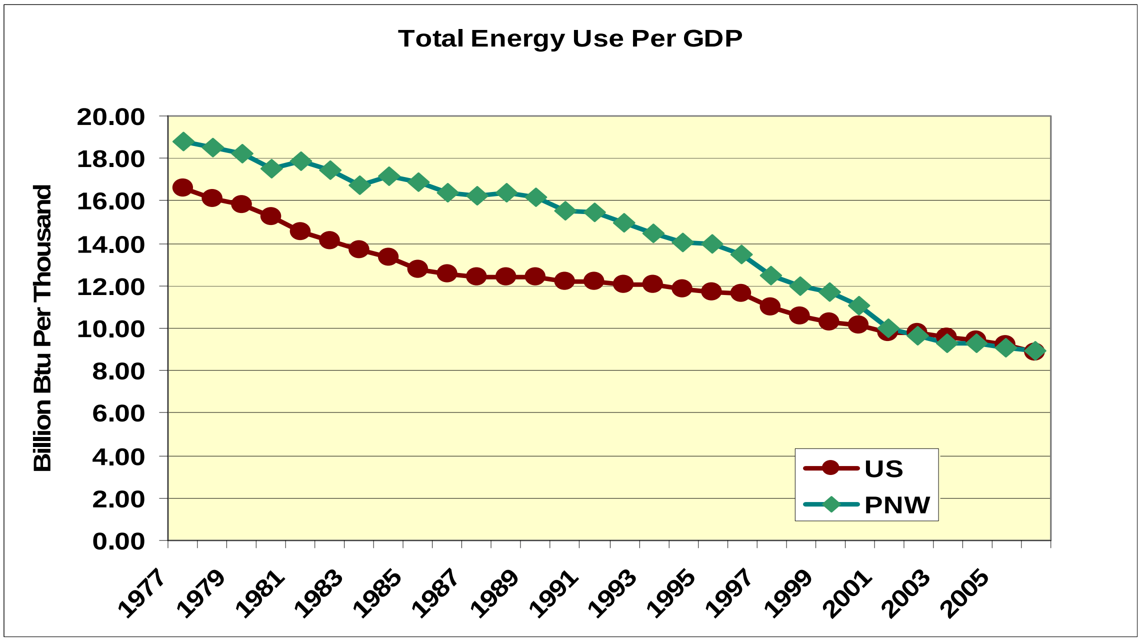
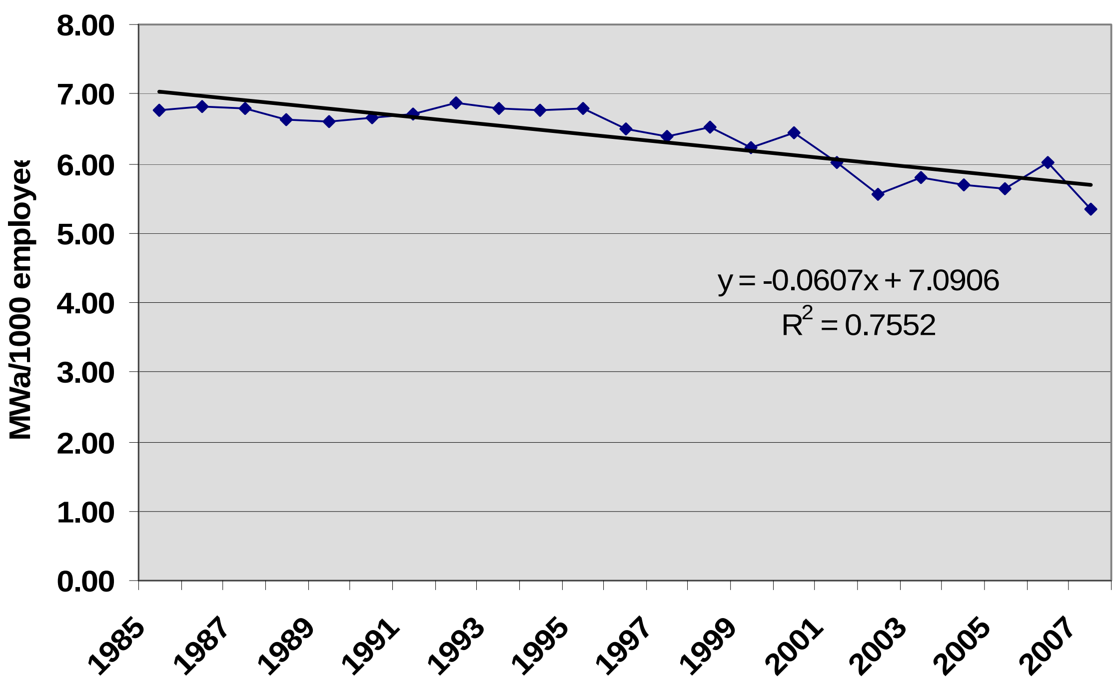



**Figure B-26: Energy Intensity of non-DSI Industrial Sector in the Northwest MWa/1000 Industrial Employee**



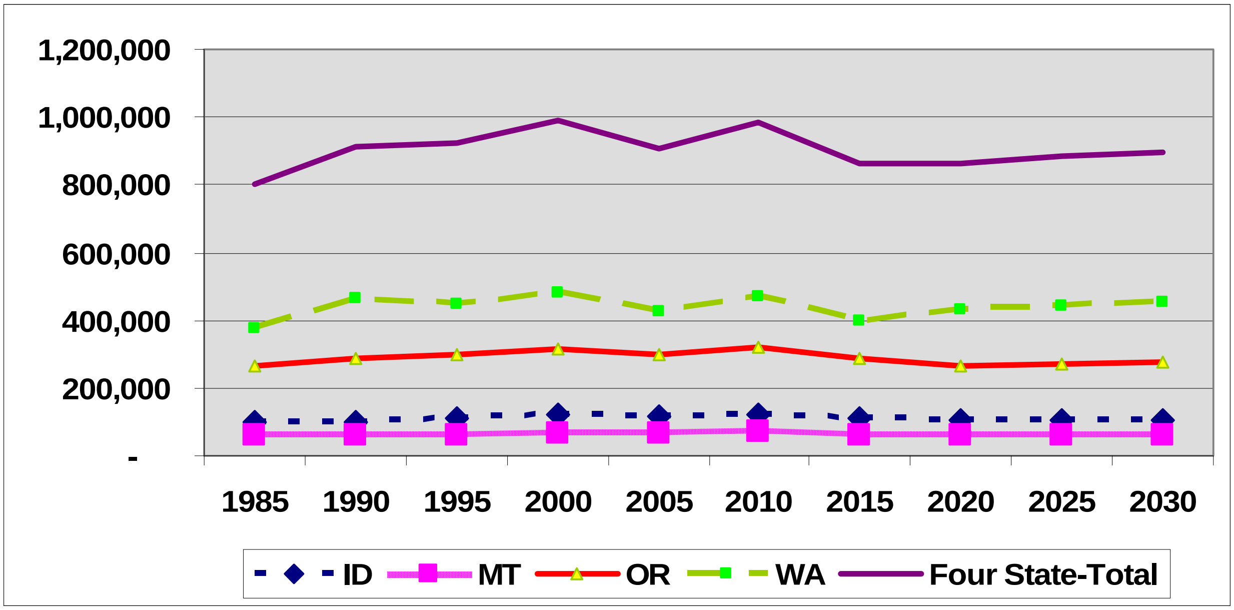
## Projected Employment Growth

The demand forecast model tracks 21 distinct industries. The demand for energy consumed in each industry is forecast using the estimated growth in the product output in that industry. Output in each industry is forecast based on the projected employment in the industry and the average productivity of employees. Productivity is measured in terms of dollars of output per number of employees. Industrial employment has been on the decline, but that decline is projected to slow. The following figure shows the number of industrial employees for 2000, 2002, 2007, and 2030. Industrial employment peaked at about 730,000 in 2000, but it declined significantly during the 2000-2002 period to about 650,000. Industrial employment has been growing slowly; by 2007 it reached 700,000, and it is forecasted to be relatively flat in the future. The composition of industrial employment is also forecast to change: lumber, apparel, rubber, and transportation industries are projected to lose employment, while food, fabricated metals, and printing industries are forecast to experience an increase in employment. In total, industrial employment is forecast to grow at an average annual rate of 0.06 percent per year for the 2007-2030 period.

**Table B-15: Number of Industrial Employment**

| Industry | 2000 | 2002 | 2007 | 2030 | 2007-2030 Change |
|---|---|---|---|---|---|
| Food & Tobacco | 91,458 | 87,078 | 87,184 | 88,935 | 1,751 |
| Lumber | 77,229 | 68,820 | 69,190 | 70,835 | 1,646 |
| Paper | 25,091 | 22,513 | 20,622 | 20,911 | 289 |
| Textiles | 5,853 | 5,119 | 4,351 | 4,122 | (229) |
| Apparel | 7,610 | 6,413 | 6,259 | 4,502 | (1,757) |
| Leather | 1,518 | 1,591 | 1,570 | 916 | (654) |
| Furniture | 23,065 | 21,074 | 23,756 | 27,461 | 3,705 |
| Printing | 103,422 | 98,275 | 111,067 | 133,679 | 22,612 |
| Chemicals | 14,002 | 13,140 | 13,618 | 13,682 | 64 |
| Fabricated Metals | 45,474 | 40,124 | 47,439 | 53,785 | 6,346 |
| Petroleum Products | 3,785 | 4,079 | 3,979 | 3,564 | (414) |
| Rubber | 20,846 | 18,584 | 19,920 | 17,401 | (2,520) |
| Stone, Clay, etc. | 18,283 | 17,116 | 20,596 | 21,216 | 620 |
| Machines & Computer | 139,945 | 119,982 | 116,760 | 104,135 | (12,625) |
| Transport Equipment | 112,824 | 93,113 | 98,204 | 81,637 | (16,566) |
| Electric Equipment | 8,381 | 7,238 | 8,851 | 9,758 | 907 |
| Other Manufacturing | 30,197 | 29,628 | 32,259 | 38,451 | 6,192 |
| Total | 728,983 | 653,887 | 685,625 | 694,990 | 9,365 |

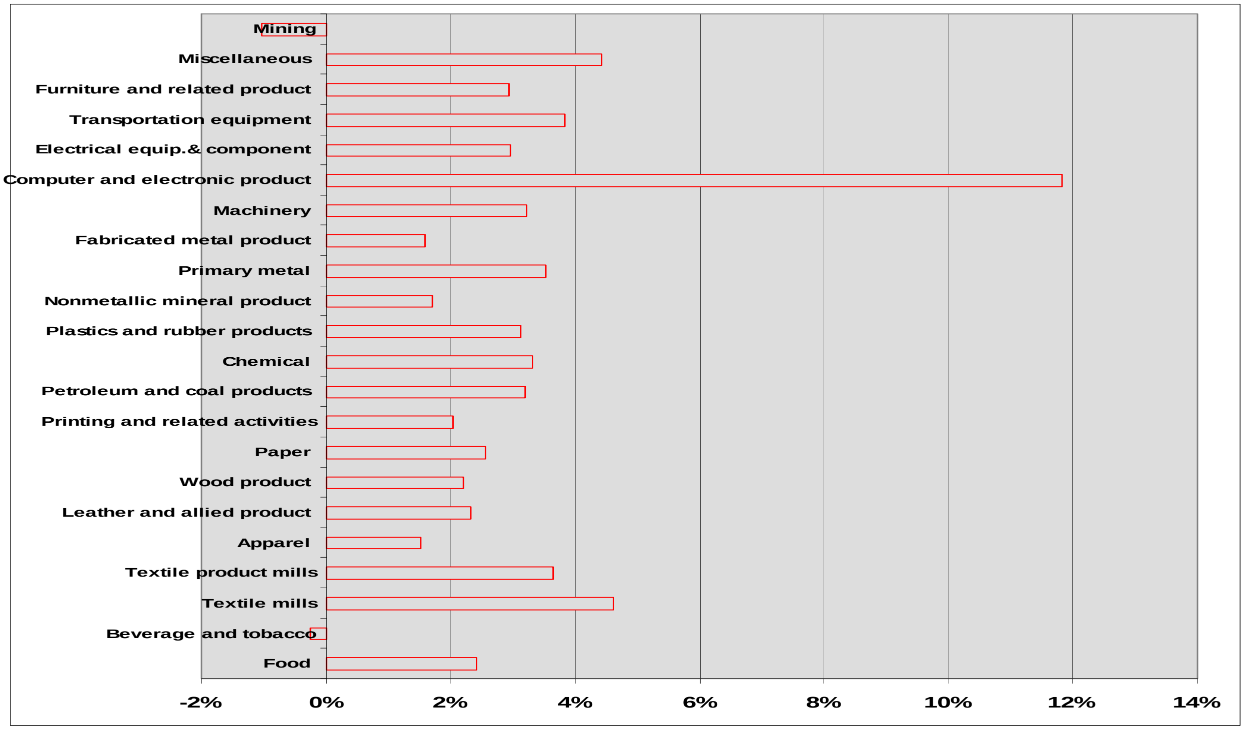
**Figure B-27: Employment in Manufacturing Sectors (number)**




## *Industrial Output*

Industrial output is calculated using industrial employment and output per employee (defined as productivity). The U.S. Bureau of Labor Statistics tracks labor productivity, measured as dollars of output (constant dollars) per unit of labor. The following figure shows the labor productivity index. In most industries, gains in labor productivity have been in excess of 2 percent, with some industries, such as machines and computers, exceeding 10 percent per year. In this analysis, long-term productivity in the manufacturing of machines and computers was capped to 3 percent, reflecting the productivity of a matured industry.

**Figure B-28: National Growth Rate of Labor Productivity 1997-2005**




It should be noted that if information on regional labor productivity were available, it would have been used in this analysis. The following table shows the dollar value of industrial output, which drives demand for this sector.

**Table B-16: Regional Industrial Output (billions of $2000)**

| Regional (millions) | 1985 | 2007 | 2015 | 2020 | 2030 |
|---|---|---|---|---|---|
| Food & Tobacco | 4.15 | 5.20 | 5.98 | 6.42 | 8.50 |
| Textiles | 0.07 | 0.21 | 0.31 | 0.35 | 0.60 |
| Apparel | 0.23 | 0.16 | 0.23 | 0.18 | 0.17 |
| Lumber | 9.79 | 4.52 | 5.39 | 4.93 | 7.19 |
| Furniture | 0.27 | 1.19 | 1.41 | 1.62 | 2.77 |
| Paper | 2.76 | 3.08 | 4.14 | 4.20 | 6.24 |
| Printing | 2.44 | 1.25 | 1.31 | 1.58 | 2.31 |
| Chemicals | 1.42 | 1.58 | 2.00 | 2.19 | 3.12 |
| Petroleum Products | 0.55 | 1.39 | 1.65 | 1.85 | 2.38 |
| Rubber | 0.27 | 1.44 | 1.73 | 1.92 | 2.46 |
| Leather | 0.04 | 0.05 | 0.06 | 0.06 | 0.04 |
| Stone, Clay, etc. | 0.53 | 1.79 | 1.83 | 2.13 | 2.94 |
| Aluminum | 0.32 | 0.45 | 0.50 | 0.64 | 0.87 |
| Other Primary Metals | 0.65 | 1.27 | 1.68 | 1.96 | 3.11 |
| Fabricated Metals | 1.20 | 3.46 | 3.39 | 4.33 | 6.21 |
| Machines & Computer | 2.43 | 42.62 | 51.95 | 58.29 | 71.55 |
| Electric Equipment | 0.36 | 0.95 | 1.07 | 1.37 | 2.12 |
| Transport Equipment | 6.32 | 11.81 | 13.36 | 18.44 | 23.29 |
| Other Manufacturing | 0.38 | 1.92 | 2.29 | 3.12 | 5.78 |
| Agriculture | 4.93 | 12.70 | 14.08 | 16.93 | 24.60 |

Two other sectors are included in the industrial demand for electricity: custom data centers and direct service industries. The demand for electricity from direct service industries is based on projections provided in the BPA White Book 2008 and data from the Chelan Public Utility District. Detailed discussions on the methodology and forecast for both custom data centers and direct service industries are in the demand forecast appendix C.

# ECONOMIC DRIVERS FOR OTHER SECTORS

## *Irrigation*

Demand for electricity for irrigation is linked to agricultural output. A forecast of agricultural output in constant dollars is provided in a state forecast conducted in October, 2008, by Global Insight. Agricultural output in the region is forecast to increase from about $13 billion in 2007 to about $17 billion in 2020 and about $25 billion by 2030.

## *Transportation*

In the current analysis, demand for electricity in the transportation sector is limited to public transportation, such as the Tri-met transportation system or electric buses. The economic driver for this mode of transportation is personal income in the region. The regional income is forecast to grow at an annual rate of 2.9 percent per year, from $405 billion dollars (2000 constant dollars) in 2007 to $782 billion dollars (2000 constant dollars) in 2030.

As part of the sensitivity analysis, the Council will estimate the demand for electricity from plug-in hybrid electric vehicles (PHEV). The key economic driver for the demand for PHEV is the forecast demand for new vehicles, a percentage of which is assumed to be plug-in hybrids. A forecast of new vehicles is provided by Global Insight's October 2009 regional forecast. The market share of PHEVs will depend on consumer consideration of the PHEV purchase price, available incentives, cost of gasoline, and the price of alternative vehicles. A discussion of demand for plug-in hybrid electric vehicles is in the demand forecast chapter 3 and in appendix C.

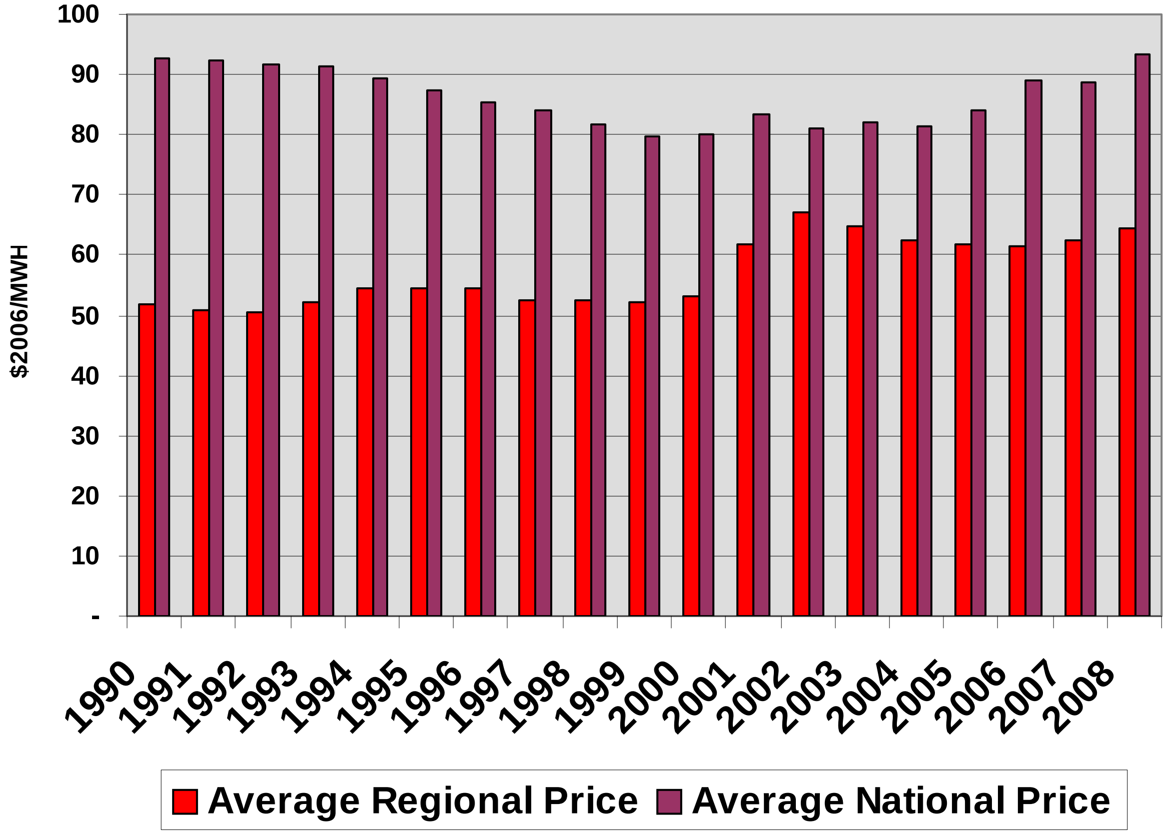
# OTHER ASSUMPTIONS

## *Retail Electricity Prices*

Another factor affecting demand for electricity is its retail price. There are significant differences in electricity prices across the region and among different utilities in the region. To analyze these price differences, the Council used published historic average prices for electricity and other fuel. The average retail price of electricity is calculated for each sector and each state as the ratio of revenue from the sale of electricity (in megawatt hour sales) to that sector.

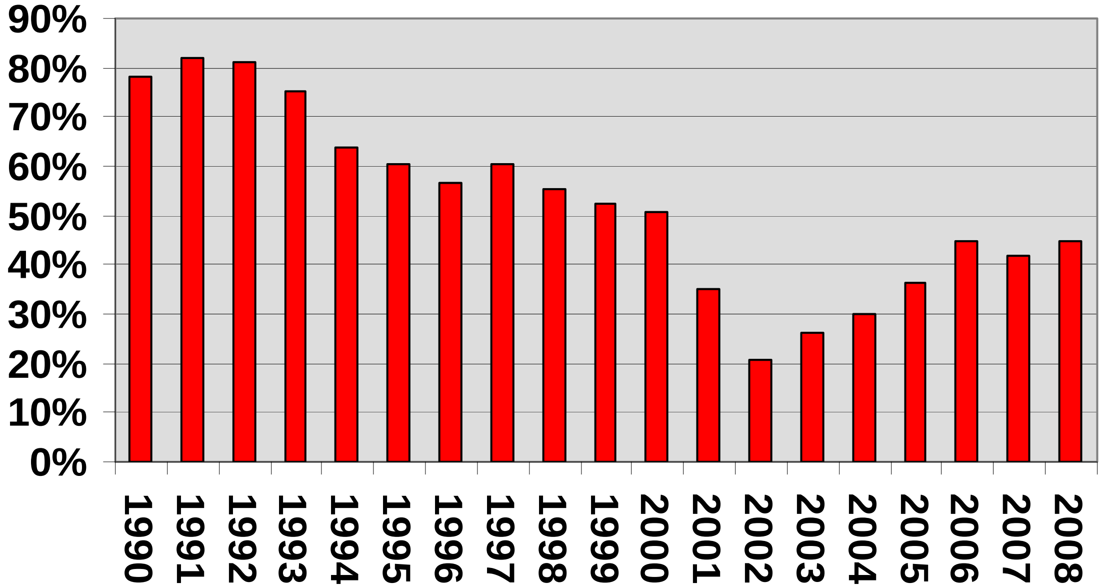
Historically, retail electricity prices in the Northwest have been lower than the national average. This lower price had attracted more energy-intensive industries to the region. However, since the energy crisis in 2000, the price of electricity has been on the rise both regionally and nationally. In the Northwest, it has been growing at a higher rate compared to the nation.

**Figure B-29: Comparison of NW Regional Electricity Price to US Average Price $2006/MWH**




The average electricity price in the nation was about 50-80 percent higher than the regional average price during the1990-2000 period. The difference between these prices narrowed after the energy crisis of 2000-2001, and the region experienced a dramatic loss of industrial load. However, the difference between regional and national prices is growing again due to the increase in oil and gas prices. The national retail price of electricity has been increasing at a higher rate than the regional price, resulting in a growing discrepancy between regional and national prices.

**Figure B-30: Difference Between National and Regional Average Price of Electricity**




## Variations in Price by Sector

The average price of electricity varies across sectors. Typically, residential customers pay a higher price (in part due to higher distribution costs allocated to the residential sector) while commercial and industrial customers typically pay lower rates.

The growth rate of electricity prices across sectors has not been constant over time. During 1990-2000, rate increases were fairly modest. In the late 1990s and early 2000s, the need for new capacity, plus the increase in fuel prices, contributed to an increase in the growth rate of the average price of electricity. During 1990-2000, the nominal price of electricity grew at an average annual rate of 2 percent, with industrial prices growing at a higher rate. Adjusted for inflation, the price of electricity was flat between 1990 and 2000. Since 2000, the growth rate for electricity prices (adjusted for an average inflation rate of 2.5 percent) has been increasing at about twice the inflation rate, growing at an average annual rate of 5.2 percent. The real growth in regional electricity prices was about 3 percent, and nationally around 1.2 percent.

**Table B-17: Average Annual Growth Rate in Retail Electricity Prices**

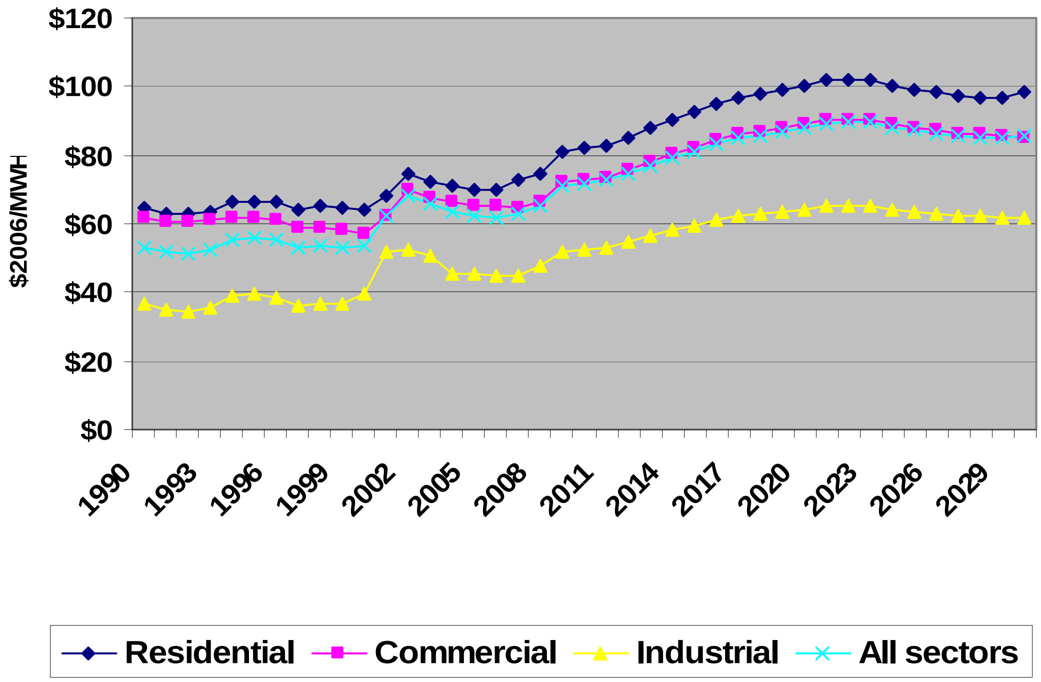
| Northwest | Residential | Commercial | Industrial | All sectors |
|---|---|---|---|---|
| 1990-2000 | 1.7 | 1.1 | 2.6 | 2.0 |
| 2000-2008 | 4.4 | 4.6 | 4.5 | 5.2 |
| | | | | |
| US | | | | |
| 1990-2000 | 0.5 | 0.1 | -0.2 | 0.4 |
| 2000-2008 | 3.2 | 3.4 | 4.4 | 3.7 |

## Forecast of Retail Electricity Prices

Typically, the price of electricity is determined through a regulatory approval process, with utilities bringing a rate proposal to their regulatory body, board of directors or city council, to seek approval of future rates. Rates are dependant on the anticipated cost of serving customers and the level of sales. Sales are determined either for a future period or for a past period. The approved rates should cover the variable *and* fixed-cost components of serving the customers.

The methodology used for forecasting future retail electricity prices in the Sixth Power Plan is a simplified approach, where fixed and variable cost of the power system is estimated for each period and then divided by the volume of sales of electricity. The annual growth rate in average revenue requirement derived from the draft plan, ($0-$100) Least Risk Plan, was applied to sector level electricity prices. More detail on the methodology for projected retail price of electricity can be found on Appendix P of the Sixth Power Plan. Figure B-31 shows the historic 1990-2008 average retail prices and the forecast of average retail rates by sector for the region. The regional rates are anticipated to increase by about 0.9% in the 2010-2030.

**Figure B-31: Average Retail Price of Electricity by Sector**




## Forecast for Retail Electricity Prices by Sector

The estimated price of electricity by sector is presented in the following tables. For the residential sector, the annual real growth rate in electricity prices is expected to be in the 1.5-2.0 percent per year for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, some electric utility rates may be higher or lower than the figures presented here. Also, some utilities may have significantly higher rate increases or decreases than these average state-wide figures would indicate.

**Table B-18: Retail Price of Electricity for Residential Customers ($2006/MWH)**

| | Oregon | Washington | Idaho | Montana |
|---|---|---|---|---|
| **1985** | 74 | 60 | 68 | 74 |
| **1990** | 67 | 62 | 69 | 77 |
| **1995** | 70 | 63 | 68 | 77 |
| **2000** | 69 | 60 | 63 | 76 |
| **2005** | 75 | 68 | 65 | 84 |
| **2010** | 89 | 79 | 74 | 96 |
| **2015** | 101 | 90 | 83 | 109 |
| **2020** | 109 | 97 | 90 | 117 |
| **2030** | 108 | 96 | 89 | 116 |
| **Annual Growth** | | | | |
| **1985-2000** | -0.3% | 0.0% | -0.3% | 0.1% |
| **2000-2007** | 2.9% | 3.9% | 0.3% | 2.7% |
| **2010-2030** | 0.9% | 0.9% | 0.9% | 0.9% |

**Table B-19: Retail Price of Electricity for Commercial Customers ($2006/MWH)**

| | Oregon | Washington | Idaho | Montana |
|---|---|---|---|---|
| **1985** | 81 | 57 | 65 | 67 |
| **1990** | 67 | 56 | 60 | 65 |
| **1995** | 64 | 59 | 57 | 68 |
| **2000** | 60 | 55 | 50 | 61 |
| **2005** | 67 | 65 | 56 | 77 |
| **2010** | 79 | 71 | 60 | 89 |
| **2015** | 89 | 80 | 67 | 101 |
| **2020** | 97 | 86 | 73 | 109 |
| **2030** | 93 | 83 | 70 | 104 |
| **Annual Growth** | | | | |
| **1985-2000** | -1.3% | -0.2% | -1.2% | -0.4% |
| **2000-2007** | 3.2% | 3.6% | -0.3% | 3.5% |
| **2010-2030** | 0.9% | 0.9% | 0.9% | 0.9% |

**Table B-20: Price of Electricity for Industrial Customers ($2006/MWH)**

| | Oregon | Washington | Idaho | Montana |
|---|---|---|---|---|
| **1985** | 56 | 34 | 42 | 40 |
| **1990** | 44 | 34 | 37 | 40 |
| **1995** | 44 | 38 | 36 | 44 |
| **2000** | 42 | 39 | 37 | 47 |
| **2005** | 50 | 44 | 40 | 50 |
| **2010** | 51 | 55 | 45 | 60 |
| **2015** | 58 | 62 | 51 | 67 |
| **2020** | 63 | 67 | 55 | 73 |
| **2030** | 60 | 64 | 53 | 70 |
| **Annual Growth** | | | | |
| **1985-2000** | -1.3% | 0.6% | -0.6% | 0.7% |
| **2000-2007** | 4.8% | 3.2% | -0.1% | 8.1% |
| **2010-2030** | 0.9% | 0.9% | 0.9% | 0.9% |

## *Other Fuel Prices*

The demand for electricity is not only affected by the price of electricity, but also the price of alternative fuels. If the price of electricity relative to natural gas is decreasing, one would expect the consumption of electricity to increase and natural gas to decrease. Consumers could substitute natural gas for electricity, and or decrease their demand for natural gas. Consumer's fuel choices are influenced by relative fuel prices. Demand for electricity is affected by the competition between alternative fuels.

This section covers the current assumptions for the retail prices of natural gas and electricity. For each fuel, a base price and a regional delivery charge is calculated. The base, or wholesale commodity, price for each fuel is from the Council's fuel price forecast, discussed in Appendix A. Delivery charges vary by sector and state. Historic and forecast prices for the three main kinds of fuel are shown in the following tables. To be consistent with retail electricity price calculations, the forecasted retail fuel prices also include impact of CO2 tax. To put the fuel on a comparable basis, prices are shown in constant 2006 dollars per million Btu.

**Table B-21: Oregon Sector Level Fuel Prices ($2006/mmBTU)**

| Sector and Fuel | 1985 | 2000 | 2007 | 2010 | 2020 | 2030 | 2010-2030 Growth Rate |
|---|---|---|---|---|---|---|---|
| Residential Electricity | 21.72 | 20.22 | 24.6 | 26.0 | 31.8 | 31.0 | 0.88% |
| Residential Natural Gas | 10.65 | 9.24 | 13.6 | 8.5 | 9.7 | 11.4 | 1.47% |
| Residential Oil | 11.08 | 11.57 | 4.3 | 4.3 | 4.6 | 5.2 | 0.99% |
| Commercial Electricity | 23.68 | 17.6 | 21.9 | 23.1 | 28.3 | 27.5 | 0.88% |
| Commercial Natural Gas | 9.6 | 7.37 | 11.5 | 6.4 | 7.5 | 8.9 | 1.60% |
| Industrial Electricity | 16.33 | 12.23 | 16.9 | 15.0 | 18.3 | 17.8 | 0.88% |
| Industrial Natural Gas | 7.36 | 5.61 | 8.7 | 4.1 | 5.0 | 6.0 | 1.89% |

**Table B-22: Washington Sector Level Fuel Prices ($2006/mmBTU)**

| Sector and Fuel | 1985 | 2000 | 2007 | 2010 | 2020 | 2030 | 2010-2030 Growth Rate |
|---|---|---|---|---|---|---|---|
| Residential Electricity | 17.64 | 17.64 | 23.0 | 23.1 | 28.3 | 27.5 | 0.88% |
| Residential Natural Gas | 10.05 | 8.06 | 13.5 | 8.3 | 9.5 | 11.1 | 1.49% |
| Residential Oil | 12.29 | 13.02 | 3.8 | 3.8 | 4.1 | 4.6 | 0.98% |
| Commercial Electricity | 16.73 | 16.11 | 20.6 | 20.7 | 25.3 | 24.6 | 0.88% |
| Commercial Natural Gas | 8.3 | 6.78 | 12.0 | 6.8 | 7.8 | 9.3 | 1.58% |
| Industrial Electricity | 9.86 | 11.36 | 14.1 | 15.9 | 19.5 | 19.0 | 0.88% |
| Industrial Natural Gas | 7.25 | 4.51 | 9.5 | 5.9 | 6.9 | 8.2 | 1.65% |

**Table B-23: Idaho Sector Level Fuel Prices ($2006/mmBTU)**

| Sector and Fuel | 1985 | 2000 | 2007 | 2010 | 2020 | 2030 | 2010-2030 Growth Rate |
|---|---|---|---|---|---|---|---|
| Residential Electricity | 19.95 | 18.53 | 18.9 | 21.5 | 26.3 | 25.6 | 0.88% |
| Residential Natural Gas | 10.4 | 7.19 | 11.0 | 7.0 | 8.1 | 9.5 | 1.56% |
| Residential Oil | 11.54 | 10.39 | 2.3 | 2.4 | 2.5 | 2.9 | 0.94% |
| Commercial Electricity | 19.15 | 14.55 | 14.2 | 17.4 | 21.3 | 20.7 | 0.88% |
| Commercial Natural Gas | 8.59 | 6.27 | 10.2 | 6.2 | 7.3 | 8.6 | 1.62% |
| Industrial Electricity | 12.18 | 10.7 | 10.6 | 13.2 | 16.2 | 15.8 | 0.88% |
| Industrial Natural Gas | 6.83 | 4.6 | 8.9 | 4.8 | 5.7 | 6.8 | 1.78% |

**Table B-24: Montana Sector Level Fuel Prices ($2006/mmBTU)**

| Sector and Fuel | 1985 | 2000 | 2007 | 2010 | 2020 | 2030 | 2010-2030 Growth Rate |
|---|---|---|---|---|---|---|---|
| Residential Electricity | 21.8 | 22.32 | 26.9 | 28.0 | 34.4 | 33.4 | 0.88% |
| Residential Natural Gas | 7.63 | 6.91 | 9.7 | 6.8 | 7.9 | 9.3 | 1.57% |
| Residential Oil | 12.54 | 9.85 | 1.0 | 1.1 | 1.2 | 1.3 | 0.81% |
| Commercial Electricity | 19.77 | 17.98 | 22.8 | 25.9 | 31.8 | 30.9 | 0.88% |
| Commercial Natural Gas | 8.07 | 6.76 | 9.5 | 6.6 | 7.7 | 9.1 | 1.59% |
| Industrial Electricity | 11.63 | 13.64 | 23.5 | 17.4 | 21.3 | 20.7 | 0.88% |
| Industrial Natural Gas | 7.46 | 8.51 | 9.6 | 6.4 | 7.5 | 8.8 | 1.61% |

On average, the growth rate in fuel prices is anticipated to be slower in the forecast period than they were historically, in part due to extraordinary high prices experienced in 2008. Natural gas price increases are expected to be lower in the forecast period than they were in the historic period. However, the year-by-year increase in prices presents a more accurate picture of change in the cost of fuel. The year-by-year data on fuel prices is available in the companion Excel workbook. The following graphs show the historic and forecast fuel prices for each state.

**Figure B-32: Oregon Sectoral Fuel Prices ($ 2006/MMBTU)**

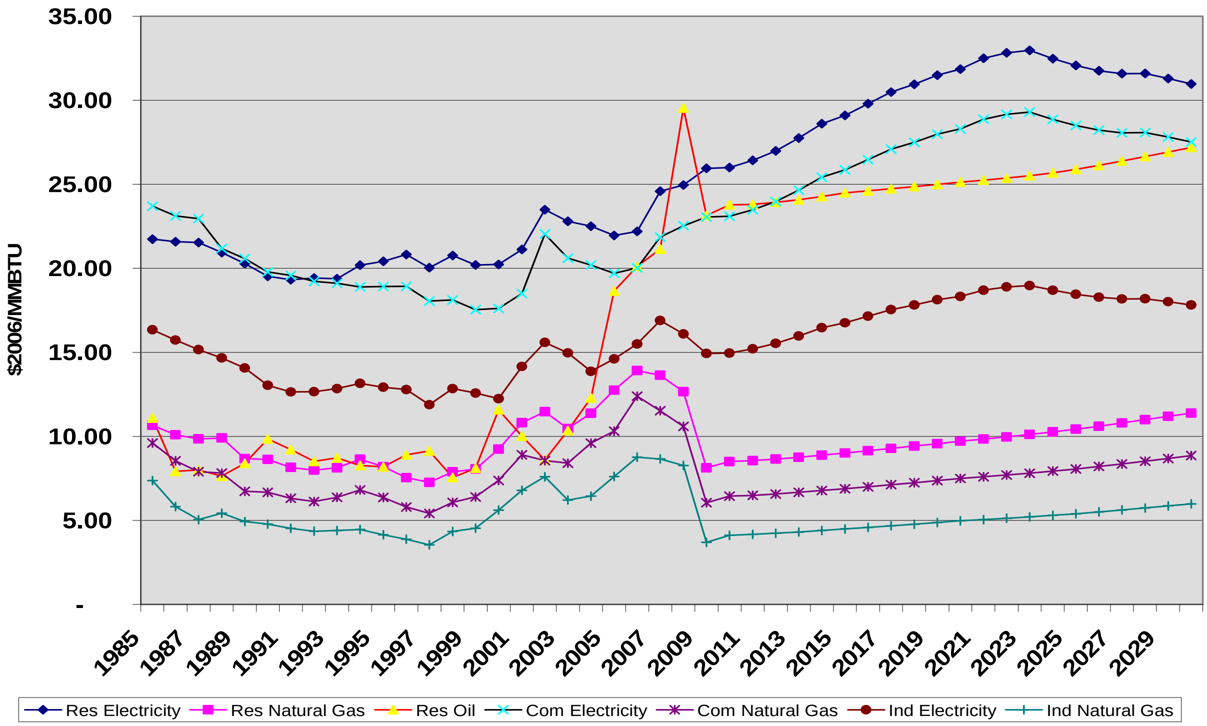


**Figure B-33: Washington Sectoral Fuel Prices ($ 2006/MMBTU)**

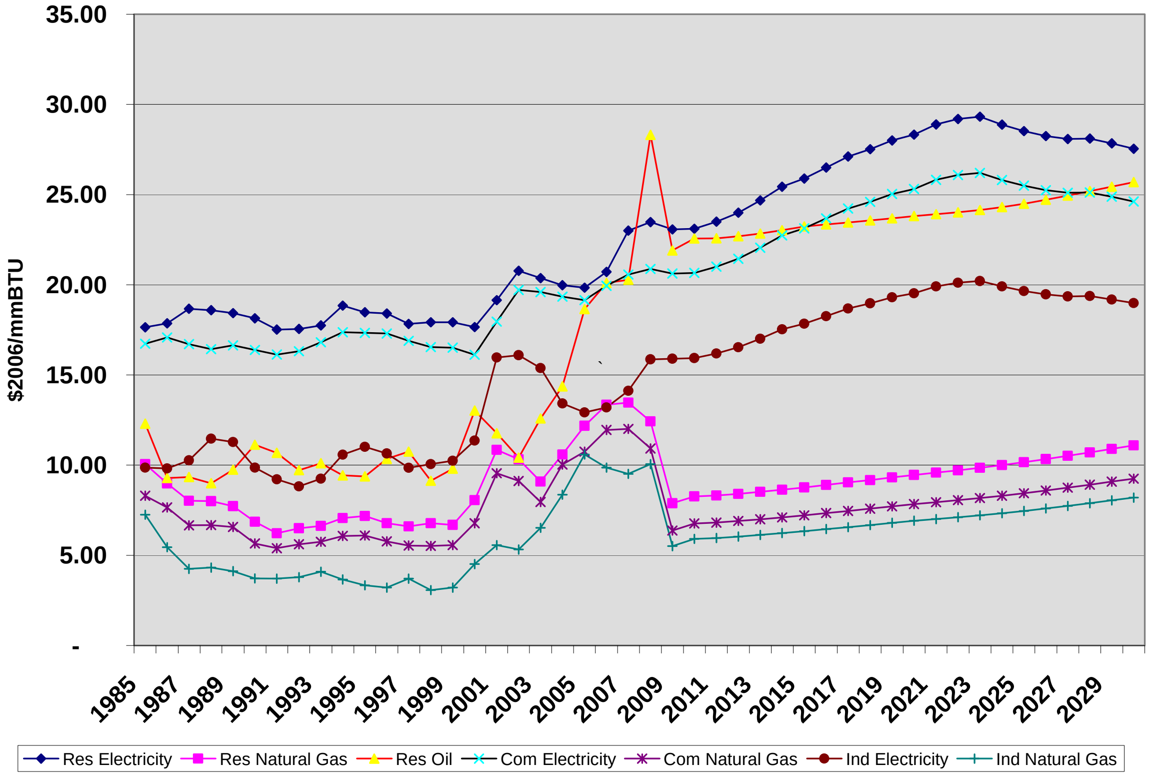



**Figure B-34: State of Idaho Sectoral Fuel Prices ($ 2006/MMBTU)**

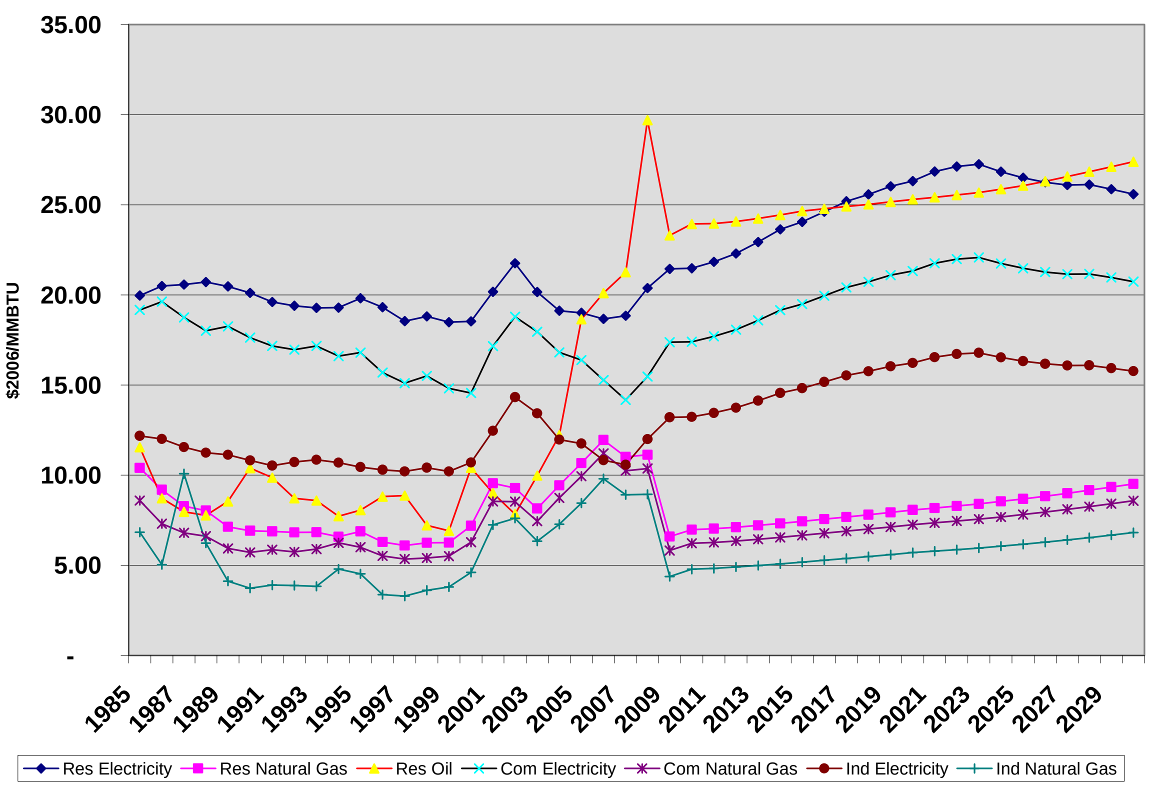


**Figure B-35: State of Montana Sectoral Fuel Prices ($ 2006/MMBTU)**

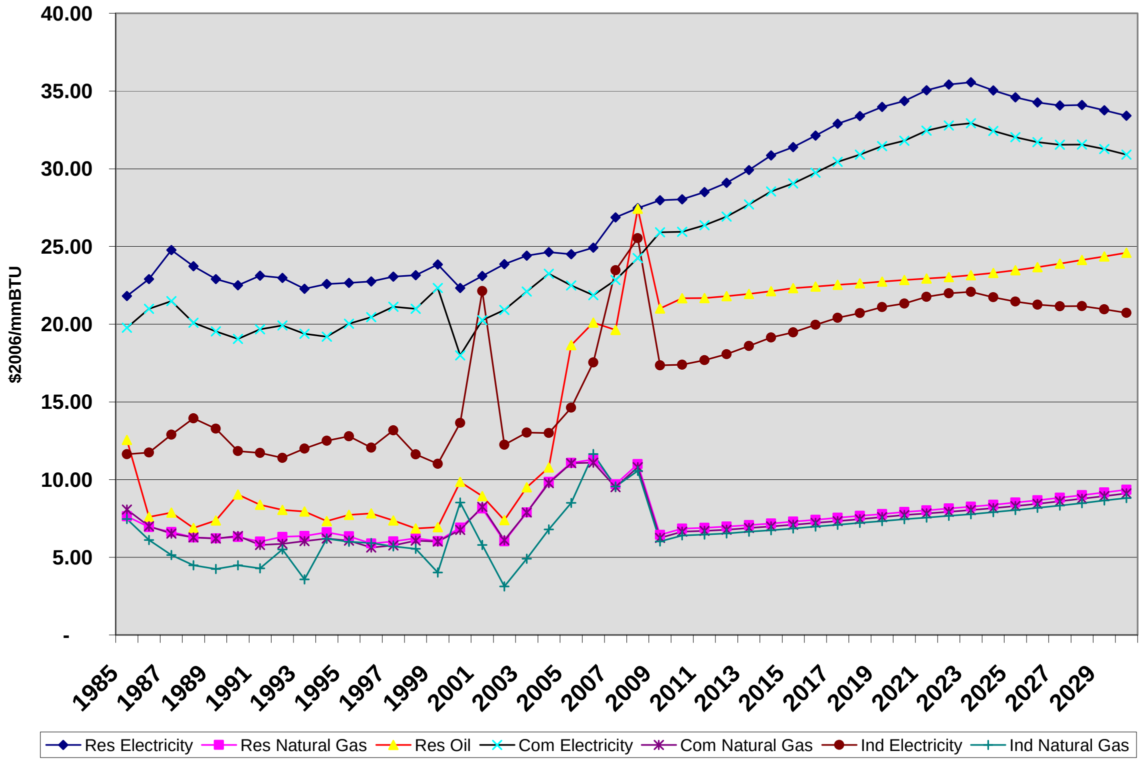



**Table B-25: Growth Rate in Retail Electricity Price**

| Price of Electricity (2006 $/ MWH) | 1985-2007 | 2000-2007 | 2010-2030 |
|---|---|---|---|
| **Oregon-Residential** | 0.60% | 2.90% | 0.88% |
| **Oregon-Commercial** | -0.40% | 3.20% | 0.88% |
| **Oregon-Industrial** | 0.20% | 4.80% | 0.88% |
| **Washington-Residential** | 1.20% | 3.90% | 0.88% |
| **Washington-Commercial** | 1.00% | 3.60% | 0.88% |
| **Washington-Industrial** | 1.70% | 3.20% | 0.88% |
| **Idaho-Residential** | -0.20% | 0.30% | 0.88% |
| **Idaho-Commercial** | -1.30% | -0.30% | 0.88% |
| **Idaho-Industrial** | -0.60% | -0.10% | 0.88% |
| **Montana-Residential** | 1.00% | 2.70% | 0.88% |
| **Montana-Commercial** | 0.70% | 3.50% | 0.88% |
| **Montana-Industrial** | 3.30% | 8.10% | 0.88% |

# SUMMARY OF ECONOMIC DRIVERS FOR THE SIXTH POWER PLAN

The following summary table shows the annual growth rate for the historic and forecast period for each state and the region. In general, the key economic drivers reflect a slow down in economic growth for 2010-2030.

**Table B-26: Historic and Forecast of Annual Growth Rate by Sector**

| | | Oregon | | Washington | | Idaho | | Montana | | Region | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Sector | Business/Building type | 1985-2007 | 2010-2030 | 1985-2007 | 2010-2030 | 1985-2007 | 2010-2030 | 1985-2007 | 2010-2030 | 1985-2007 | 2010-2030 |
| Residential (Number of household stock) | Single Family | 1.6% | 1.4% | 1.9% | 1.2% | 2.4% | 1.9% | 0.9% | 0.9% | 1.8% | 1.3% |
| | Multi Family | 2.4% | 1.6% | 2.6% | 1.6% | 2.5% | 2.0% | 1.6% | 2.2% | 2.5% | 1.7% |
| | Other Family | 3.0% | 1.1% | 2.7% | 1.1% | 2.5% | 0.9% | 1.9% | 0.9% | 2.7% | 1.0% |
| Commercial ( square footage Stock) | Large Office | 2.0% | 1.2% | 1.3% | 1.6% | 5.7% | 1.4% | 0.3% | 1.2% | 1.5% | 1.5% |
| | Medium Office | 4.6% | 1.2% | 3.9% | 1.6% | 8.6% | 1.4% | 2.7% | 1.2% | 4.1% | 1.5% |
| | Small Office | 2.5% | 1.2% | 1.8% | 1.6% | 6.3% | 1.4% | 0.7% | 1.2% | 2.1% | 1.5% |
| | Big Box-Retail | 8.6% | 0.8% | 8.6% | 0.7% | 13.0% | 0.8% | 8.6% | 0.8% | 8.8% | 0.8% |
| | Small Box-Retail | 1.1% | 0.8% | 1.3% | 0.7% | 4.5% | 0.8% | 1.2% | 0.8% | 1.4% | 0.8% |
| | High End-Retail | 1.1% | 0.8% | 1.0% | 0.7% | 4.5% | 0.8% | 1.2% | 0.8% | 1.2% | 0.8% |
| | Anchor-Retail | 0.4% | 0.8% | 0.4% | 0.7% | 4.2% | 0.8% | 0.5% | 0.8% | 0.6% | 0.8% |
| | K-12 | 3.5% | 0.7% | 1.9% | 1.1% | 3.3% | 0.7% | 1.1% | 0.8% | 2.2% | 1.0% |
| | University | 3.6% | 0.9% | 1.8% | 1.2% | 2.9% | 0.9% | 1.8% | 0.7% | 2.1% | 1.1% |
| | Warehouse | 2.6% | 1.6% | 4.3% | 3.5% | 3.9% | 2.5% | 1.3% | 1.5% | 3.3% | 2.7% |
| | Supermarket | 0.6% | 0.4% | 0.9% | 0.5% | 3.2% | 0.4% | 1.0% | 0.3% | 1.1% | 0.4% |
| | Mini Mart | 6.4% | 0.6% | 6.2% | 1.0% | 9.2% | 1.2% | 6.6% | 0.6% | 6.7% | 0.9% |
| | Restaurant | 1.1% | 1.0% | 1.4% | 1.2% | 3.7% | 1.6% | 1.0% | 1.0% | 1.4% | 1.2% |
| | Lodging | 1.6% | 0.4% | 2.2% | 0.7% | 2.4% | 0.7% | 0.7% | 0.3% | 1.7% | 0.5% |
| | Hospital | 3.7% | 1.0% | 1.9% | 1.1% | 3.0% | 1.2% | 2.3% | 0.6% | 2.5% | 1.0% |
| | Other Health | 3.6% | 1.1% | 2.0% | 2.0% | 2.1% | 1.6% | 2.9% | 1.5% | 2.4% | 1.7% |
| | Assembly | 3.6% | 2.1% | 2.1% | 0.8% | 3.2% | 2.9% | 1.7% | 2.2% | 2.5% | 1.4% |
| | Other | 3.7% | 0.7% | 2.3% | 0.3% | 3.4% | 0.7% | 1.5% | 1.0% | 2.6% | 0.5% |
| Industrial (output) | Food & Tobacco | 2.0% | 2.3% | 0.9% | 1.7% | -0.5% | 1.3% | 1.4% | 2.9% | 1.0% | 1.9% |
| | Textiles | 1.6% | 4.0% | 7.1% | 5.3% | 13.9% | 4.6% | 16.1% | 3.9% | 4.8% | 4.8% |
| | Apparel | -1.7% | -2.0% | -1.3% | -5.0% | -2.6% | 5.6% | -4.6% | 2.5% | -1.6% | -4.1% |
| | Lumber | -4.0% | 0.6% | -2.9% | 2.6% | -2.8% | 0.8% | -2.8% | 0.4% | -3.4% | 1.3% |
| | Furniture | 7.7% | 3.9% | 6.5% | 5.3% | 8.1% | 5.1% | 6.4% | 4.5% | 7.1% | 4.7% |
| | Paper | 0.1% | 1.1% | 0.8% | 1.7% | 0.2% | 0.5% | 0.7% | 3.5% | 0.5% | 1.5% |
| | Printing | -2.2% | 1.5% | -3.2% | 5.4% | -3.6% | 2.1% | -5.6% | 2.2% | -3.0% | 3.4% |
| | Chemicals | 5.4% | 2.9% | -1.3% | 3.2% | 0.4% | -2.0% | 3.0% | 4.1% | 0.5% | 1.9% |
| | Petroleum Products | -2.5% | 1.4% | 6.3% | 2.4% | 3.3% | 3.3% | -2.7% | 2.3% | 4.3% | 2.4% |
| | Rubber | 9.3% | 1.6% | 9.4% | 2.2% | 1.3% | 4.1% | 9.3% | 5.8% | 7.9% | 2.2% |
| | Leather | 2.1% | -0.7% | 2.1% | -2.2% | -0.3% | -3.8% | -5.3% | -0.5% | 1.4% | -1.5% |
| | Stone, Clay, etc. | 5.9% | 2.9% | 6.2% | 3.9% | 4.7% | 2.9% | 2.4% | 1.0% | 5.7% | 3.4% |
| | Aluminum | 4.0% | -1.1% | 1.3% | 0.8% | | | -4.6% | 0.3% | 1.5% | 0.5% |
| | Other Primary Metals | 4.0% | 2.9% | 1.3% | 0.8% | 12.0% | 7.9% | -4.6% | 0.3% | 3.1% | 2.4% |
| | Fabricated Metals | 3.7% | 2.2% | 6.0% | 3.3% | 5.0% | 4.2% | 6.8% | 2.7% | 4.9% | 3.0% |
| | Machines & Computer | 15.8% | 0.8% | 7.6% | 1.8% | 19.0% | 2.0% | 14.9% | 3.1% | 13.9% | 1.2% |
| | Electric Equipment | 0.9% | 3.7% | 8.0% | 4.9% | 2.3% | 3.5% | -1.9% | 10.4% | 4.6% | 4.6% |
| | Transport Equipment | 2.7% | 4.2% | 2.8% | 1.4% | 9.3% | 3.9% | 5.8% | 5.7% | 2.9% | 1.7% |
| | Other Manufacturing | 8.3% | 5.0% | 6.6% | 5.9% | 12.2% | 7.0% | 8.3% | 4.4% | 7.6% | 5.6% |
| Mining | Mining | 4.9% | 2.0% | 4.2% | -0.1% | 7.1% | 5.3% | 3.7% | 2.5% | 3.9% | 2.8% |
| Agriculture | Agriculture | 3.8% | 5.2% | 4.0% | 2.2% | 3.1% | 3.9% | 6.4% | 3.2% | 4.4% | 3.6% |
| Transportation * | Passenger | 3.3% | 2.9% | 3.8% | 2.9% | 3.2% | 3.1% | 2.7% | 2.4% | 3.6% | 2.9% |
| | Freight | 3.1% | 3.7% | 3.3% | 3.4% | 5.6% | 5.6% | 2.4% | 2.9% | 3.3% | 3.8% |
| | Off Road | 1.4% | 0.5% | 1.4% | -1.0% | -0.5% | -0.4% | 1.7% | 0.8% | 1.5% | -0.3% |

# ALTERNATIVE ECONOMIC SCENARIOS

Because future economic conditions are highly uncertain, the forecasts encompass a wide range of possibilities for future economic growth. The demand forecast includes three alternative sets of economic drivers. In the medium case, discussed earlier, the key economic drivers project a healthy regional economy (albeit with a slower growth path than in the recent past). In addition to the plan case, two alternative scenarios are considered, one representing a low-economic-growth scenario and the other a high-growth projection of the future.

The low-growth scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slow down in labor productivity, and a low inflation rate. On the other hand, the high-case scenario assumes faster economic growth, stronger demand for energy, higher prices for fossil fuel, sustained growth in labor productivity, and a higher inflation rate.

In all scenarios it is assumed that climate change concerns, demand for cleaner fuel, and a national cap-and-trade or a $CO_2$ tax push fuel prices higher. Cost of $CO_2$ emissions is assumed to start at $8 dollars per tons in 2012 and climb to about $27 dollars by 2020 and by the end of forecast period, 2030, to reach $47 dollars per ton.

To estimate the low and high range for each key variable for each year, the base value for the driver was multiplied by an annual factor that increases the value (for the high case) or reduces it (for the low case). For example, if the medium case value for new floor space additions for warehouses were 100,000 square feet, for the low-growth scenario the 100,000 square feet is lowered by 6 percent, and for the high-growth scenario it is increased by 12 percent. The 6 percent and 12 percent figures are averages; the actual percentage values used in the model vary by year. The following two figures show the range of percent change from the medium case scenario for each commercial building type and each industry. Similar methodology is used in developing each key economic driver.

**Figure B-36: Range of Percent Change from Medium Case - for Commercial Buildings**

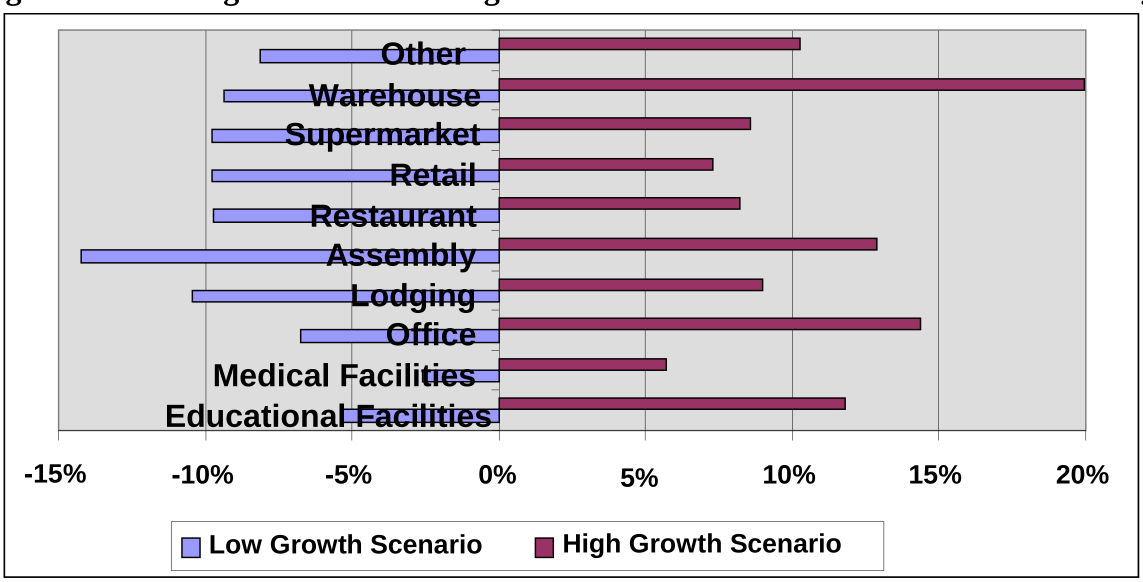
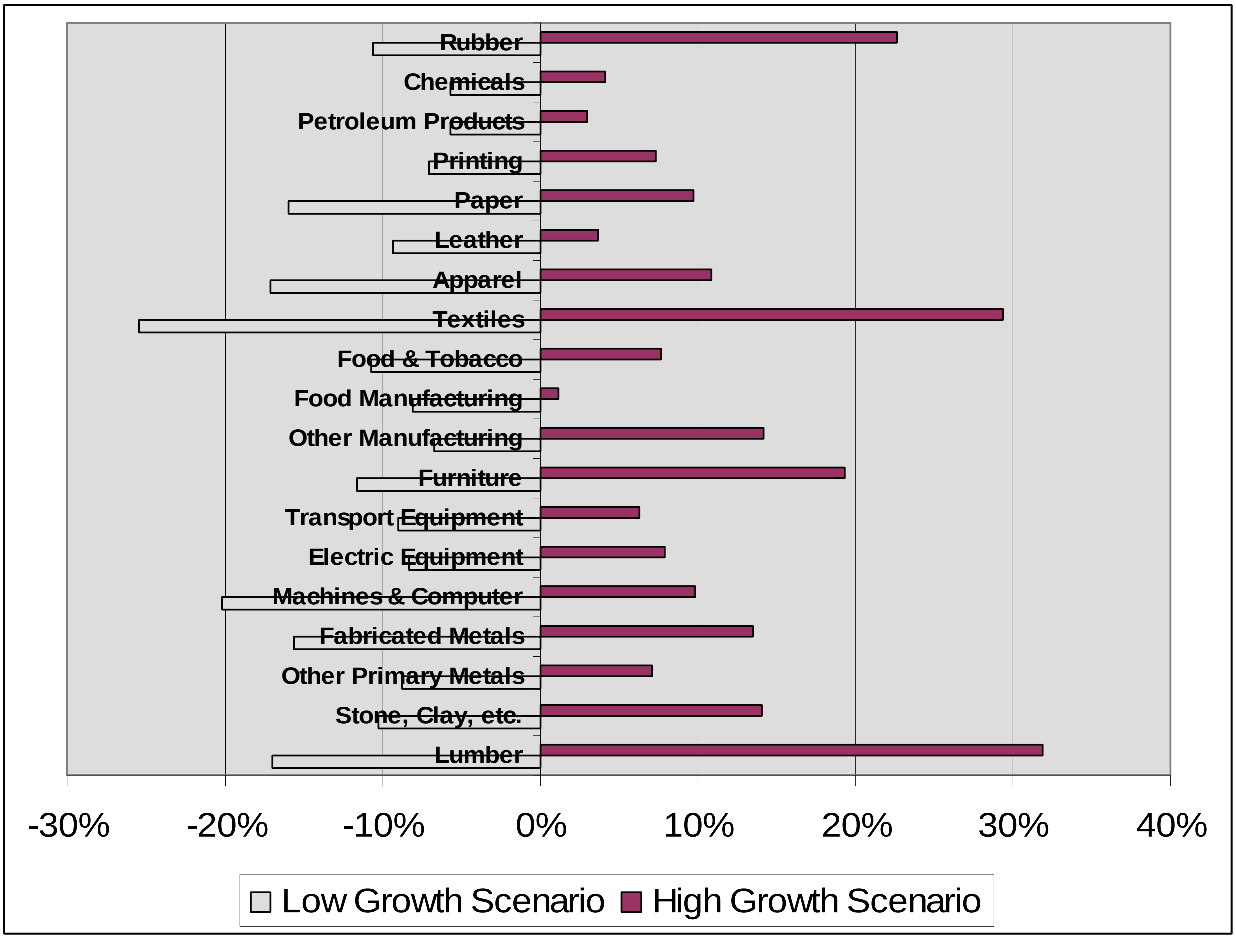


**Figure B-37: Range of Percent Change from Medium Case- for Industrial Sectors**




The average annual growth rates presented above are summary values. The demand forecasting system, however, uses the year-by-year values rather than the annual average values. The source of the range forecast used in the Sixth Power Plan, is Global Insight's long-term national forecast, October 2009.

The following table shows the growth rate for each sector at a more aggregate level. The price range for oil, natural gas, and coal are based on the Council's Sixth Power Plan.

**Table B-27: Historic, Medium Case and Alternative Growth Rates**

| Key Economic Drivers | 1985-2007 (Actual) | 2010-2030 (Low) | 2010-2030 (Medium) | 2010-2030 (High) |
|---|---|---|---|---|
| **Population** | 1.60% | 0.49% | 1.20% | 1.5% |
| **Residential Units** | 1.90% | 0.49% | 1.40% | 1.5% |
| **Commercial Floor Space** | 2.30% | 0.67% | 1.20% | 1.43% |
| **Manufacturing Output $** | 4.10% | 0.00% | 1.70% | 2.11% |
| **Agriculture Output $** | 4.40% | 3.00% | 3.60% | 4.20% |
| **Light Vehicle Sales** | - | 2.52% | 2.40% | 3.05% |
| **Inflation Rate** | 2.20% | 2.70% | 1.70% | 1.50% |
| **Average Annual Growth Rate in Price (2010-2030)*** | | | | |
| **Oil Prices** | 1.70% | -1.00% | 1.04% | 2.30% |
| **Natural Gas Prices** | 1.80% | 0.90% | 2.80% | 3.50% |
| **Coal Prices** | -4.80% | -0.50% | 0.50% | 1.20% |

* Fuel price assumptions are consistent with the Council's fuel price and electricity price forecast.

Additional Details: A companion Excel workbook containing details on the economic drivers is available from Council's website.

# Appendix C: Demand Forecast

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## ENERGY DEMAND

### *Background*

It has been 26 years, a mere generation, since the Council released its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the Northwest Power Act, regional electricity load was growing at 3.5 percent per year and load (excluding the direct service industries) grew at an annual rate of 4.3 percent. In 1970, regional load was about 11,000 average megawatts, and during that decade demand grew by about 4,700 average megawatts. During the 1980s, load growth slowed significantly but continued to grow at about 1.5 percent per year, experiencing load growth of about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts was added to the regional load, making load growth in the last decade of 20th century about 1.1 percent. Since 2000, regional load has declined. As a result of the energy crisis of 2000-2001 and the recession of 2001-2002, regional load decreased by 3,700 average megawatts between 2000 and 2001. Loss of many of the aluminum and chemical companies that were direct service industries contributed to this load reduction. Since 2002, however, regional load has been on an upswing, growing at an annual rate of 2.5 percent. This growth has been driven by increasing demand from commercial and residential sectors. Figure C-1 and Table C-1 track the regional electricity sales from 1970-2007.

**Figure C-1: Total and Non-DSI Regional Electricity Sales (MWa)**

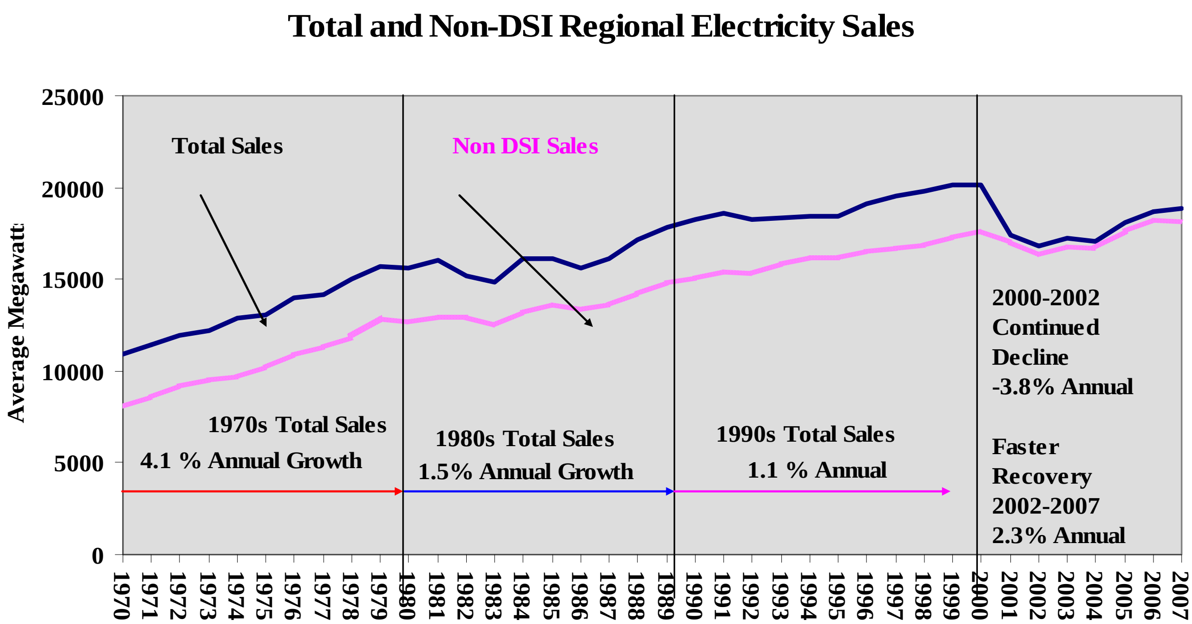



**Table C-1: Total and Non-DSI Regional Electricity Sales**

| Annual Growth | Total Sales | Non DSI |
|---|---|---|
| **1970-1979** | 4.1% | 5.2% |
| **1980-1989** | 1.5% | 1.7% |
| **1990-1999** | 1.1% | 1.5% |
| **2000-2007** | -0.8% | 0.5% |
| **2002-2007** | 2.5% | 2.2% |

The dramatic decrease in the growth of electricity demand shown in Table C-1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less energy-intensive activities. As shown in Table C-2, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes, increasing electricity prices, and regional and national conservation efforts.

**Table C-2: Changing Electric Intensity of the Regional Economy**

| Year | Non-DSI Electricity Use Per Capita (MWa / Thousand Persons) |
|---|---|
| 1985 | 1.50 |
| 1990 | 1.57 |
| 2000 | 1.52 |
| 2007 | 1.45 |

For the most part, the upswing in load since 2002 has been due to growth in residential- and commercial-sector sales. By the end of 2007, the residential sector had added about 888 average megawatts to load, the commercial sector 285 average megawatts, while the industrial sector lost 337 megawatts.

In the past two decades, the region's population has grown from roughly 9 million in 1985 to more than 12.6 million in 2007. This growth rate surpasses the national population growth rate by almost 40 percent. Typically, this level of increase in population would put significant pressure on the electricity demand. However, due to regional conservation investments and a shift to less energy-intensive industries, the region's demand for electricity has remained stable. For example, during the years 1990-2007, the U.S. population grew at an annual rate of 0.9 percent, while residential demand for electricity grew at 2.4 percent. In the Northwest, the average growth rate in population was 1.3 percent, while the residential demand for electricity grew at an annual rate of 1.4 percent, a full percentage point below the national average. Similar patterns can be observed in the commercial sector.

## *Demand Forecast Methodology*

When the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of its historically rapid growth of electricity use, and it began to question the future of several proposed nuclear and coal generating plants. To respond to these changes, it was important that the Council's demand forecasting system (DFS) be able to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends, used in the past, were no longer reliable indicators of future demand.

In addition, the Northwest Power Act requires the Council to consider conservation a resource, and to evaluate it along with new generation. So, the DFS analysis also needs to support a detailed evaluation of energy efficiency improvements and their effects on electricity demand.

Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that incorporates end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models requires detailed separate economic forecasts for all the sectors represented in the demand models. The models also required forecasts of demographic trends, electricity prices, and fuel prices.

As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to emerge, it became clear that the Council needed to understand the pattern of electricity demand over seasons, months, and hours of the day. The load shape forecasting system (LSFS) was developed to do this. The model identifies what kinds of equipment are contributing to demand and how much electricity they are using, which helps build the hourly shape of demand.

These new detailed approaches of the DFS and LSFS were expensive and time consuming to develop, and were not used in the Fifth Power Plan. Although the Northwest Power Act still requires a 20-year forecast of demand, changes in the electricity industry have meant a greater focus on the short-term energy landscape. Rather than large-scale nuclear and coal plants, popular in the early 1980s, other resources that do not take as long to plan and develop are being chosen and built, so the need to analyze their impact on the power system is critical. In addition, the Council's centralized planning role is less clear as a restructured wholesale electricity market relies more on competitively developed resources.

The focus of the Council's power planning activity now includes evaluating the performance of more a competitive power market, and how the region should acquire conservation in this new market. The Council is also concerned about the ability of competitive wholesale power markets to provide adequate and reliable power supplies, which has implications for demand forecasting.

One of the most significant issues facing the region's power system today is that the pattern of electricity demand has changed. The question is not only if we have energy to meet annual demand, but whether we have adequate capacity to meet times of peak demand. The Pacific Northwest now resembles the rest of the West, which has always been capacity constrained. The region can now expect peak prices during Western peak demand periods. In response, the Sixth Power Plan is focused on shorter-term electricity demand.

Additionally, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and the adequacy of supply are now determined by West-wide electricity conditions. The Council uses the AURORA® electricity market model, which requires assumptions about demand growth for all areas of the Western-integrated electricity grid.

Given all these changes, the demand forecast needs to be able to analyze short-term, temporal patterns of demand and expanded geographic areas. As well, any forecast must address the effect of energy-efficiency improvements on the power system. Finding new ways to assess conservation potential, or to encourage its adoption without explicit estimates of the electricity likely to be saved, is a significant issue for regional planning.

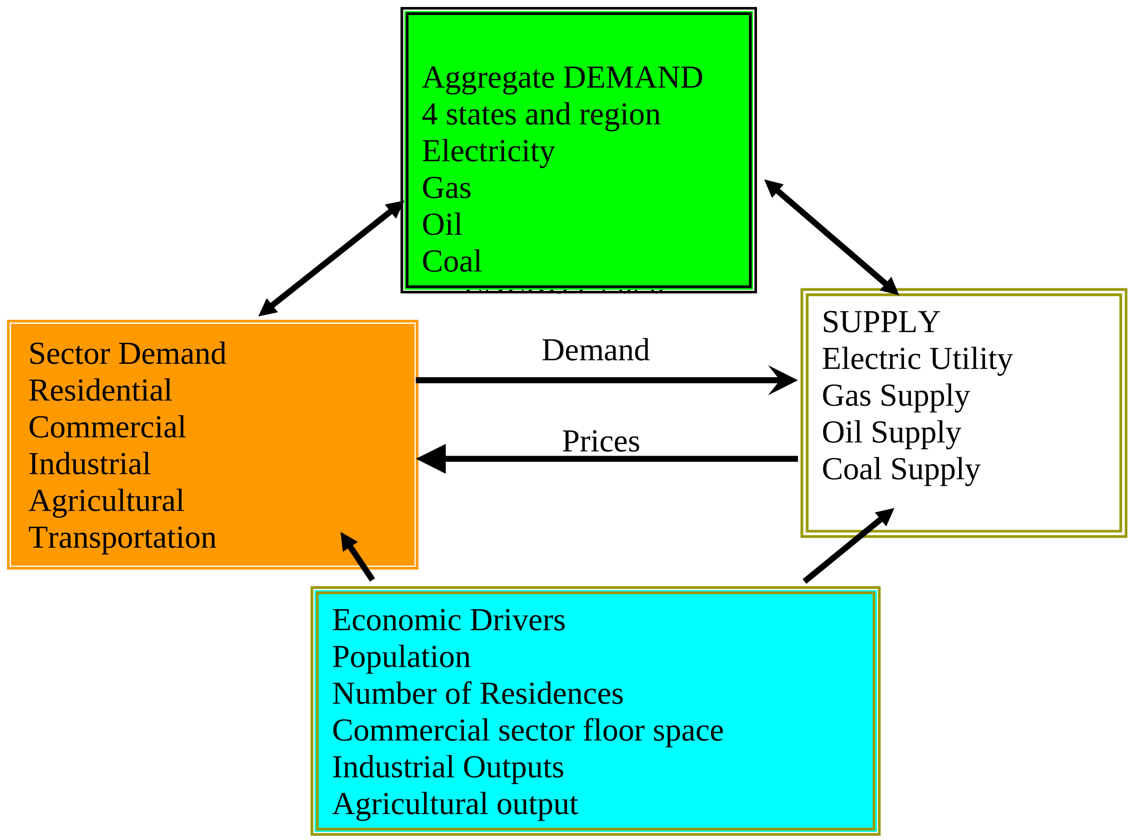
Previous Council forecasts for individual sectors have been quite accurate. The level of residential consumption was overestimated by an average of 0.6 percent. Commercial consumption was underestimated by an average of 0.9 percent, and industrial consumption, excluding direct service industries (DSI), was overestimated by an average of 3.6 percent. Long-term forecasts did not depart seriously from actual electricity consumption, so the Fifth Power Plan relied on earlier forecast trends for non-DSI electricity demand. However, the Sixth Power Plan updates the demand forecasting system.

## New Demand Forecasting Model for the Sixth Plan

The 2000-2001 Western energy crisis created renewed interest in demand forecasting, and the Northwest's changing load shape has created a particular concern about capacity supply. In order to forecast these peaks, the Council relies on end-use forecasting models. For its Sixth Power Plan, the Council selected a new end-use forecasting and policy analysis tool. The new demand forecasting system (DFS), based on the Energy 2020 model, generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is fully integrated and includes fuel, sectors, and end-use load. The Council uses Energy 2020 to forecast annual and peak load for electricity as well as for other fuel. The following flow-chart provides an overview of the Energy 2020 model.

**Figure C-2: Overview of Council's Long Term Forecasting Model**




The DFS is calibrated to total demand for electricity, natural gas, oil, and a range of other fuel. The data for calibration is obtained from the Energy Information Administration's State Energy Demand System (SEDS). Annual consumption data for each sector and state is available for years 1960-2006. To add the year 2007, additional information from monthly electricity sales reports for electricity, natural gas, and oil consumption was used. The Energy 2020 model used detailed information from the previous version of the DFS to create a bridge between the old Council modeling system and the new modeling system.

The basic version of Energy 2020 was expanded to make sure that the DFS can meet the needs of conservation resource planning. The number of sectors and end-uses was increased. In the residential sector, three building types, four different space-heating technologies, and two different space-cooling technologies were tracked. Demand was tracked for electricity for 12 end-uses in the residential sector. New end-uses were added, like information, communication, and entertainment (ICE) devices, which in earlier forecasts did not have a major share of electricity consumption in homes. Technology trade-off curves were updated with new cost and efficiency data.

In the commercial sector, the model was expanded to forecast load for 18 different commercial building types. Forecasts for commercial floor space development made sure that the economic drivers of the demand forecast for electricity and the economic drivers for the conservation resource assessment were identical.

The industrial sector of the model was updated with new regional energy consumption data. The work on the industrial sector is ongoing and the results of a recent analysis on industrial demand for electricity were added to the demand forecast. The load shape forecasting system was updated with the best available data on end-use load shape to forecast peak demand, including monthly peaks. This will enable the Council to demonstrate a closer link among the demand forecasting system, the hydro modeling, and the Regional Portfolio Model (RPM).

## *Demand Forecast*

The Council's medium or "Plan" case predicts electricity demand to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030. The average annual rate of growth over that period in this forecast is about 1.2 percent per year. This level of growth does not take into account expected demand reductions due to new conservation measures. This rate is consistent with the Council's Fifth Power Plan growth rate, which was projected to grow by 1.4 percent per year from 2000 to 2025. The winter peak demand for power is projected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030, at an average annual growth rate of 1.0 percent. The summer peak demand for power is projected to grow from 29,000 megawatts in 2010 to 40,000 megawatts by 2030, at an annual growth rate of 1.6 percent.

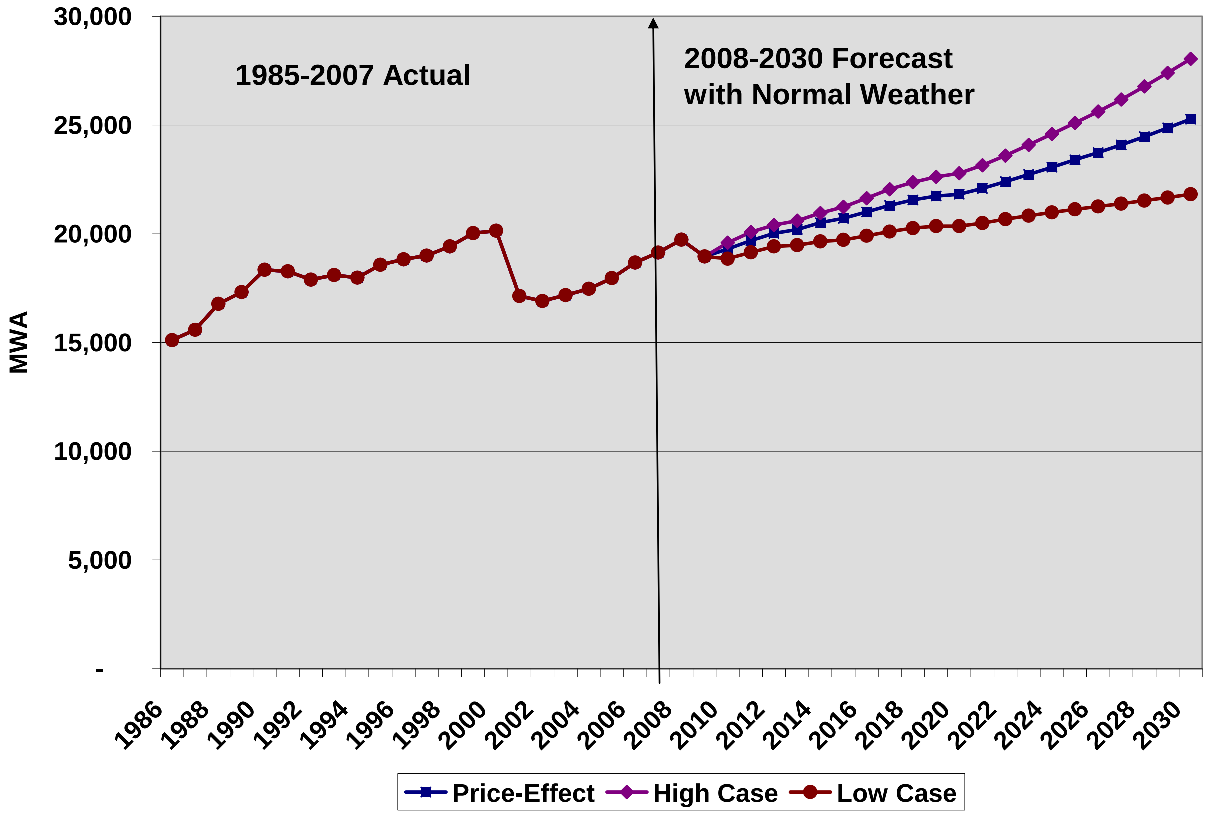
Total non-DSI consumption of electricity is forecast to grow from about 18,000 average megawatts in 2007 to over 18,600 average megawatts by 2010 and close to 25,000 average megawatts by 2030. This is an average annual growth rate of 1.4 percent for the years 2010-2030. The following table shows the forecast for each sector in the medium case. Each sector's forecast is discussed in separate subsections of this appendix.

**Table C-3: Medium Case Sector Forecast of Annual Energy MWa**

| | 2007 Actual | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Residential** | 7,424 | 7,499 | 8,335 | 9,987 | 1.06% | 1.44% |
| **Commercial** | 6,129 | 6,705 | 8,214 | 9,170 | 2.05% | 1.58% |
| **Industrial Non-DSI** | 3,904 | 3,724 | 3,715 | 4,360 | -0.03% | 0.79% |
| **DSI** | 764 | 693 | 772 | 772 | 1.09% | 0.54% |
| **Irrigation** | 848 | 599 | 696 | 873 | 1.52% | 1.90% |
| **Transportation** | 71 | 72 | 87 | 113 | 1.91% | 2.27% |
| **Total Non-DSI** | 18,376 | 18,599 | 21,048 | 24,503 | 1.24% | 1.39% |
| **Total** | 19,140 | 19,292 | 21,820 | 25,275 | 1.24% | 1.36% |

The medium case electricity demand forecast predicts that the region's electricity consumption will grow, absent any conservation, by about 6,000 average megawatts by 2030, an average annual increase of about 270 average megawatts. The projected growth reflects increased electricity use by the residential and commercial sectors and reduced growth in the industrial sector, particularly by energy-intensive industries. Higher electricity and natural gas prices have had a tremendous impact on the region's industrial makeup. As a result of the 2000-2001 energy crisis and the recession of 2001-2002, the region lost about 3,500 megawatts of industrial demand, which it has not regained. The region is projected to surpass the 2000 level of demand by 2013. However, the depth of the 2008 recession may delay this recovery.

**Figure C-3: Sixth Power Plan Range of Demand Forecasts (MWa)**

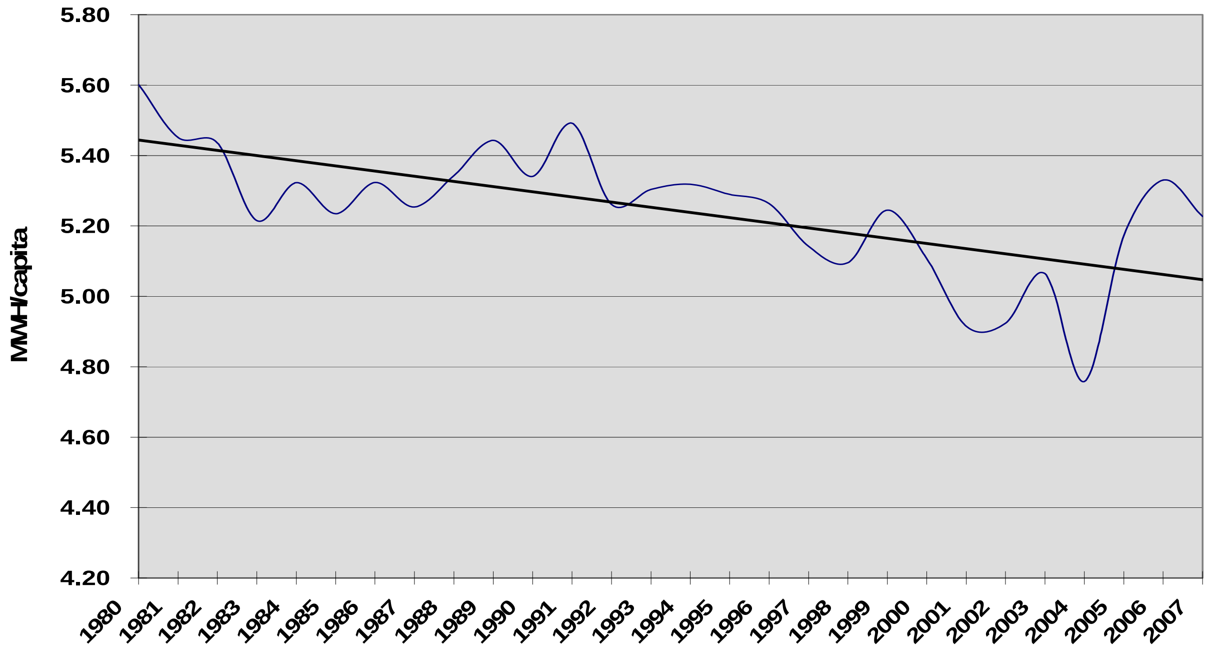



## Residential Sector Demand

### *History*

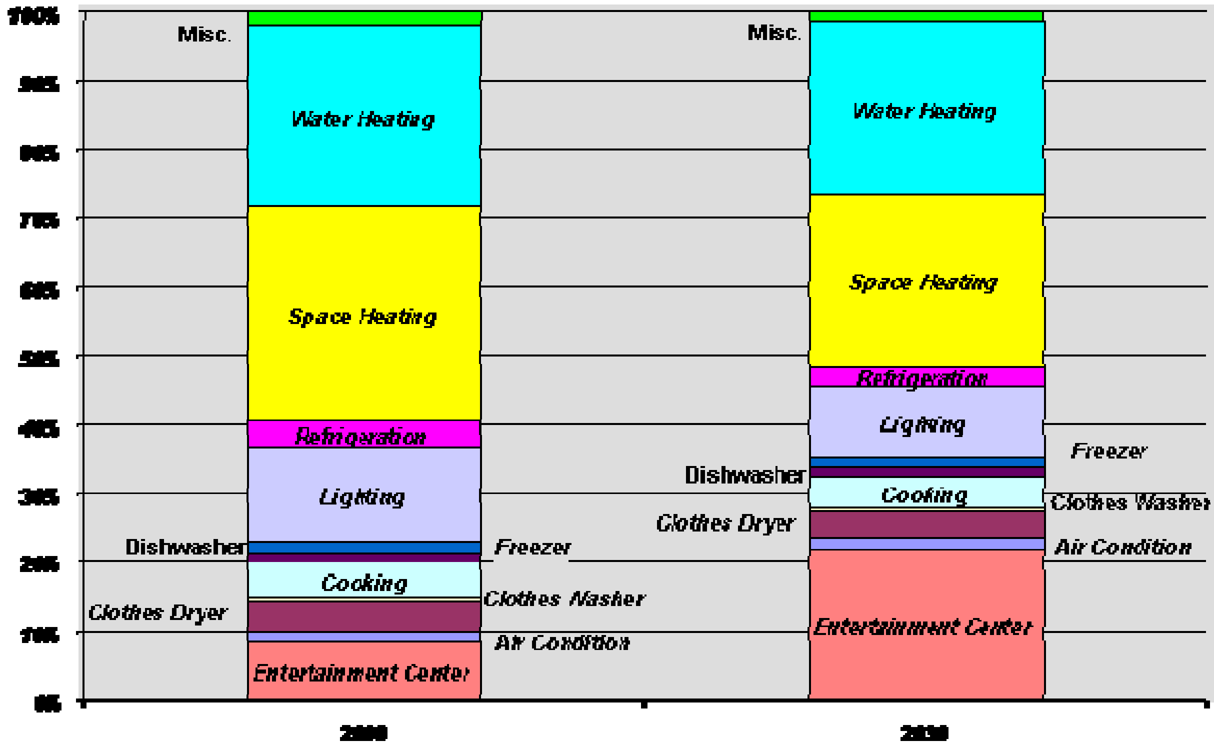
Demand for electricity in the residential sector grew from 5,350 average megawatts in 1986 to about 7,400 average megawatts in 2007. Although residential demand for electricity has been increasing, the per capita consumption of electricity in the residential sector was declining or stable until about 2005 when per capita electricity consumption began to grow. Improved building codes and more efficient appliances helped to keep the consumption level down. Per capita consumption (adjusted for weather) for the region, as well as the overall trend, is shown in the following graph.

**Figure C-4: Change in Residential Per Capita Consumption**




The drop in residential per capita consumption of electricity is even more significant when considering the tremendous increase in home electronics that did not even exist 25 years ago. The demand for information, communication, and entertainment (ICE) appliances has sky-rocketed and is expected to continue. The following graph shows the share of residential sector electricity consumption by end-use. The share of air-conditioning and ICE doubles between 2008 and 2030.

**Figure C-5: Breakdown of Residential Electricity Consumption by End-use**

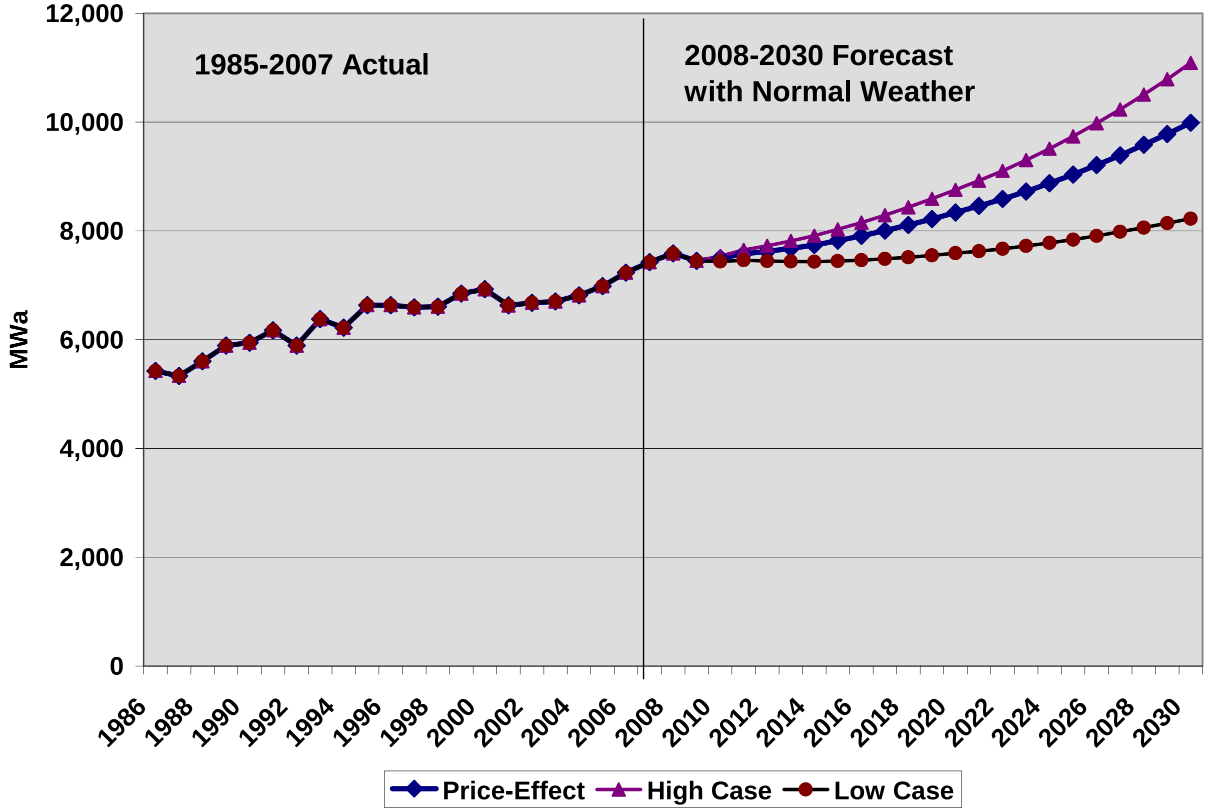



### *Residential Demand Forecast*

For the medium case scenario, residential electricity consumption is forecast to grow by 1.4 percent between 2010 and 2030. This growth rate is consistent with the levels anticipated in the Fifth Power Plan, which estimated the growth rate for the residential sector to be 1.36 percent per year between the years 2000 and 2025. The Sixth Power Plan predicts that for 2008-2030, residential sector demand will increase by an average of about 125 megawatts per year. This forecast does not incorporate the effect of new conservation investments.

Note: There is a companion Excel workbook, available from the Council website, with the details of Sixth Power Plan load forecast.

**Figure C-6: Forecast Residential Electricity Sales**

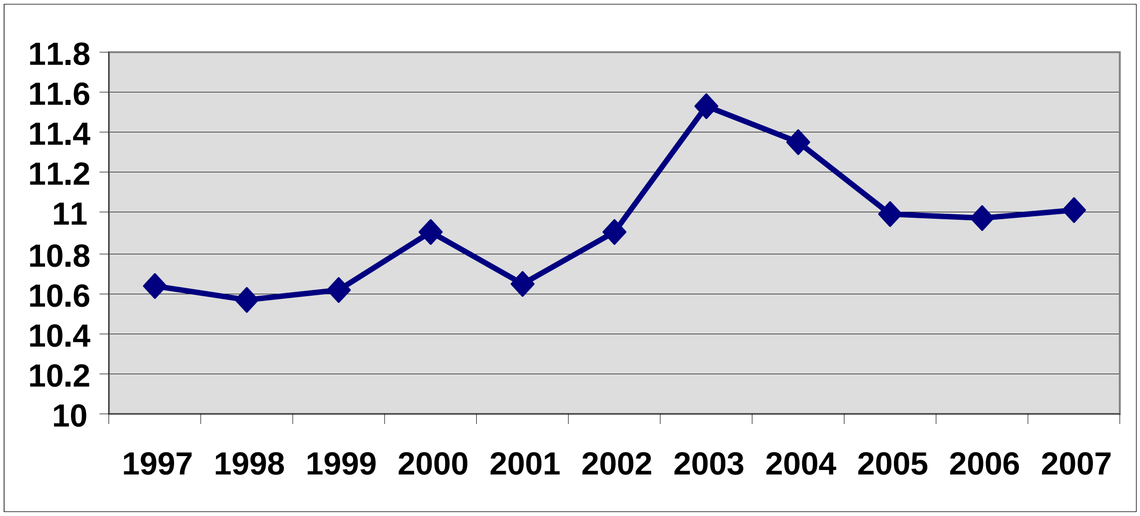



## Commercial Sector Demand

### *History*

Electricity demand in the commercial sector has increased regionally and nationally. In 1986, demand in the commercial sector of the region was about 4,000 average megawatts and by 2007 this sector required more than 6,000 average megawatts. Electricity intensity in the sector has also increased. Electricity intensity in the commercial sector is measured in kilowatt hours used per square foot. In 1997, the commercial sector's average electricity intensity was about 10.6 kilowatt hours per square foot. By 2003, it had increased to about 11.6 kilowatt hours per square foot. Since 2003, however, the intensity of electricity use in the commercial sector has been declining or has remained stable. The commercial sector also includes street lighting, traffic lights and load from municipal public facilities such as sewer treatment facilities.

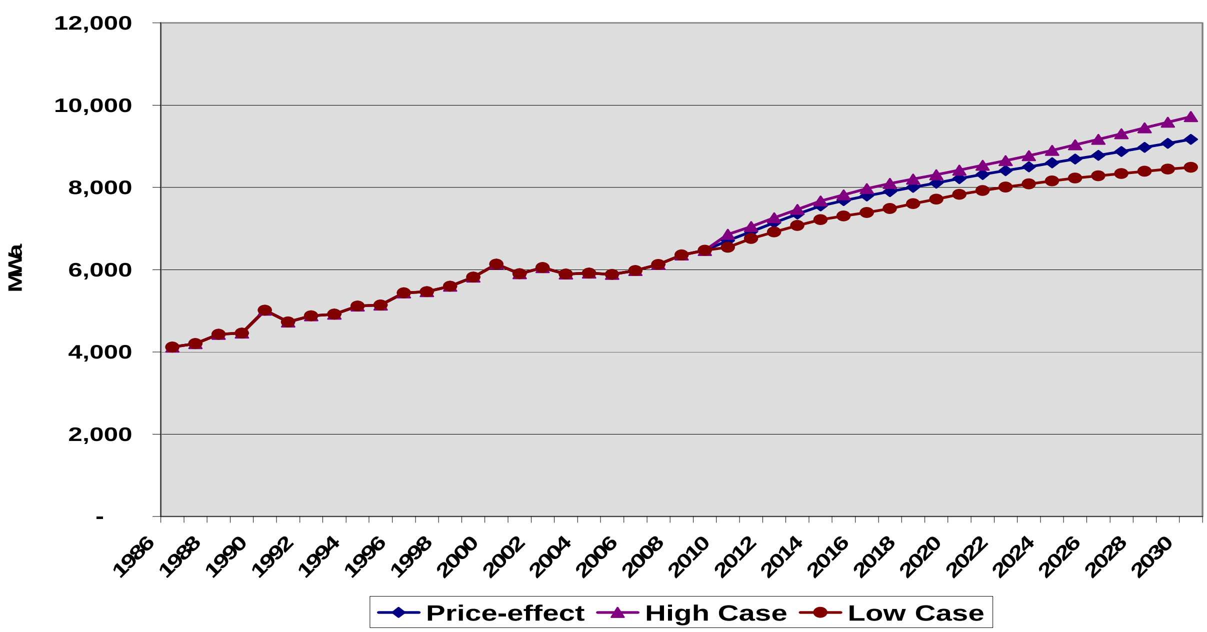
**Figure C-7: Electricity Intensity in the Commercial Sector (kWh/SQF)**




### *Commercial Demand Forecast*

Commercial sector electricity consumption is forecast to grow by 1.6 percent per year between 2010 and 2030. During this period, demand is expected to grow from 6,700 average megawatts to about 9,000 average megawatts. This rate of increase is higher than the 1.18 percent per year that was forecast in the Fifth Power Plan. The following figure illustrates the forecast. On average, this sector's predicted demand adds about 110 average megawatts per year during 2010 and 2030.

**Figure C-8: Forecast Commercial Electricity Sales**




## Non-DSI Industrial Sector

Industrial electricity demand is difficult to confidently forecast. It differs from residential and commercial sector demand where energy is used mostly for buildings and is reasonably uniform and easily related to household growth and employment. By contrast, industrial electricity use is extremely varied, and demand tends to be concentrated in relatively few very large, often specialized, uses instead of spread among many relatively uniform uses.

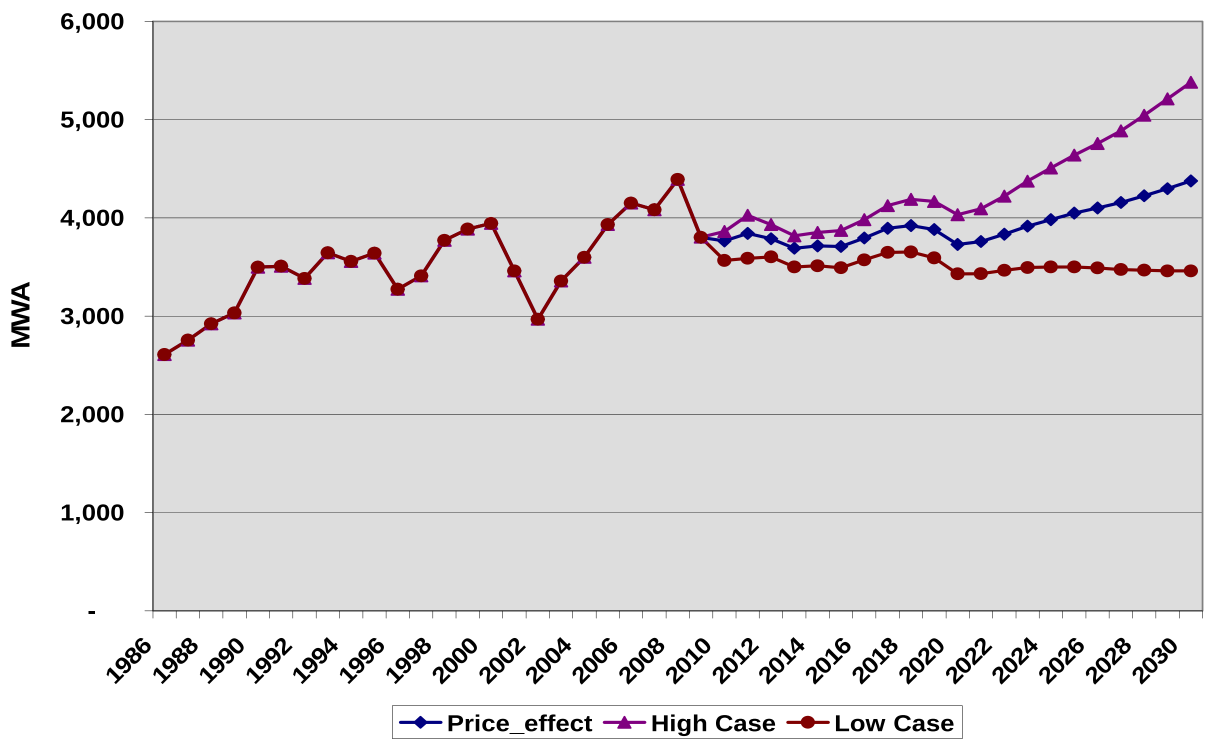
The non-DSI industrial sector demand is dominated by pulp and paper, food processing, chemical, primary metals other than aluminum, and lumber and wood products industries. Many of these industries have declined or are experiencing slow growth. These traditional resource-based industries are becoming less important to regional electricity demand forecasts, while new industries, such as semiconductor manufacturing, are growing faster and commanding a growing share of the industrial-sector load.

In the Sixth Power Plan, non-DSI industrial consumption is forecast to grow at 0.8 percent annually. Electricity consumption in this sector is forecast to grow from 3,900 average megawatts in 2007 to 4,360 in 2030. The non-DSI industries' demand peaked in 1999 reaching 4,000 average megawatts. Starting with the 2000-2001 energy crisis and the recession that followed, non-DSI consumption went down to about 3,700 average megawatts by the start of 2008.

**Table C-4: Changing Electric Intensity of Industries in the Northwest**

| Year | Non-DSI Electricity Intensity (MWh/Industrial employees) |
|---|---|
| **1985** | 59.2 |
| **1990** | 58.3 |
| **2000** | 56.4 |
| **2002** | 48.7 |
| **2007** | 46.8 |

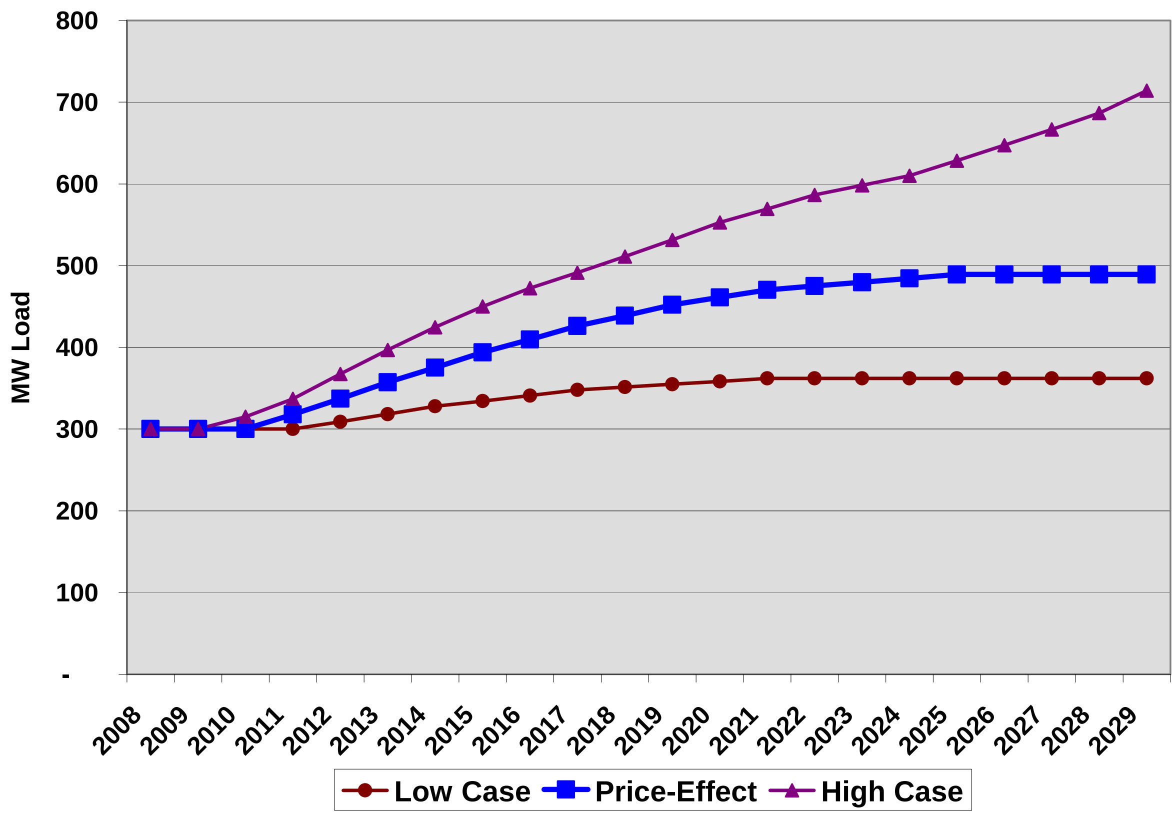
**Figure C-9: Forecast Industrial Non-DSI Electricity Sales**



### *Custom Data Centers*

The non-DSI industrial load sector includes custom data centers. These centers are also known as data "farms" and "service centers" and support Internet services like the well-known Amazon.com or Google.com. These businesses do not manufacture a tangible product, but because they are typically on an industrial rate schedule and because of their size, they are categorized as industrial load. The region currently provides about 300 average megawatts to these types of businesses. The demand for services from this sector is forecast to increase by about 7 percent per year. However, there are many opportunities to increase energy efficiency in custom data centers. As a result, the demand forecast for these centers is adjusted to an annual growth rate of about 3 percent. Background and additional assumptions on custom data centers are presented at the end of this appendix.

**Figure C-10: Projected Load (MW) from Custom Data Centers**

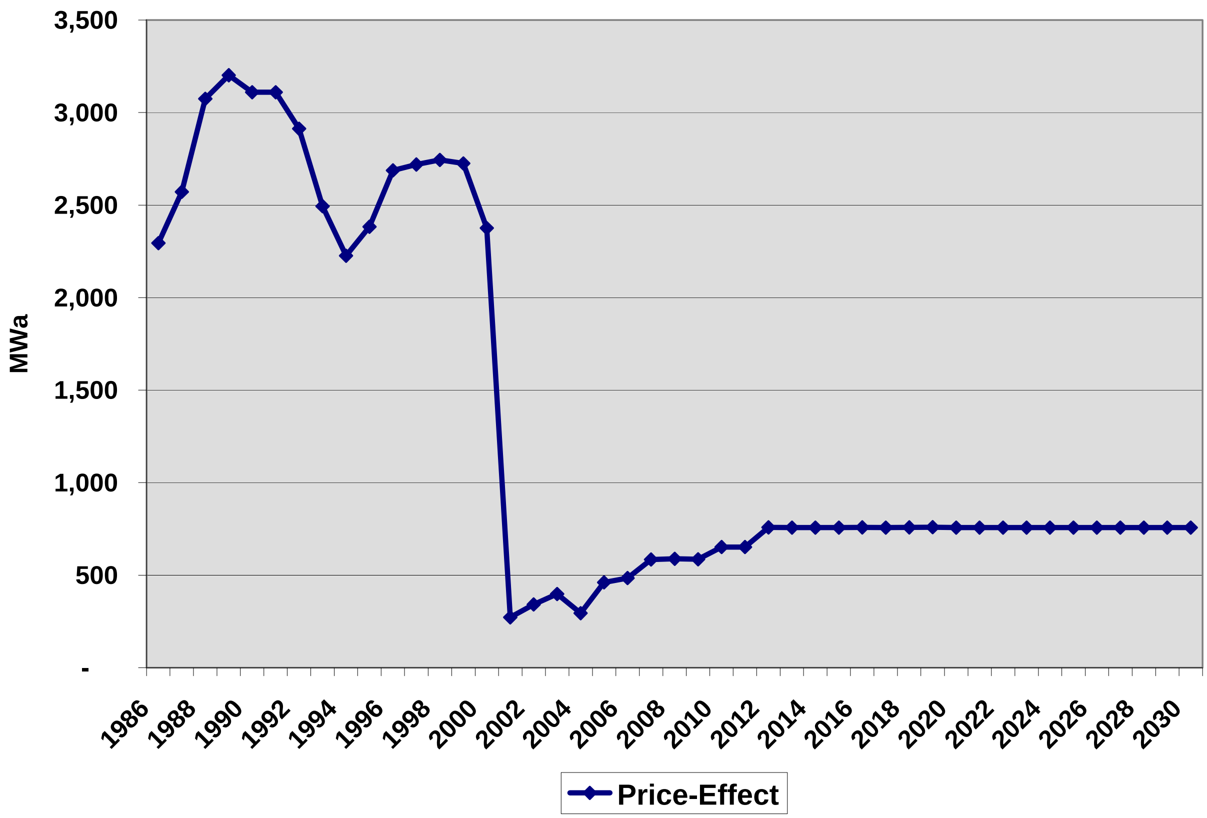



## Aluminum (DSIs)

Historically, direct service industries (DSIs) have been industrial plants that purchased their electricity directly from the Bonneville Power Administration. They have played an integral role in the development of the region's hydroelectric system, for this industrial sector grew as the region's hydroelectric system grew. The vast majority of companies in this category are aluminum smelters. When all of the region's 10 aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. However, after the power crisis of 2000-2001, many smelters shut down permanently. Currently, only a few pot lines operate in the region, consuming about 750 megawatts of power. In the Fifth Power Plan, the Council developed models to forecast electricity consumption by DSI customers. In the Sixth

Power Plan, a simplified forecast assumes that DSI consumption will be around 600-700 average megawatts for the forecast period. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-BPA sources is not technically a DSI (it is not served by BPA), that load is included in the DSI category for convenience in the Sixth Power Plan.

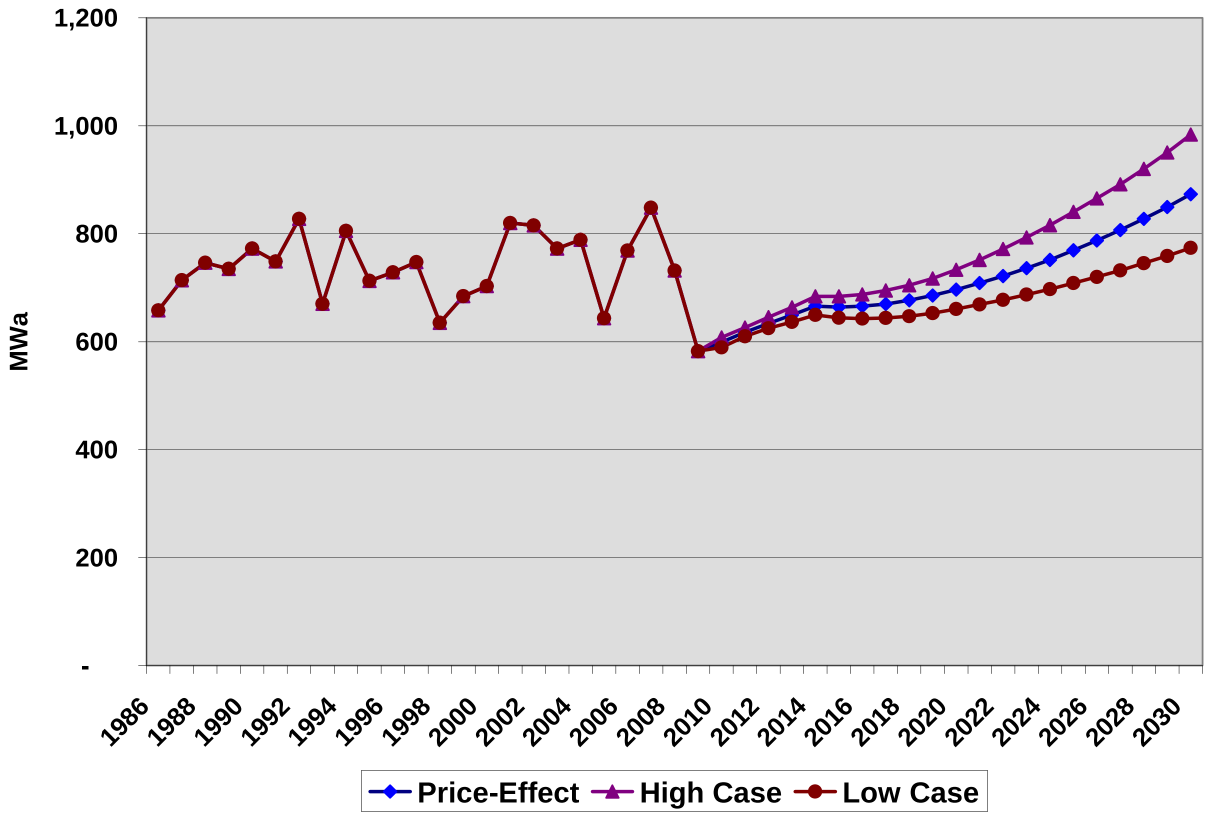
**Figure C-11:  Forecast DSI Electricity Sales**




## Irrigation

Regional irrigation load is relatively small compared to the residential, commercial, and industrial sectors.  Irrigation averaged about 740 average megawatts per year between 1986 and 2007 with little trend development discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations.  The electricity consumption in this sector is forecast to grow at 1.9 percent annually for the forecast period, above its historic 1986-2007 growth rate. The main factor influencing demand for irrigation is precipitation.  The main economic driver for this sector is the demand for agricultural products requiring irrigation.  Agricultural output is forecast to grow at an average annual rate of 3-4 percent in the 2010-2030 period.  Demand for electricity for food product manufacturing (fruits, meats, and dairy) is included in the industrial sector forecast.

**Figure C-12: Irrigation Class, Electricity Sales**




The historic growth rate for the years 1986-2007 was about 1.2 percent per year. If projected increases in summer temperatures are realized, the need for irrigation to support agricultural crops could increase.

Regional data on irrigation load has been difficult to obtain. An action item for the Sixth Power Plan might be to establish a reporting mechanism to the Council so that irrigation loads can be followed more frequently and accurately.

### Transportation Demand

The use of electricity in the transportation sector, consisting mainly of mass transit systems in major metropolitan cities in the region, typically has been estimated to be about 60 average megawatts. The forecast growth rate for transportation sector is about 2.3 percent per year. The plug-in electric vehicle could be a growing segment of this sector. The Council's preliminary analysis indicates that demand from plug-in electric vehicles could add 100-550 average megawatts to regional electricity use. In the sensitivity section of the Sixth Power Plan, the effect of plug-in electric vehicles is included in the analysis.

## *Demand History and Forecast by State*

In the past, the Council's demand forecast was available at the regional level. In the Sixth Power Plan, state-level forecasts are also available. A brief review of the historic growth rate and forecast growth rate for each state is presented in the following graph and table. Demand has been growing faster in Oregon and Idaho compared to Washington and Montana. The 2000-

2001 energy crisis and the closure of DSIs in Washington, Montana, and Oregon caused a substantial drop in industrial load. Residential demand for electricity has been growing at an average annual rate of 1.4-2.2 percent per year. Commercial demand has been growing at 0.4-2.2 percent per year. Industrial demand has had a negative growth rate in all states except Idaho. Idaho industrial load has been growing at 2.7 percent per year in the 1986-2007 period.

**Figure C-13: Historic and Forecast Demand for Electricity (MWa)**

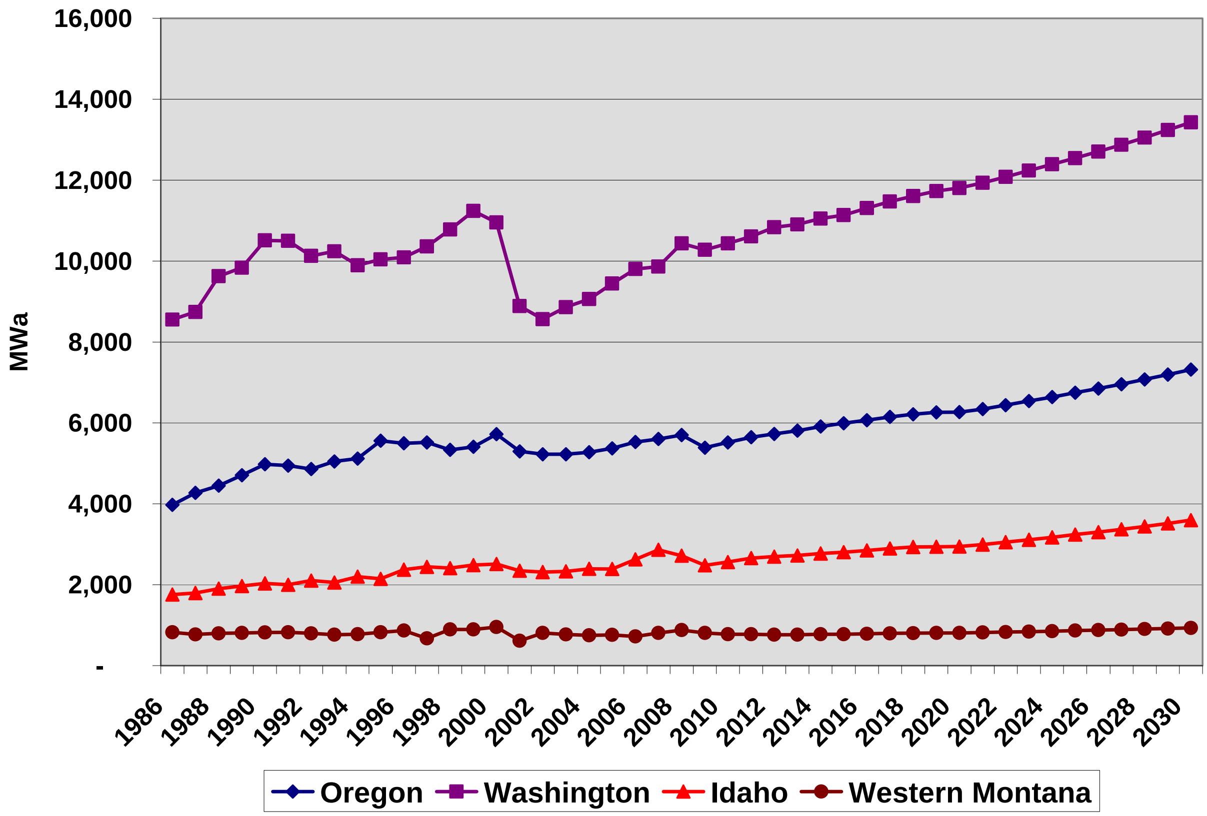



**Table C-5: Average Annual Growth Rate[1] in Demand for Electricity**

| | Oregon | Washington | Idaho | Western Montana | Region |
|---|---|---|---|---|---|
| **1986-2007** | 1.64% | 0.63% | 2.32% | -0.73% | 1.07% |
| **2010-2020** | 1.56% | 1.46% | 1.46% | 1.48% | 1.49% |
| **2010-2030** | 1.24% | 1.17% | 1.59% | 1.28% | 1.26% |

## *Monthly Pattern of Demand*

Demand is not evenly distributed throughout the year. In the Northwest, demand for electricity is higher in the winter and summer and lower in spring and fall. The historic demand for electricity for the region shows a “W”-shaped profile. Approximately 9-10 percent of annual electricity in the region is consumed in the winter months of January and December. In the

[1] Caution is warranted when interpreting the average annual growth rate. The average annual growth rate is sensitive to medium year values. Additional information on annual demand for each state is available in the companion Excel worksheet available on the Council’s website, and will provide a more accurate picture of historic and future growth.

shoulder months (March through June, and September through November) monthly energy consumption is about 8 percent. In summer months, it is slightly above 8 percent. Similar patterns can be observed in each one of the four states, with electricity demand in Idaho slightly higher in summer and slightly lower than the regional average in winter months.

**Figure C-14: Monthly Pattern of Demand for Electricity**

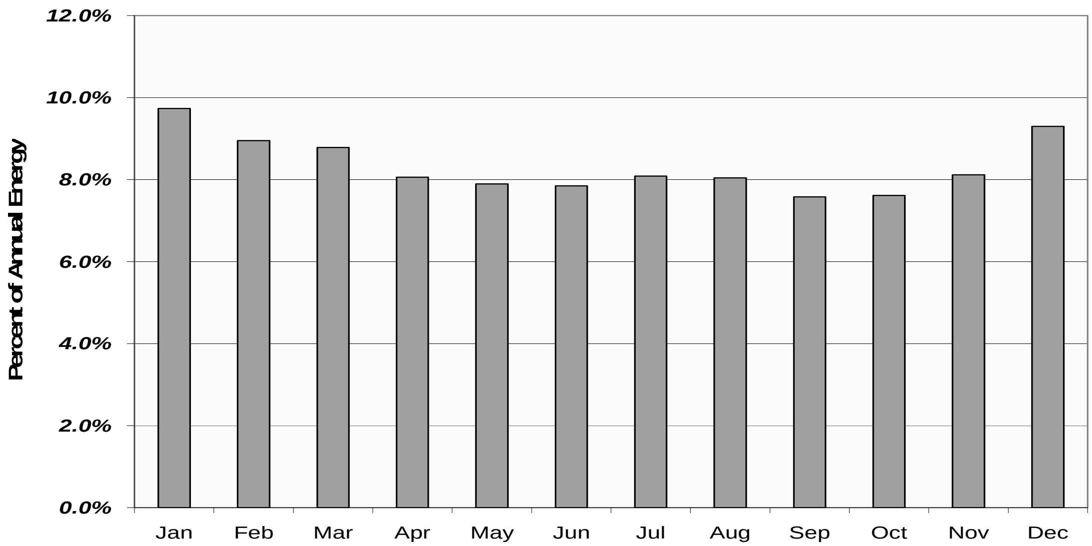



**Table C-6: Monthly Pattern of Demand for Electricity**

| | ID | MT | OR | WA | Region |
|---|---|---|---|---|---|
| **Dec** | 9% | 9% | 9% | 9% | 9% |
| **January** | 9% | 10% | 10% | 10% | 10% |
| | | | | | |
| **July** | 10% | 8% | 8% | 8% | 8% |
| **Aug** | 9% | 8% | 8% | 8% | 8% |

In order to make sure there are sufficient resources available to meet demand, it is necessary to forecast the timing of peak load.

# REGIONAL PEAK LOAD

As discussed in Appendix B of the Sixth Power Plan, the temporal pattern of demand and its peaks are becoming more important. The region was once constrained by average annual energy supplies. Today, the region is more likely to be constrained by sustained-peaking capability.

To better forecast the temporal pattern of demand and hourly load, the Council has developed two sets of models:

- A short-term load forecasting model that projects 3-5 years into the future on an hourly basis. The short-term model is used for the resource adequacy analysis.

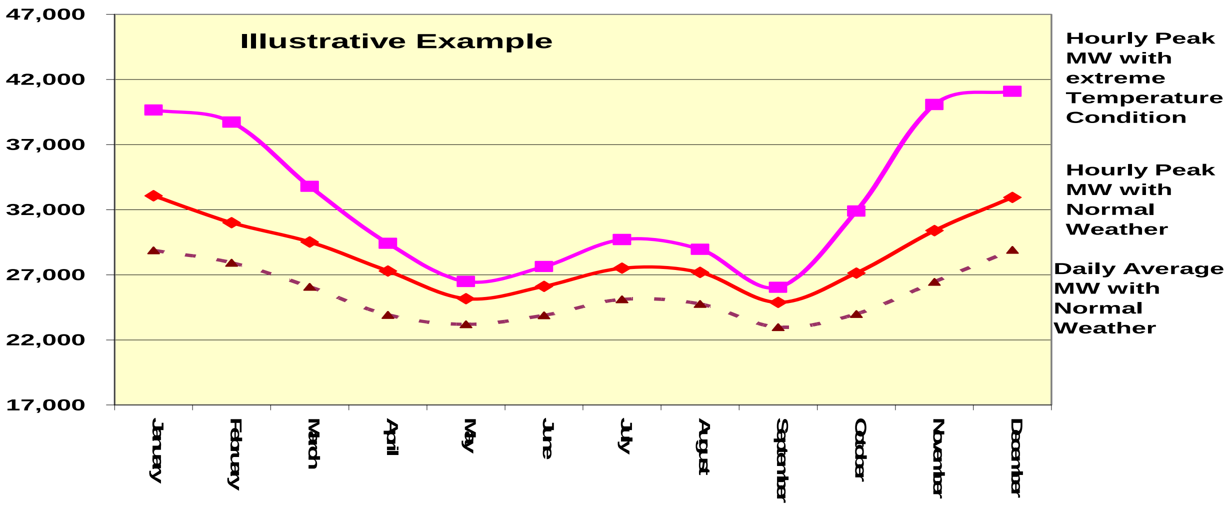
- A long-term load forecasting model that projects 20 years into the future on a monthly basis.

This appendix discusses the long-term forecasting model.

## *Seasonal Variation in Load*

Regional load has significant seasonal variability driven by temperature changes.  Although the Northwest is a winter-peaking region, there can be a significant range in winter load.  Illustrating this, the following graph measures three examples of load.  The dashed line shows the daily average megawatts of energy under normal weather conditions.  Winter daily energy demand is about 28,000 megawatts, and summer average demand is about 24,000 megawatts. With normal weather, the peak-hour load in winter reaches over 33,000 megawatts, and the summer peak increases to about 28,000 megawatts.  If weather conditions are extreme, then the hourly load can increase substantially and has reached more than 41,000 in winter and more than 30,000 in the summer.

**Figure C-15:  Range of Variation in Load**




### Demand versus Load

The demand forecast figures presented earlier were for customer demand and did not include transmission and distribution losses.  This energy loss from transmission and distribution varies depending on temperature conditions and the mix of sectors.  Higher temperatures mean a greater loss of energy.  Transmission and distribution losses also increase as the regional load shifts to the residential or commercial sector.  Large industrial customers like the DSIs typically have lower losses because they can receive power at the transmission level.  The following table shows the projected annual load and sales for the region.

**Table C-7: Annual Demand and Loads (MWa)**

| | Annual Demand | Annual Load | | Annual Demand | Annual Load |
|---|---|---|---|---|---|
| **2009** | 18,959 | 21,369 | 2020 | 21,820 | 24,593 |
| **2010** | 19,292 | 21,745 | 2021 | 22,083 | 24,890 |
| **2011** | 19,691 | 22,194 | 2022 | 22,399 | 25,246 |
| **2012** | 20,021 | 22,566 | 2023 | 22,729 | 25,618 |
| **2013** | 20,205 | 22,774 | 2024 | 23,059 | 25,990 |
| **2014** | 20,509 | 23,116 | 2025 | 23,400 | 26,374 |
| **2015** | 20,713 | 23,346 | 2026 | 23,736 | 26,753 |
| **2016** | 21,005 | 23,675 | 2027 | 24,091 | 27,153 |
| **2017** | 21,307 | 24,015 | 2028 | 24,472 | 27,582 |
| **2018** | 21,552 | 24,292 | 2029 | 24,868 | 28,028 |
| **2019** | 21,736 | 24,499 | 2030 | 25,275 | 28,488 |

## *Resource Adequacy and Peak Forecast*

To make sure adequate resources are available to meet load under the range of variations shown in Table C-7, regional resource adequacy guidelines have been established. These guidelines do not focus on peak load for a single hour, but rather use the concept of a sustained-peak period (SPP). The sustained-peak period is defined as an 18-hour period over three consecutive days. The sustained-peak load for adequacy assessment is determined in the short-term forecasting model. A discussion on the development and application of short-term can be found in the Resource Adequacy Forum, February 5, 2007 Technical Committee Meeting.[2]

## *Peak Load Forecast Methodology (Long-term Model)*

One approach to forecasting temporal demand is to use historical monthly and hourly patterns. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate future hourly demand patterns. The methodology used in the Sixth Power Plan is similar to the Fourth Power Plan approach, in which the detailed hourly demand for numerous end-uses and sectors built the model's load profile.

In the Sixth Power Plan, monthly demand patterns for specific end-uses were used to create a cumulative regional load forecast. Hourly load profiles for each end-use were mapped against the system load profile and an end-use specific load shape factor (LSF) was calculated. This tells us which end-use is contributing to the peak and by how much. The calculation for LSF is done on a monthly basis. This method allows the Council's model to make specific forecasts for end-uses that are increasing like air conditioning or ICE technologies.

The load shape factors currently used by the Council were gathered from the best available data, but they should be updated. An action item for the Sixth Power Plan is to update the load shape for various end-uses.

[2] http://www.nwcouncil.org/energy/resource/meetings/2007/02/20507%20Tech%20Short%20Term%20Loads.pdf

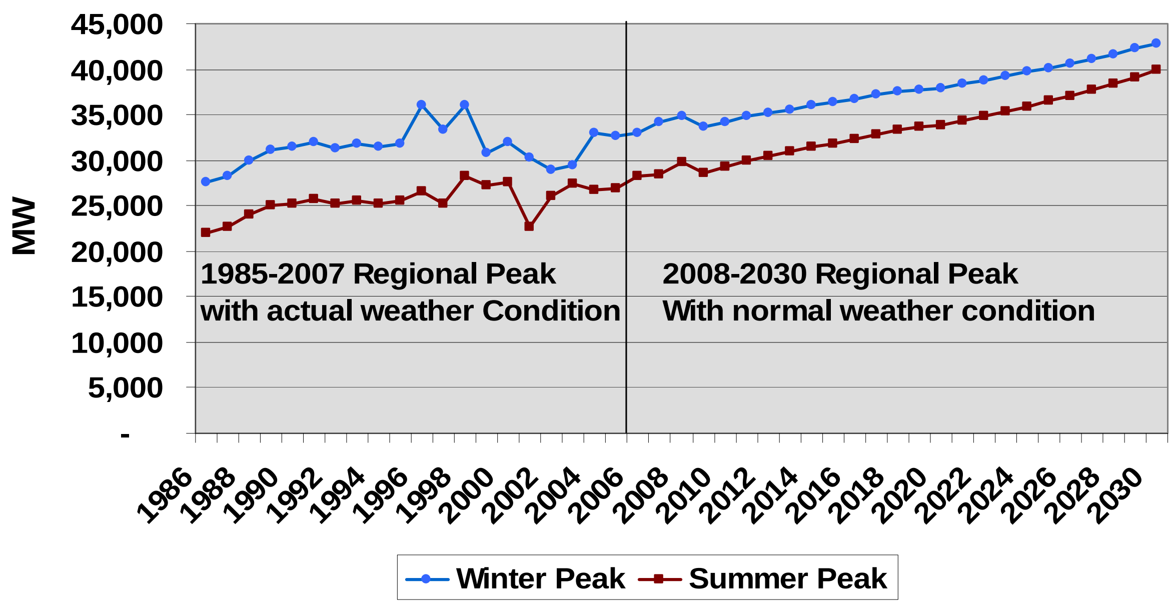
## *Regional Peak Load Forecasts*

The regional peak load is expected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030 at an average annual growth rate of 1.1 percent. With no climate change scenarios, the region is expected to remain winter peaking until near the end of the planning horizon. Figure C-16 shows the forecast peak load for winter and summer months under different scenarios. Note that the estimated peak load for 2007 reflects the actual peak temperatures for 2007. However, the peak load forecasts for 2010, 2020, and 2030 are based on normal weather conditions. The forecast of peak load suggests that the region's winter and summer peak loads become close by the end of forecast period, about 3,000 MW apart. The growth rate for the summer peak is higher than the winter peak. The growth rate for the winter peak is 1.1 percent per year compared to the summer peak growth rate of 1.6 percent.

**Table C-8: Total Summer and Winter Peak Load Forecasts MW**

| | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Medium - Winter** | 33,908 | 34,184 | 37,977 | 42,814 | 1.06% | 1.13% |
| **Medium - Summer** | 28,084 | 29,211 | 33,800 | 39,865 | 1.47% | 1.57% |

**Figure C-16: Peak Load Demand for Electricity (MW)**




The growth rate of summer and winter peak load depends on the growth rate of the economy in general. In the high-growth scenario, the summer peak grows at 1.9 percent per year. In the low-growth scenario, the summer peak grows at 1.1 percent per year. The winter peak load in the region could increase from about 34,000 megawatts in 2007 to about 46,000 megawatts in 2030. The summer peak load is forecast to grow at a faster rate, 1.1-1.9 percent per year, increasing from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030.

**Table C-9: Total Summer and Winter Peak Load Forecasts MW**

| | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Low - Winter** | 33,908 | 33,572 | 35,412 | 36,949 | 0.5% | 0.5% |
| **Low - Summer** | 28,084 | 28,517 | 32,027 | 35,559 | 1.2% | 1.1% |
| **Medium - Winter** | 33,908 | 34,184 | 37,977 | 42,814 | 1.1% | 1.1% |
| **Medium - Summer** | 28,084 | 29,211 | 33,800 | 39,865 | 1.5% | 1.6% |
| **High - Winter** | 33,908 | 34,611 | 39,397 | 46,788 | 1.3% | 1.5% |
| **High - Summer** | 28,084 | 29,706 | 34,923 | 43,360 | 1.6% | 1.9% |

## Residential Sector

Peak load for the residential sector during the winter season is estimated to increase from about 19,700 megawatts in 2007 to about 24,000 megawatts by 2030, an annual growth rate of about 0.8 percent per year. This growth rate is slower than forecast growth rate for energy demand in the residential sector. During the summer peak, high demand by the residential sector is anticipated to increase by 1.6-2.9 percent per year, depending on the economic growth scenario.

**Table C-10: Residential Summer and Winter Peak Load Forecasts MW**

| Residential | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Low - January** | 19,701 | 19,373 | 19,175 | 19,505 | -0.1% | 0.2% |
| **Low - July** | 8,101 | 8,422 | 9,173 | 10,791 | 0.9% | 1.6% |
| **Price-effect - January** | 19,701 | 19,538 | 21,070 | 23,687 | 0.8% | 1.2% |
| **Price-effect - July** | 8,101 | 8,477 | 9,865 | 12,513 | 1.5% | 2.4% |
| **High - January** | 19,701 | 19,637 | 22,090 | 26,184 | 1.2% | 1.7% |
| **High - July** | 8,101 | 8,510 | 10,257 | 13,612 | 1.9% | 2.9% |

## Commercial Sector

Peak load for the commercial sector during the winter season is estimated to increase from about 6,200 megawatts in 2007 to about 9300 megawatts by 2030, an annual growth rate of 1.8 percent per year. The summer season peak loads in this sector are projected to grow from 10,250 megawatts in 2007 to about 16,000 megawatts in 2030, or about 2.0 percent per year. This growth rate is higher than the growth rate in the annual energy use forecast for this sector.

**Table C-11: Commercial Summer and Winter Peak Load Forecasts MW**

| Commercial | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Low - January** | 6,230 | 6,630 | 7,831 | 8,444 | 1.7% | 0.8% |
| **Low - July** | 10,250 | 10,971 | 13,351 | 14,756 | 2.0% | 1.0% |
| **Price-Effect- January** | 6,230 | 6,809 | 8,298 | 9,274 | 2.0% | 1.1% |
| **Price-Effect- July** | 10,250 | 11,264 | 13,940 | 15,678 | 2.2% | 1.2% |
| **High - January** | 6,230 | 6,987 | 8,572 | 9,982 | 2.1% | 1.5% |
| **High - July** | 10,250 | 11,554 | 14,182 | 16,399 | 2.1% | 1.5% |

## Industrial Sector

The load profile of the industrial sector is typically flat, with little hourly or seasonal variation. In the winter, the estimated industrial sector contribution to the electricity system’s peak is anticipated to be about 5,760 megawatts in 2007, increasing to about 6,300 megawatts by 2030. During the summer season, the industry's contribution to the region's peak use is slightly greater than its contribution to winter peak demand because the regional summer peak usually occurs during mid-day working hours, whereas the system winter peak occurs during either early morning or early evening.

**Table C-12: Industrial Summer and Winter Peak Load Forecasts MW**

| Industrial (net of irrigation) | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| Low - January | 5,760 | 5,120 | 5,093 | 5,128 | -0.1% | 0.1% |
| Low - July | 6,177 | 5,601 | 5,629 | 5,655 | 0.1% | 0.0% |
| Price-Effect- January | 5,760 | 5,380 | 5,481 | 6,301 | 0.2% | 1.4% |
| Price-Effect- July | 6,177 | 5,867 | 6,036 | 6,892 | 0.3% | 1.3% |
| High - January | 5,760 | 5,120 | 5,093 | 5,128 | -0.1% | 0.1% |
| High - July | 6,177 | 5,537 | 5,381 | 4,941 | -0.3% | -0.8% |

## Irrigation Sector

Agricultural crops are not irrigated in the winter, so the irrigation sector does not contribute to the winter system peak. However, this sector can contribute significantly to the system peak in the summer. The estimated contribution of the irrigation sector to the 2007 summer peak was about 2,900 megawatts. Peak-load demand is projected to grow to about 3,000 megawatts by 2030.

**Table C-13: Irrigation Summer and Winter Peak Load Forecasts MW**

| Irrigation | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| Low - January | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| Low - July | 2,879 | 2,010 | 2,252 | 2,633 | 1.1% | 1.6% |
| Price-Effect- January | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| Price-Effect- July | 2,879 | 2,043 | 2,375 | 2,971 | 1.5% | 2.3% |
| High - January | 0 | 0 | 0 | 0 | 0.0% | 0.0% |
| High - July | 2,879 | 2,074 | 2,501 | 3,347 | 1.9% | 3.0% |

## Street Lighting and Public Facilities

This sector consists of street lighting, traffic lights, and water and sewer facilities. The energy forecast for this sector is typically combined with the commercial sector demand. In 2007, this sector contributed an estimated 838 megawatts to the summer peak and by 2030, this sector's share of summer peak is projected to grow to about 1,100 megawatts. This sector is projected to grow at about 1.0 percent per year between 2010 and 2030.

**Table C-14: Irrigation Summer and Winter Peak Load Forecasts MW**

| Public Facilities & Street Lighting | 2007 | 2010 | 2020 | 2030 | Growth Rate 2010-2020 | Growth Rate 2010-2030 |
|---|---|---|---|---|---|---|
| **Low - January** | 741 | 774 | 869 | 958 | 1.2% | 0.99% |
| **Low - July** | 838 | 874 | 979 | 1,079 | 1.1% | 0.97% |
| **Price-Effect- January** | 741 | 774 | 869 | 958 | 1.2% | 0.99% |
| **Price-Effect- July** | 838 | 874 | 979 | 1,079 | 1.1% | 0.97% |
| **High - January** | 741 | 774 | 869 | 958 | 1.2% | 0.99% |
| **High - July** | 838 | 874 | 979 | 1,079 | 1.1% | 0.97% |

## *Calculations for Alternative Load Forecast Concepts*

In Chapter 3 of the Sixth Power Plan, under the heading "Alternative Load Forecast Concepts", the three different but related load forecasts are produced for use in the Council's resource planning process are discussed. In this section, we will discuss how the conservation targets were netted out of the price-effect forecast to produce the "sales"[3] forecast load. A "sales" forecast, represents the actual expected sales of electricity after all cost-effective conservation has been achieved. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the Resource Portfolio Model. The sales forecast captures both price-effects and take-back effects (due to increased usage as efficiency of usage increase).

To calculate the Sales forecast, we start with taking the conservation resource bundles (lost-opportunity and discretionary), and unbundle them into their sector and end-use specific constituents for each year. The sector and end-use specific estimates of the annual conservation targets were then netted out of the frozen-efficiency load forecast to estimate the "sales" forecast. Whenever possible, the conservation target for a given sector and end-use was netted out of the appropriate sector and end-use. However, conservation targets are estimated at a greater level of resolution than the long-term modeling tool's end-uses. So, in some cases multiple conservation targets were netted out of same end-use and sector. For example, the conservation targets for commercial lighting consist of savings due to improved lighting power density as well as better controls for interior and exterior lighting. In modeling the impact of these conservation measures, we could only modify the lighting in the commercial sector without distinguishing the nature of the lighting measure, whether it was controls or reduced power density. To properly reflect the impact of conservation measures on the energy and peak loads, a more detailed treatment of conservation savings would have been needed. In this analysis we have made a simplifying and conservative assumption that conservation measure load shapes are identical to the end-use load shapes.

The following table shows the cumulative conservation target for 2029, as well as the mapping between conservation measures and end-use in the long-term model that was modified to incorporate impact of conservation savings on load.

[3] "Sales" forecast as well as price-effect and frozen efficiency can be measured at consumer site or at generator site (which will include T&D losses). When the reference is to "demand" it is measured at customer site, and when the reference is to "load" it is measured at generator site.

Table C-15: Modeling Impact of Conservation Targets

| Sector | Conservation Measures | Calendar year 2029 MWa (at generator site) | Long-term Demand Forecast Model End-use |
|---|---|---|---|
| **Residential** | Heat Pump Water Heater | 492 | Water Heating |
| | Television and Set Top Box | 469 | Entertainment Center |
| | Computers and Monitors | 358 | Entertainment Center |
| | Heat Pump Conversions | 418 | Water Heating |
| | Clothes Washer | 108 | Clothes Washer |
| | Dishwasher | 16 | Dishwasher |
| | Refrigerator | 41 | Refrigeration |
| | Freezer | 15 | Freezer |
| | New Construction Shell | 170 | Space Heating and Cooling |
| | Heat Pump Upgrades | 97 | Space Heating and Cooling |
| | Weatherization | 284 | Space Heating and Cooling |
| | Ductless Heat Pump | 210 | Space Heating and Cooling |
| | Lighting | 249 | Lighting |
| | Showerheads | 35 | Water Heating |
| | **Total** | **3148** | |
| | | | |
| **Commercial** | Lighting Power Density (lost Op) | 340 | Lighting |
| | Lighting Power Density (discretionary) | 30 | Lighting |
| | Interior Lighting Controls (lost Op) | 90 | Lighting |
| | Exterior Lighting (lost Op) | 190 | Lighting |
| | Integrated Building Design | 60 | Space Conditioning |
| | Packaged Refrigeration Equipment | 50 | Refrigeration |
| | Controls Commission Complex HVAC | 110 | Space Conditioning |
| | Controls Optimization Simple HVAC | 30 | Space Conditioning |
| | Grocery Refrigeration Bundle | 90 | Refrigeration |
| | Computer Servers and IT | 130 | Misc. Plug-in electric |
| | Network PC Power Management | 70 | Misc. Plug-in electric |
| | Other Commercial Measures | 20 | Misc. Plug-in electric |
| | **Total** | **1370** | |
| | | | |
| **Industrial** | All industrial Measures | 760 | Spread over all endues and industries |
| **Irrigation** | All Irrigation Measures | 100 | Motors |
| **Public Facilities** | Municipal Sewage Treatment & Water Supply | 50 | Motors |
| **All Sectors** | Distribution Efficiency Measures | 400 | Spread over all sectors And end-uses |

# ELECTRICITY DEMAND GROWTH IN THE WEST

Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORAxmp electricity market model requires energy and peak load forecasts for 16 areas. Four of these areas make up the Pacific Northwest -- forecasts for these areas come from the Council's demand forecast model. Forecasts for the remaining 12 areas come from the Transmission Expansion Planning Policy Committee (TEPPC), which is part of the Western Electricity Coordinating Council (WECC).

For the two California areas, Council staff used forecasts submitted by the California Energy Commission from 2008-2020. For the remaining 10 areas (not in California and not in the Pacific Northwest) Council staff used forecasts from TEPPC for 2012-2018. For the period 2008-2011 these 10 areas' demand for electricity was interpolated between historic levels in 2008 and forecast levels in 2012, with a 4 percent reduction in 2009 and 2010 to reflect the current recession. AURORA requires area load projections for each year to 2053, so Council staff extended the forecasts past 2020 (for California) and 2018 (for the other 10 areas) by calculating a rolling average for the past five years.

**Table C-16: Naming Convention for Aurora Areas**

| Area Name | Short Area Name |
|---|---|
| Pacific NW Eastside | PNWE |
| California North | CAN |
| California South | CAS |
| British Columbia | BC |
| Idaho South | IDS |
| Montana East | MTE |
| Wyoming | WY |
| Colorado | CO |
| New Mexico | NM |
| Arizona | AZ |
| Utah | UT |
| Nevada North | NVN |
| Alberta | AB |
| Mexico Baja CA North | BajaN |
| Nevada South | NVS |
| Pacific NW Westside | PNWW |

AURORA's model information covers a large and diverse area. Figure C-17 shows the 2010 projected demand for energy.

**Figure C-17: 2010 Projected Electricity Load by AURORA Area (MWa)**

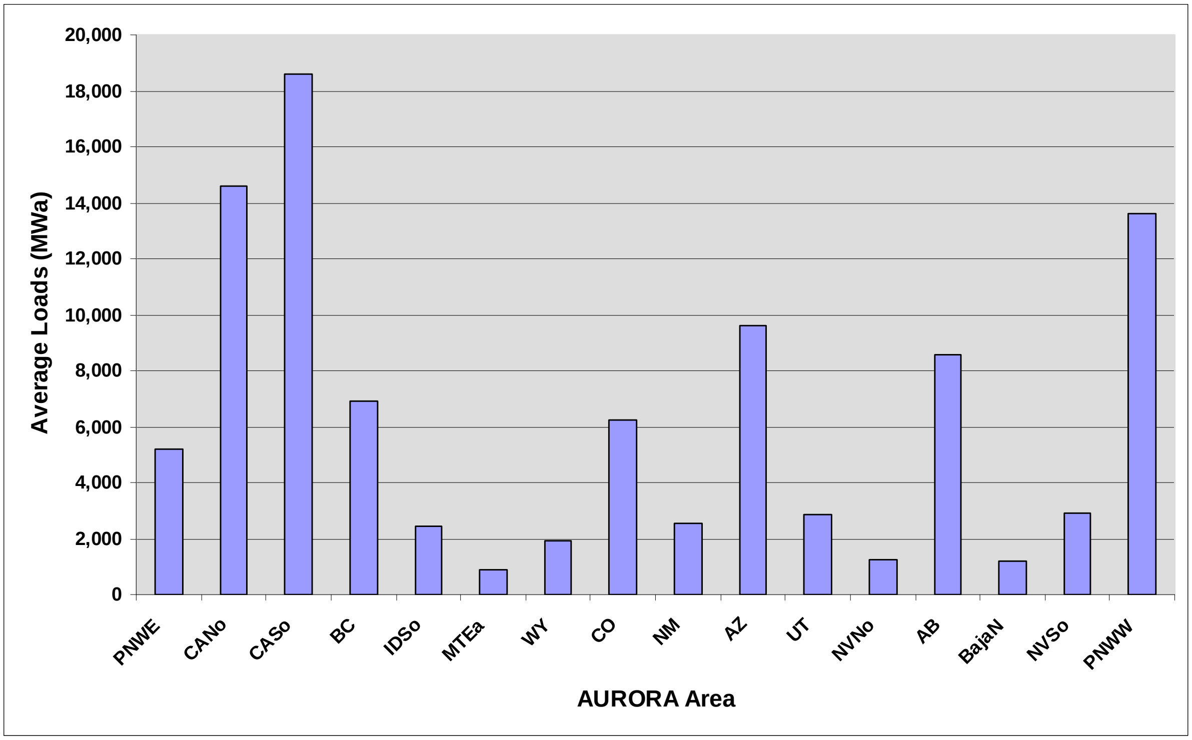



Figure C-18 shows the 2010-2030 projected growth rates for demand in the 16 geographic areas. The figure shows the projected growth rates for areas that are expected to experience demand increases of less than 1 percent and areas that are forecast to experience demand increases of nearly 4 percent. The highest projected rates of change are the geographic areas of Alberta, Canada, and Arizona, followed by Wyoming, Utah and southern Nevada. The lowest rates are for PNW Eastside, British Columbia, Eastern Montana and PNW Westside, all anticipated to grow at less than 0.5 percent by 2027. The four Pacific Northwest areas have projected load growth rates at the lower end of the range of the WECC area, at about 0.4 percent by 2030.[4] These areas include: the eastern portions of Oregon and Washington, the northern part of Idaho (PNWE), southern Idaho (IDS), eastern Montana (MTEa), and the western portions of Oregon and Washington (PNWW).

[4] All forecasts are net of planned conservation, which reduces the forecasts quite substantially in the Pacific Northwest and several other areas.

**Figure C-18: Percent Annual Growth 2010-2030 by AURORA Area (MWa)**

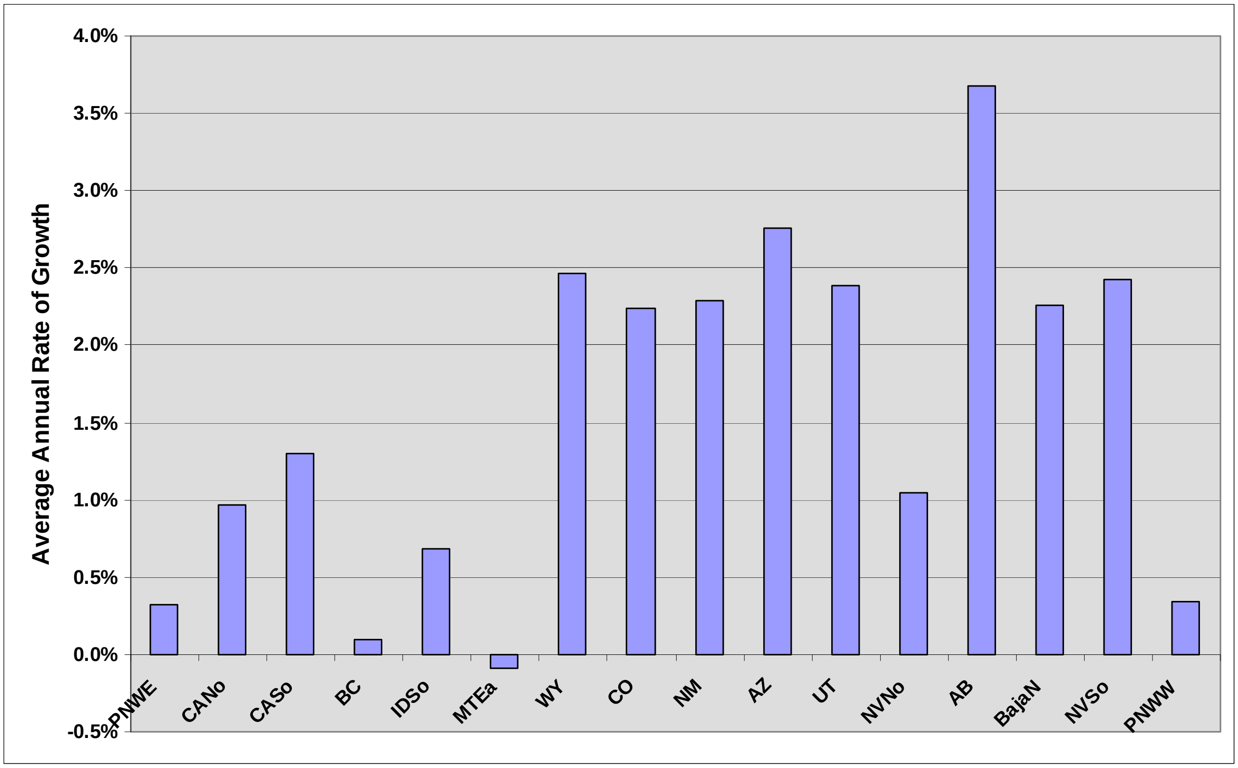



**Figure C-19: 2010 Projected Peak Load by AURORA Area (MW)**

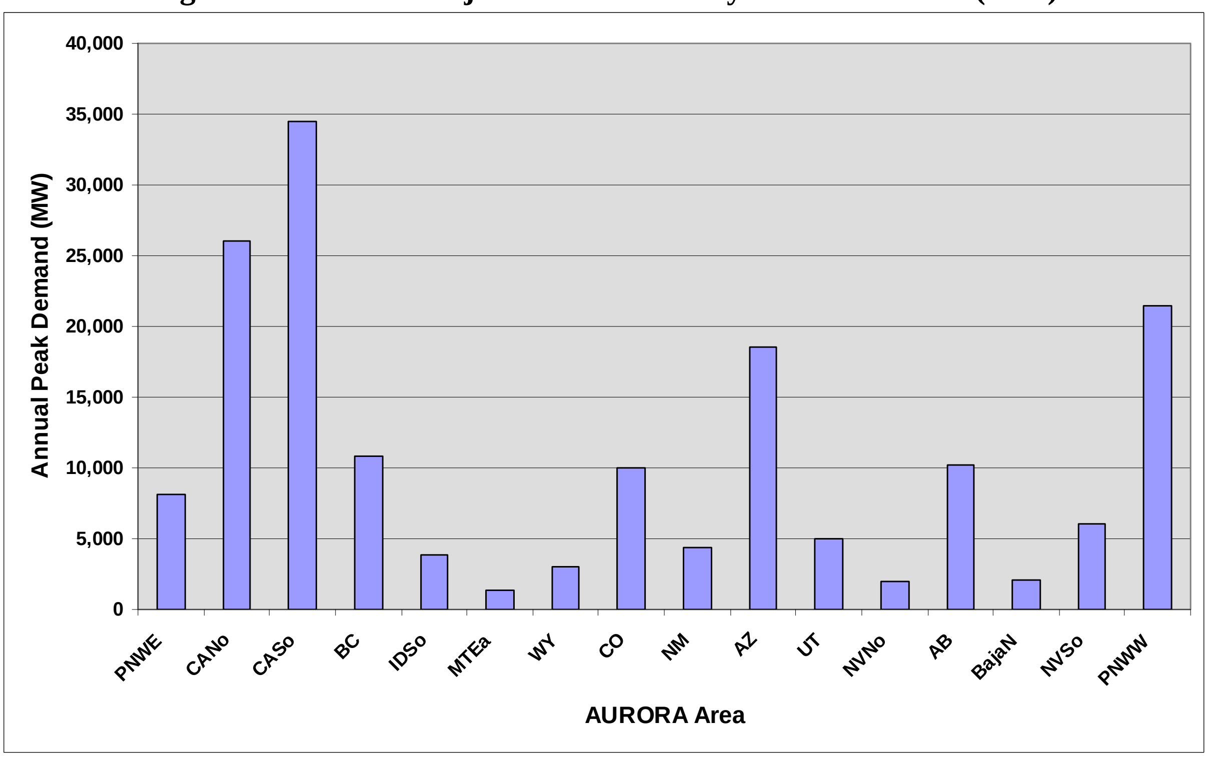


Figure C-19 shows the 2010 projected peak load by AURORA area. The figure demonstrates a wide range in projections of peak demand among geographic areas. It is important to note that these projections are non-coincident (individual utility) peaks, and while six of the areas (PNWE, BC, MTEa, WY, AB, and PNWW, totaling about 55,000 megawatts) are winter peaking, the rest of WECC, totaling about 102,000 megawatts, are summer-peaking areas. The WECC area as a whole is summer peaking.

# SPECIAL TOPICS

This section describes the impact of custom data centers and plug-in hybrid electric vehicles (PHEV) on demand. The effect of PHEV on demand is treated as a sensitivity analysis in Chapter 3.

## *Estimating Electricity Demand in Data Centers*

### Background on Trends in Data Center Load

A brand new load type has emerged recently, starting in 2000. Large data centers have been attracted to the Northwest because of its low electricity prices and moderate climate, meaning fewer storms and power interruptions.

#### *What is a Data Center?*

"Data center" is a generic term used to describe a number of different types of facilities that house digital electronic equipment for Internet-site hosting, electronic storage and transfer, credit card and financial transaction processing, telecommunications, and other activities that support the growing electronic information-based economy.[5] In general, data centers can be categorized into these two main categories:

- Custom data centers, such as Google, Yahoo, and Microsoft sites in the Grant County PUD and Northern Wasco County PUD. These data centers are typically very large, consisting of thousands of servers and representing a significant demand for power. They are usually sited close to transmission facilities and are typically charged industrial retail rates by their local utility.

- Hidden data centers, like those in business offices, may include a small separate office or closet with a few servers, or larger server facilities with hundreds of servers. These data centers are called “hidden data centers” because they are part of existing commercial businesses. They are usually in urban settings and are typically charged commercial retail electric rates by their local utility.

Tracking load from data centers (especially custom data centers) is important because their growth rate has been swift, and their size generally creates a large demand. The Council currently estimates that the region has about 300 average megawatts of connected load used by custom data centers, and another 300 average megawatts of load that can be attributed to hidden

[5] http://www.gulfcoastchp.org/Markets/Commercial/DataCenters

data centers. If national projected trends for non-custom servers holds true, the load from these data centers can increase by 50 percent by the year 2011.

**National Picture:** Research conducted nationally for the EPA[6] in 2005 shows that electricity sales for servers and data centers was about 6,200 average megawatts or about 1.5 percent of total U.S. retail electricity sales. This estimated level of electricity consumption is more than the electricity consumed by the nation's color televisions, and is similar to the amount of electricity consumed by approximately 5.8 million average U.S. households (or about 5 percent of the total U.S. housing stock). The energy use of the nation's servers and data centers in 2006 is estimated to be more than double the electricity consumed for this purpose in 2000. The power and cooling infrastructure that supports IT equipment in data centers also uses significant energy, and accounts for 50 percent of the total electricity consumption of these centers. Among the different types of data centers, the nation's largest (enterprise-class facilities used by the banking industry or the airline industry) and most rapidly growing data centers use more than one-third (38 percent) of the electricity from this sector.

This total does not yet include the load of larger custom server sites. No detailed estimates for load from these types of data centers exist. However, Lawrence Berkeley Labs conservatively estimates the demand of these sites to be about 900 average megawatts nationally. In total, 1.7 percent of national retail electric sales can be attributed to servers and data centers.

**Regional Picture:** To estimate the total load for servers and data centers in the region, the Council assumed that the region's demand from these sites is similar to the nation's demand. To verify this assumption, the percent of each state's gross state product generated by information-intensive industries (such as Internet-service providers and financial institutions) was calculated. Then, the same percentage at the national level was calculated and the two figures compared. The analysis showed that the information-intensive industries' contribution to the GSP is similar to the contribution of the same industries nationally. The region as a whole is similar to the nation in the contribution of information-intensive industries to the regional economy. The analysis showed that in the Northwest, 1.47 percent of total electricity sales, or about 285 average megawatts, can be attributed to servers and data centers.

This estimate excludes custom data centers attracted to the region by access to fiber optic networks, low electricity prices, and a moderate climate. The Council contacted utilities serving these customers for more information. Preliminary estimates put the custom data centers' consumption at about 300 average megawatts of connected load. Typically, custom data centers project their future peak power requirements and the local utility then sizes the distribution facilities to those requirements. Conversations with utilities indicate that the full load would occur over several years rather than immediately.

**Future Trends:** Nationally, electricity sales to server operations have grown suddenly and rapidly. By 2010, the number of total U.S. installed servers is expected to increase from 5.6 million in 2000 to over 15 million servers. This phenomenal sales growth highlights the impact of servers and data centers on demand. But there are also many opportunities to reduce this sector's demand. In the EPA study mentioned earlier, three different energy-efficiency scenarios were explored:

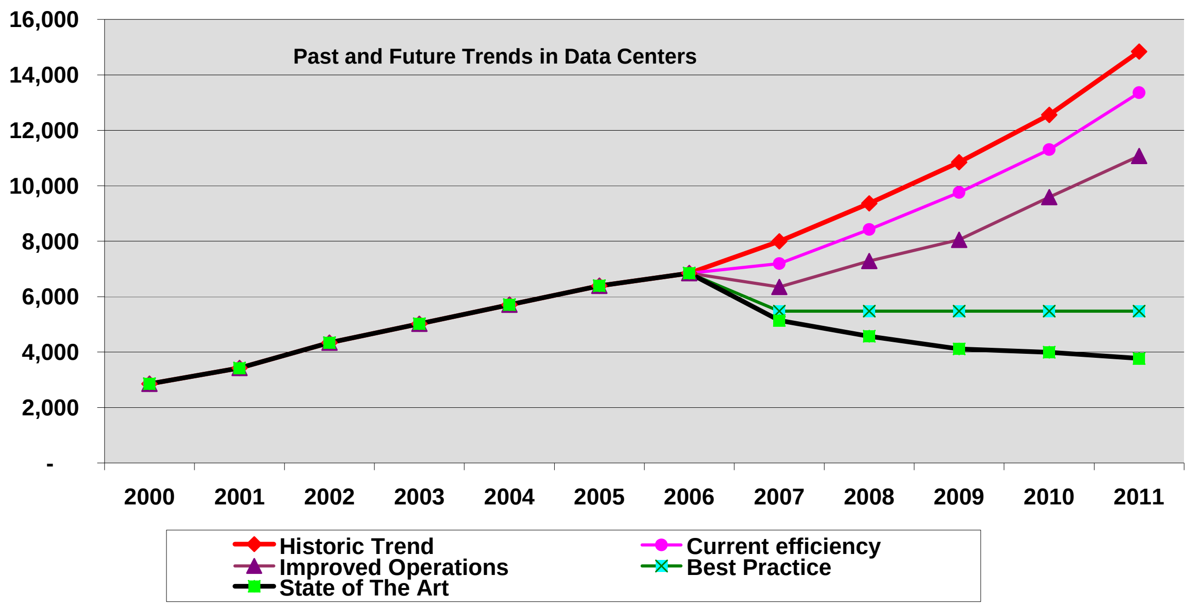
[6] Report to Congress on Server and Data Center Energy Efficiency Public Law 109-431

- The "**improved operation**" scenario includes energy-efficiency improvements beyond current efficiency trends that are essentially operational changes and require little or no capital investment. This scenario represents the "low-hanging fruit" that can be harvested simply by operating the existing capital stock more efficiently.  An example of low-hanging fruit is isolating hot and cold isles in the data center, thus reducing air-conditioning demand.  Potential savings from this category of improved energy efficiency: 30 percent.

- The "**best practice**" scenario represents the efficiency gains that can be obtained through the more widespread adoption of practices and technologies used in the most energy-efficient facilities in operation today.  Potential savings from this category of improved energy efficiency: 70 percent.

- The "**state-of-the-art**" scenario identifies the maximum energy-efficiency savings that could be achieved using available technologies. This scenario assumes that U.S. servers and data centers will be operated at the maximum possible energy efficiency using only the most efficient technologies and the best management practices available. Potential savings from this category of improved energy efficiency: 80 percent.

**Figure C-20:  National Forecast for Demand from Data Centers**




If regional trends follow national trends, load from non-custom servers will increase from its current 285 average megawatts to about 570 average megawatts.  Load for custom data centers may also double by 2010.  However, there are indications that this projected doubling may not occur.  Growth-limiting factors include technological improvements like the use of "virtualization" (using one server to do the job of many), the use of alternative storage technologies, better power management, as well as other limiting factors such as access to water for cooling needs, limitations on tax incentives, and limitations on below-market electricity rates.

**Conservation Opportunities:**  Significant conservation opportunities may be available, depending on the type of data center.  For example, installing the proper size of cooling equipment can significantly reduce consumption. Cooling technologies for server equipment may help the industry maintain, rather than increase, the cost of custom data centers. Currently, we do not have a good baseline assessment of the installed cooling equipment in hidden and custom data centers. An action item for the Sixth Power Plan is to establish such a baseline.

### *Methodology for Estimating Custom Data Center Loads*

Load for non-custom (hidden) data centers is imbedded in the commercial sector load forecast and is not separately estimated. Load for custom data centers is forecast separately using the following method:

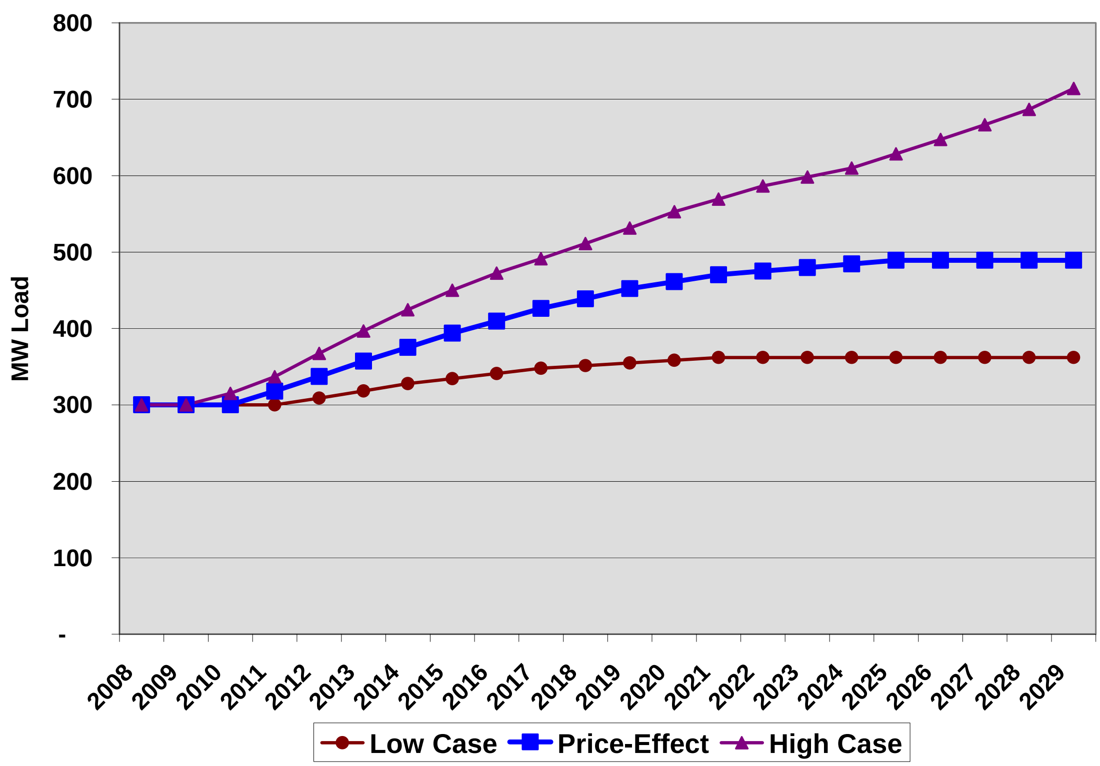
Load for this type of data center in 2008 was estimated. Two trends were then considered. The first trend reflects the increase of demand for services from this sector at a rate of 3 -10 percent per year (3 percent for a low-growth scenario, 7 percent for a medium-growth scenario, and 10 percent for a high-growth scenario). The second trend is the potential improvement in energy efficiency in data centers. Three alternative scenarios for potential improvement in energy efficiency were considered. The medium growth scenario assumed that improvements in energy efficiency start at about 1 percent per year in 2012, increasing gradually to 7 percent per year by 2026. The low-growth scenario assumed that energy-efficiency improvements would be on a slower trajectory, starting at about 1 percent in 2015, and ramping up to about 3 percent by 2022. The high-growth scenario assumed a more rapid growth path for energy-efficiency improvements, starting at 1 percent per year in 2012, increasing to 7 percent by 2020, and 10 percent by 2026. The combination of load growth factors and improvement in energy efficiency result in a flat load growth for the data centers in the later parts of the forecast period. The assumed improvements in energy efficiency presented here are market-driven and are not considered as part of the Council's conservation potential.

The year-by-year growth in demand and improvement in efficiency for the medium case scenario is shown in the following table. The following graph shows the projected load for alternative energy efficiency and load-growth scenarios. It is assumed that the current estimated connected load of 300 average megawatts would be sufficient to meet the load from custom data centers until 2012.

**Table C-17: Medium Case Trends in Data Center Loads**

| | Growth in Demand | Increase in Efficiency | Load MWa |
|---|---|---|---|
| **2008-2011** | 0% | 0% | 300 |
| **2012** | 7% | -1% | 318 |
| **2013** | 7% | -1% | 337 |
| **2014** | 7% | -2% | 354 |
| **2015** | 7% | -2% | 372 |
| **2016** | 7% | -3% | 386 |
| **2017** | 7% | -3% | 402 |
| **2018** | 7% | -4% | 414 |
| **2019** | 7% | -4% | 426 |
| **2020** | 7% | -5% | 435 |
| **2021** | 7% | -5% | 444 |
| **2022** | 7% | -6% | 448 |
| **2023** | 7% | -6% | 453 |
| **2024** | 7% | -6% | 457 |
| **2025-2030** | 7% | -6% | 462 |

**Figure C-21: Projected Load (MW) from Custom Data Centers**




## *Possible Future Trends for Plug-in Hybrid Electric Vehicles*

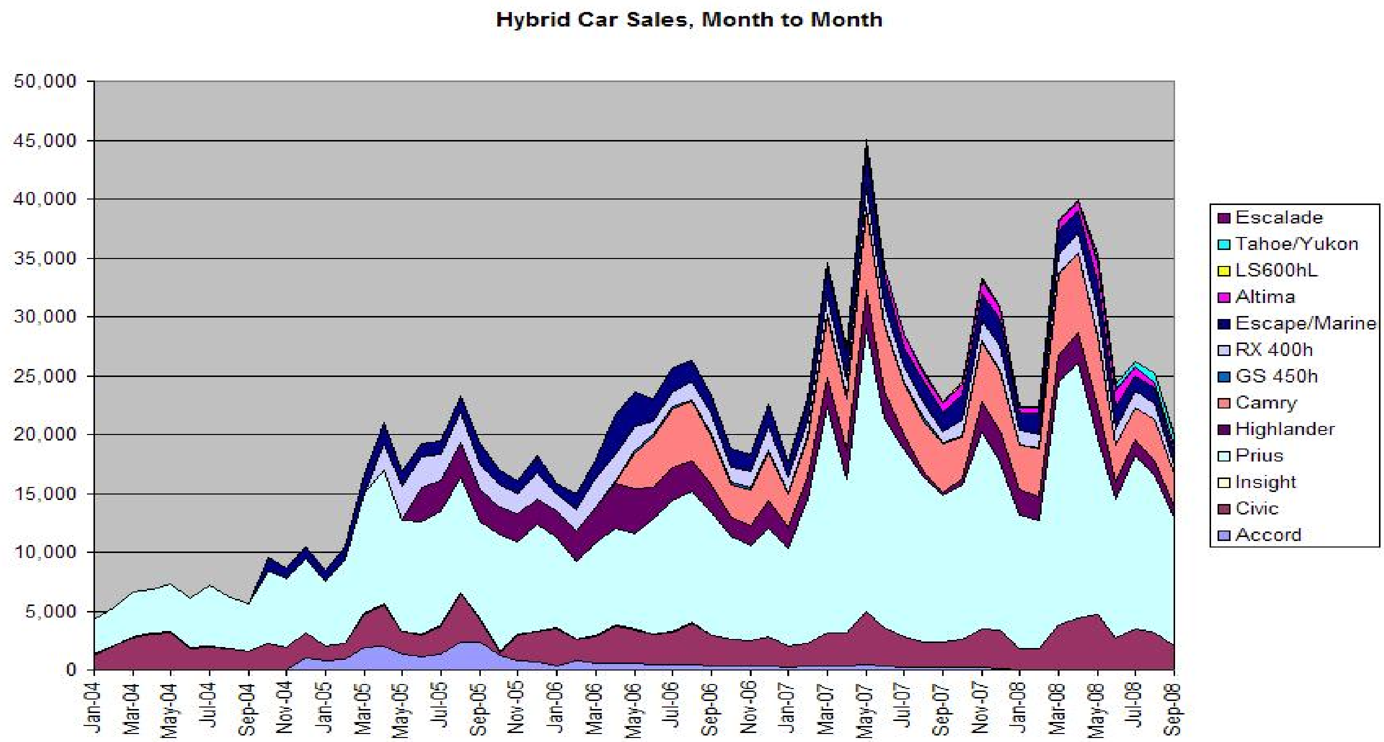
The following is a "What If" analysis concerned with the impact of plug-in electric hybrid vehicles on electrical load in the Northwest over the next 20 years. The Council's analysis is limited to plug-in hybrid vehicle with an electric motor, a plug to recharge the battery and an internal combustion engine.

## Background

Concern for the environment and volatile gasoline prices have created unprecedented interest in alternative fuel and hybrid vehicles. Hybrid vehicles have been available in the U.S. market since 2000 in limited quantities. The hybrid vehicles offered today are powered by internal-combustion engines, with batteries that recharge during driving, and an electric motor to assist with power demand. Hybrids do not need to be plugged in, yet they deliver exceptional mileage compared to their gas-only counterparts. Hybrids are considered environmentally friendly alternatives to traditional internal-combustion vehicles.

Hybrid vehicle sales did not increase substantially until after 2004. According to R. L. Polk and Co., nationwide sales of new hybrid vehicles increased from about 84,000 in 2004 to about 200,000 in 2005; to 250,000 in 2006; and to about 350,000 in 2007. However, in 2008, hybrid vehicle sales were plagued by the same problems as conventional vehicles sales. In 2008, new hybrid vehicle sales declined for the first time due to the housing crisis, credit crunch, and declining fuel prices. Cumulative sales for January through September 2008 were 2 percent lower than the comparable period in 2007.

**Figure C-22: Nationwide Sales of Hybrids 2004-Sep 2008**




Source: R. L. Polk and Co. Hybrid Car Sales, September 2008

Hybrid vehicles usually cost more than comparable conventional vehicles, but they produce significantly lower CO2 emissions. To reduce the lifetime cost of these vehicles, state, federal, and local governments have offered incentives in the form of direct reduced fees (such as registration fees) and tax credits. In the Northwest, Oregon and Washington offer tax incentives for PHEV purchases. Government agencies in Washington, Oregon, and Idaho are required to reduce the petroleum consumption of their fleets by increasing the fuel economy of the vehicles they purchase, and by reducing the number of miles driven by each employee. In the state of

Washington, beginning January 1, 2009, new passenger cars, light-duty trucks, and medium-duty passenger vehicles that are dedicated alternative fuel vehicles (AFVs) are exempt from the state sales and use taxes. Washington agencies must take all reasonable actions to achieve a 20 percent reduction in petroleum use in all state and privately owned vehicles used for state business by September 1, 2009. In Oregon, the Department of Energy offers two income tax credits for alternative and hybrid vehicles for both residents and business owners. Oregon residents are eligible for a residential energy tax credit of up to $1,500 toward the purchase of qualified AFVs.

## Potential Effects on Electricity Demand

Factory-made plug-in hybrid electric vehicles are not currently available to the public. Consumer demand for hybrid vehicles can give us a window into the potential demand for plug-in electric vehicles. More information about marketplace acceptance of these vehicles is needed to be able to forecast their effect on the region's demand. A "what if" analysis was conducted to estimate their potential effect on electricity demand.

According to R. L. Polk and Co., there is a strong relationship between the customer's previously owned vehicle and the size and type of a newly purchased hybrid vehicle, including plug-in hybrids. To analyze the effect of plug-in electric vehicles on electricity demand, the Council used Global Insight's October 2008 forecast scenarios for the total number of new light vehicles. The following table projected new light vehicle sales in the four Northwest states. Three growth rates in new light vehicles and three for penetration rates were considered.

**Table C-18: Projected New Light Vehicles (000)**

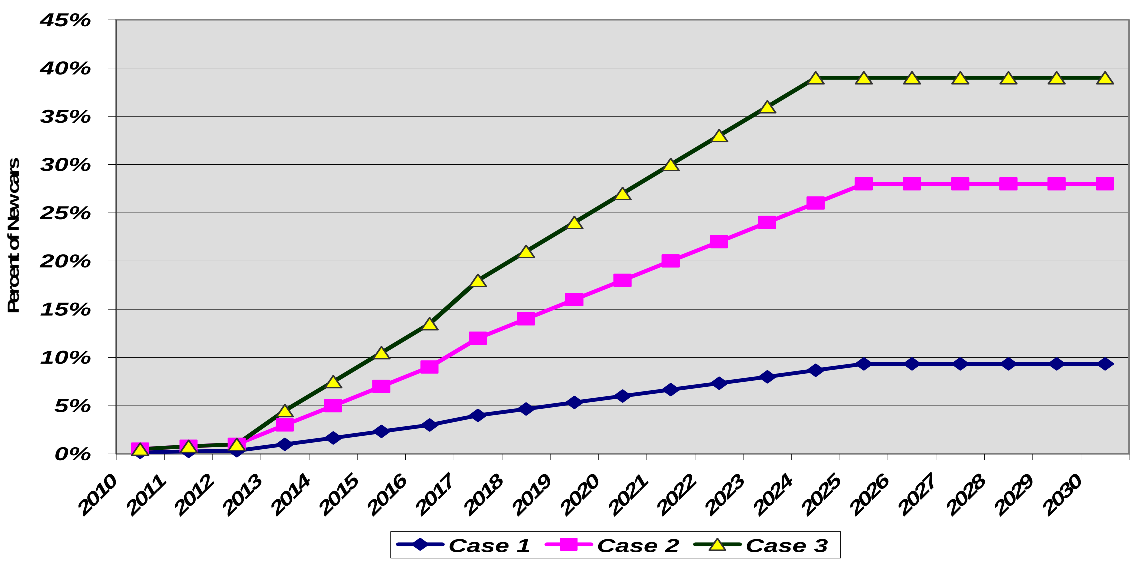
| | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| **2010** | 481 | 606 | 560 |
| **2011** | 513 | 620 | 591 |
| **2012** | 537 | 627 | 616 |
| **2013** | 543 | 632 | 629 |
| **2014** | 548 | 636 | 641 |
| **2015** | 561 | 639 | 659 |
| **2016** | 564 | 640 | 673 |
| **2017** | 565 | 643 | 90 |
| **2018** | 571 | 649 | 706 |
| **2019** | 568 | 658 | 718 |
| **2020** | 560 | 665 | 730 |
| **2021** | 553 | 669 | 749 |
| **2022** | 549 | 675 | 755 |
| **2023** | 545 | 681 | 762 |
| **2024** | 543 | 688 | 774 |
| **2025** | 543 | 696 | 791 |
| **2026** | 543 | 704 | 806 |
| **2027** | 543 | 710 | 819 |
| **2028** | 542 | 717 | 837 |
| **2029** | 543 | 724 | 856 |
| **2030** | 543 | 732 | 878 |

The penetration rate for plug-in electric vehicles will be limited. The case 1 scenario assumes a 0.5 percent penetration rate for 2010. By 2025, it is assumed that 28 percent of new light vehicles could be plug-in hybrids. In the high-penetration scenario, case 3, it is assumed that 39 percent of new vehicles will be plug-in electric by 2025. In the low-penetration scenario, case 1, plug-in electric vehicles are assumed to represent 9 percent of the new car market by 2025.

**Table C-19: Penetration Rate and Cumulative Number of PHEV in the Region (000)**

| | Case 1 | Case 2 | Case 3 | Case 1 | Case 2 | Case 3 |
|---|---|---|---|---|---|---|
| **2010** | 0.2% | 0.5% | 0.5% | 1 | 3 | 3 |
| **2011** | 0.3% | 0.8% | 0.8% | 2 | 7 | 8 |
| **2012** | 0.3% | 1.0% | 1.0% | 4 | 13 | 14 |
| **2013** | 1.0% | 3.0% | 4.5% | 9 | 31 | 42 |
| **2014** | 1.7% | 5.0% | 7.5% | 19 | 61 | 90 |
| **2015** | 2.3% | 7.0% | 10.5% | 32 | 104 | 157 |
| **2016** | 3.0% | 9.0% | 13.5% | 49 | 159 | 244 |
| **2017** | 4.0% | 12.0% | 18.0% | 71 | 235 | 359 |
| **2018** | 4.7% | 14.0% | 21.0% | 98 | 324 | 496 |
| **2019** | 5.3% | 16.0% | 24.0% | 128 | 426 | 654 |
| **2020** | 6.0% | 18.0% | 27.0% | 162 | 541 | 833 |
| **2021** | 6.7% | 20.0% | 30.0% | 199 | 669 | 1034 |
| **2022** | 7.3% | 22.0% | 33.0% | 239 | 811 | 1257 |
| **2023** | 8.0% | 24.0% | 36.0% | 282 | 966 | 1502 |
| **2024** | 8.7% | 26.0% | 39.0% | 329 | 1135 | 1770 |
| **2025** | 9.3% | 28.0% | 39.0% | 380 | 1320 | 2042 |
| **2026** | 9.3% | 28.0% | 39.0% | 431 | 1506 | 2316 |
| **2027** | 9.3% | 28.0% | 39.0% | 481 | 1694 | 2593 |
| **2028** | 9.3% | 28.0% | 39.0% | 532 | 1884 | 2873 |
| **2029** | 9.3% | 28.0% | 39.0% | 583 | 2077 | 3155 |
| **2030** | 9.3% | 28.0% | 39.0% | 633 | 2272 | 3441 |

**Figure C-23: Assumed Market Penetration Rates for New PHEV**



Plug-in hybrid electric vehicles were assumed to have an average energy requirement of 0.3 KWh/mile. The analysis focused on a composite of three types of cars: a compact sedan, a mid-size sedan, and a mid-size SUV ranging from 0.26 to 0.46 KWh/mile to create a "typical" PHEV. For this composite vehicle, a Lithium-ion battery sized to 10 kilowatt hours is assumed to power the vehicle. It was also assumed that the energy efficiency of the vehicle would improve at a rate of 5 percent per year.

These vehicles are assumed to travel 33 miles per day, the current average. The battery recharge profile for PHEV is important in order to estimate their demand on the electric grid. It was assumed that 95 percent of cars would be charged between 7 p.m. and 7 a.m., and 5 percent of the vehicles would be charged between 8 a.m. and 6 p.m. Recharging at 110 volt, 15 amp was assumed to take eight hours or less; at 220 volt, 30 AMP, the vehicle would be charged in less than two hours. The current average efficiency of gasoline-powered fleet vehicles is assumed to be 20.2 MPG and improving to 35 MPG by 2020. Based on these assumptions, electricity demand for each scenario was projected. The following figure shows the annual energy and peak and off-peak demand requirements of plug-in hybrid vehicles in the Northwest.

Given these assumptions, plug-in electric vehicles are forecast to increase the regional load between 100 to 550 average megawatts by 2030. The increase in load would be gradual and would have a minimal impact on regional load in the first 5 to 10 years of introduction into the market. Their impact on system load would be greater during off-peak hours, given the recharge assumption. It is projected that off-peak loads would increase by 200-1,000 megawatts. The impact of PHEV on system peak is projected to be much smaller, 5-25 megawatts, given the assumption that only 5 percent of vehicles will recharge during the peak period.

**Figure C-24: Projected Load from Plug-in Hybrid Vehicles**

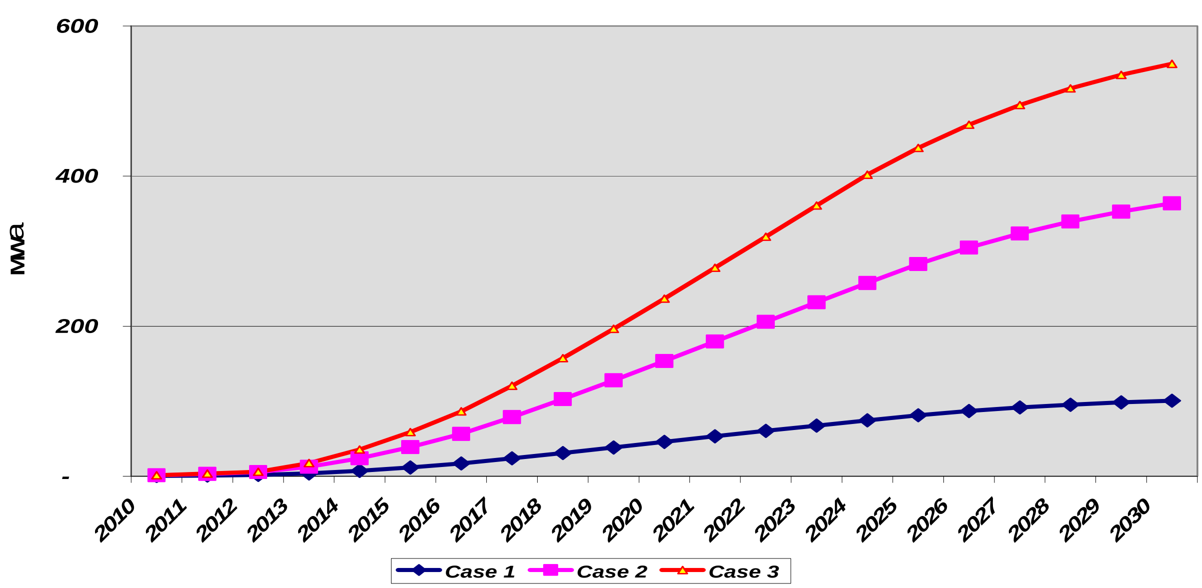
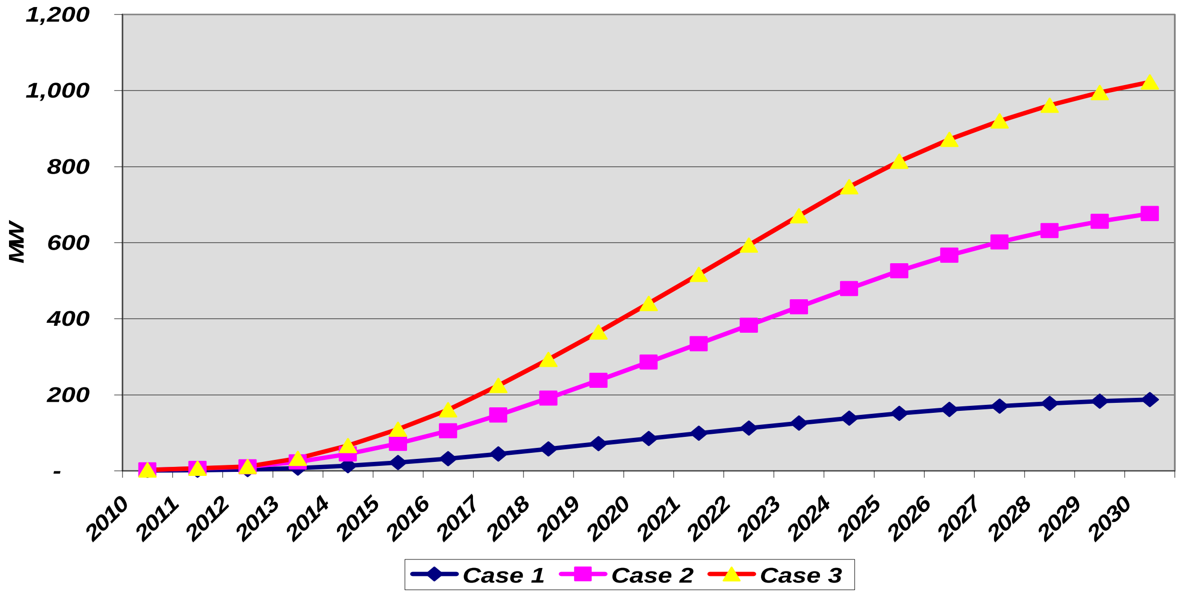


**Figure C-25: Project Off-peak Load from Plug-in Hybrid Vehicles**



# Appendix D: Wholesale Electricity Price Forecast

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## INTRODUCTION

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices. This forecast is used to establish benchmark capacity and energy costs for conservation and generating resource assessments for the Council's power plan. The forecast establishes the base electricity market price for the Council's Resource Portfolio Model and is used in the ProCost model by the Regional Technical Forum to assess the cost-effectiveness of conservation measures. The Council's price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans and for other purposes.

The Council uses the AURORA$^{xmp®}$ Electric Market Model[1] to forecast wholesale power prices. AURORA$^{xmp®}$ provides the ability to incorporate assumptions regarding forecast load growth, future fuel prices, new resource costs, capacity reserve requirements, climate control regulation and renewable portfolio standard resource development into its forecasts of future wholesale power prices. The forecasting model can also be used for analysis of issues related to power system composition and operation, such as the effectiveness of greenhouse gas control policies.

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. The

[1] The AURORA$^{xmp}$ Electric Market Model, available from EPIS, Inc (http://www.epis.com).

forecast represents the price of a flat hourly energy delivered to a wholesale delivery points (i.e. inclusive of integration and transmission costs). Unless otherwise stated, the prices reported in this appendix are for the "PNW Eastside" load-resource area defined as Washington and Oregon east of the Cascades, Northern Idaho and Montana west of the Continental Divide. Prices in this area are considered to be representative of Mid-Columbia transactions. Other zonal series are available from the Council on request.

The Council's wholesale power price forecast has been used by others as a measure of avoided resource cost. The Council cautions that this price forecast may not be a suitable stand-alone measure of avoided resource costs. This issue is further discussed in the "Avoided Resource Cost" section of this appendix.

The annual and monthly Base case forecast values are provided in tables at the end of this Appendix. Hourly values for the Base case and values for the sensitivity cases are available from the Council on request. All prices are in constant 2006 year dollar values unless otherwise indicated.

## SUMMARY OF KEY FINDINGS

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide ($CO_2$) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

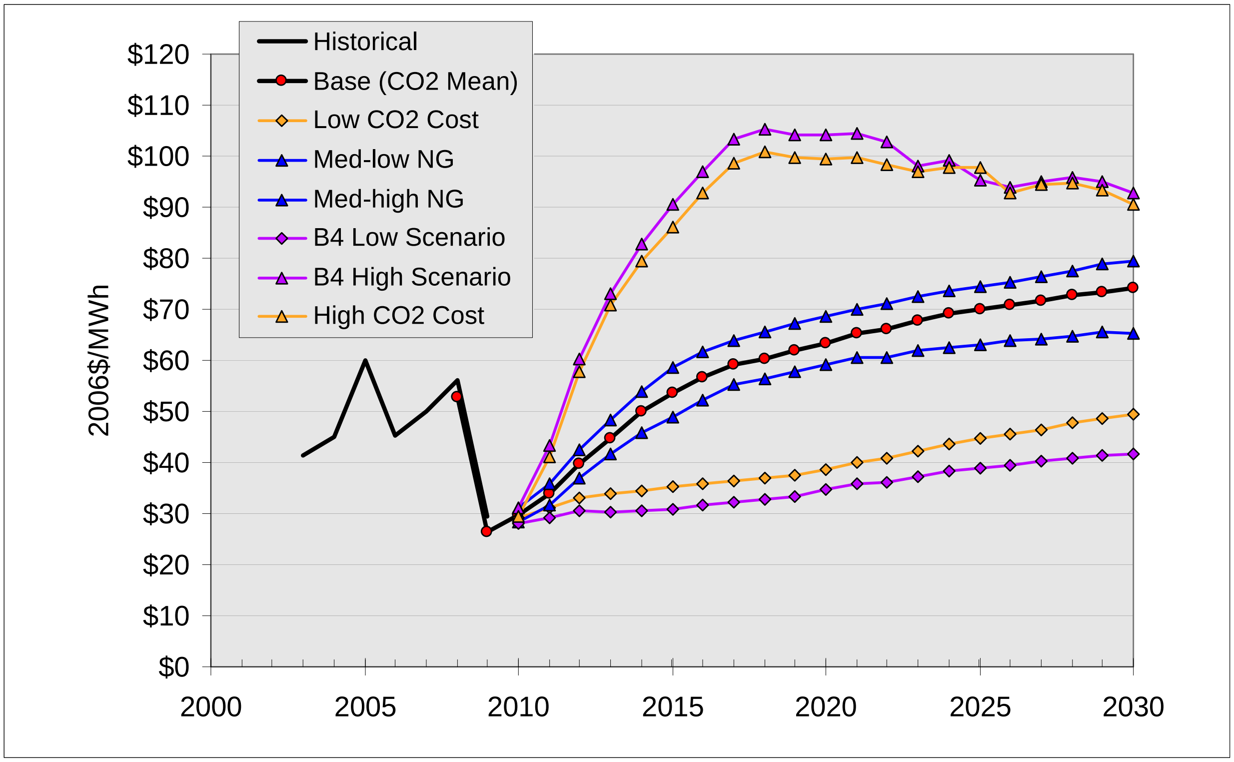
Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. $CO_2$ allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower $CO_2$ costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High $CO_2$ costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. State RPS are expected to force the development of large amounts of wind, solar and other low-variable cost resources, in excess of the growth in demand. This will force lower variable cost fossil units to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding scenario cases were run. The base case assumes medium case fuel prices and mean $CO_2$ prices. All forecast cases assume 95 percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are as follows:

| Case | Fuel Prices | $CO_2$ Cost |
|---|---|---|
| **Base** | Medium Case | Mean of RPM $0 -100 case |
| **Low $CO_2$ Cost** | Medium Case | 90% prob. of exceedance decile |
| **High $CO_2$ Cost** | Medium Case | 10% prob. of exceedance decile |
| **Medium-Low Natural Gas** | Medium-low NG | Mean of RPM $0 -100 case |
| **Medium-High Natural Gas** | Medium-high NG | Mean of RPM $0 -100 case |
| **Low Scenario** | Medium-low NG | 90% prob. of exceedance decile |
| **High Scenario** | Medium-high NG | 10% prob. of exceedance decile |

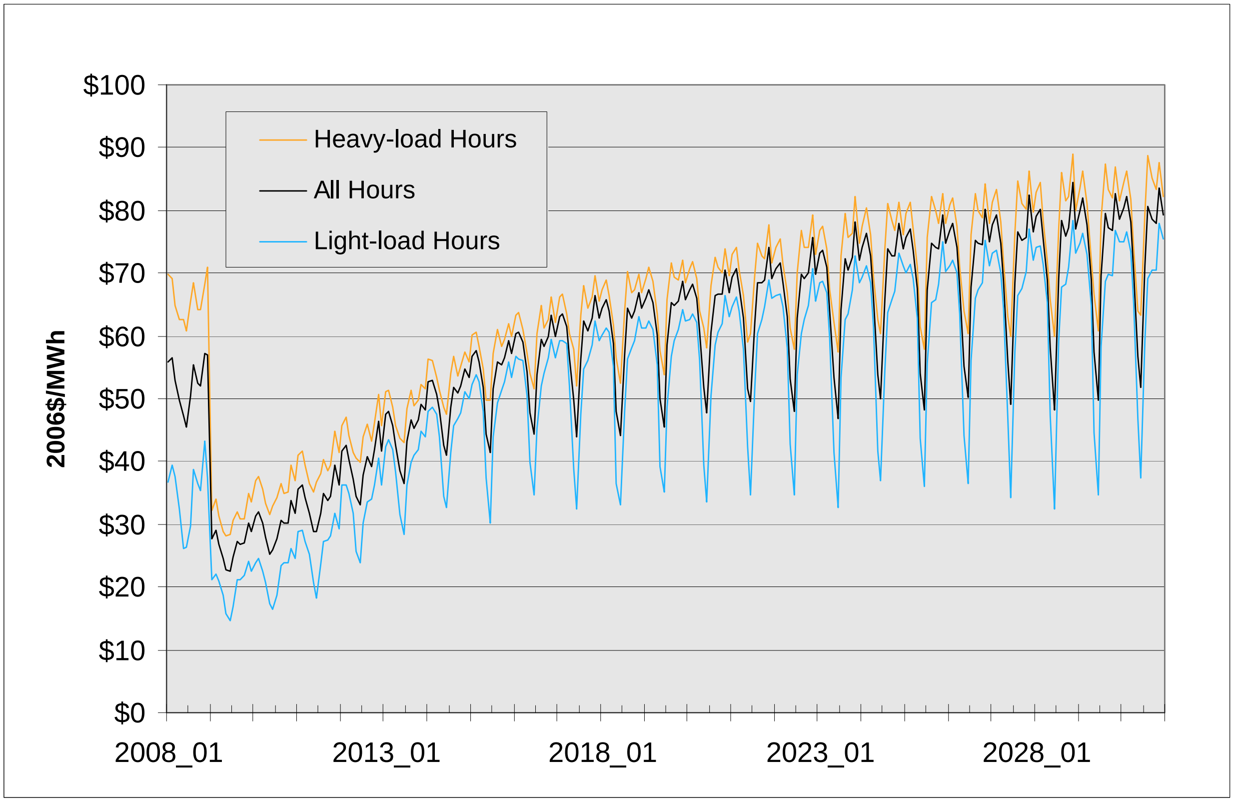
For the Base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $30 per megawatt-hour in 2010 to $74 per megawatt-hour in 2030 (real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to $29 in 2009 with collapse of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 Base case forecast is $56 per megawatt-hour. Figure D-1 illustrates recent historical prices and forecast wholesale power prices for the cases.

**Figure D-1: Historical and Forecast Annual Average Mid-Columbia Wholesale Power Prices**




Northwest electricity prices exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure D-2 shows the monthly average heavy-load hours, all hours, and light-load hours prices for the Base forecast.

**Figure D-2: Monthly Average Base Case Forecast of Mid-Columbia Wholesale Power Prices**




# APPROACH AND METHODOLOGY

The Council uses the AURORA$^{xmp®}$ Electricity Market Model[2] to forecast wholesale power prices. Hourly prices are based on the variable cost of the most expensive (in variable terms) generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. AURORA$^{xmp®}$, as configured by the Council, simulates plant dispatch in each of 16 load-resource areas making up the Western Electricity Coordinating Council (WECC) electric reliability area (Figure D-3). Four of these areas comprise the four Northwest states: Eastern Oregon and Washington, northern Idaho and Western Montana (Pacific Northwest Eastside, Area 1); southern Idaho (Area 5), Eastern Montana (Area 6), and Western Oregon and Washington (Pacific Northwest Westside, Area 16).

These areas 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 load-resource load-resource areas are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource area may be served by native generation, curtailment, or by imports from other load-resource areas if economic, and if transmission transfer capability is available.

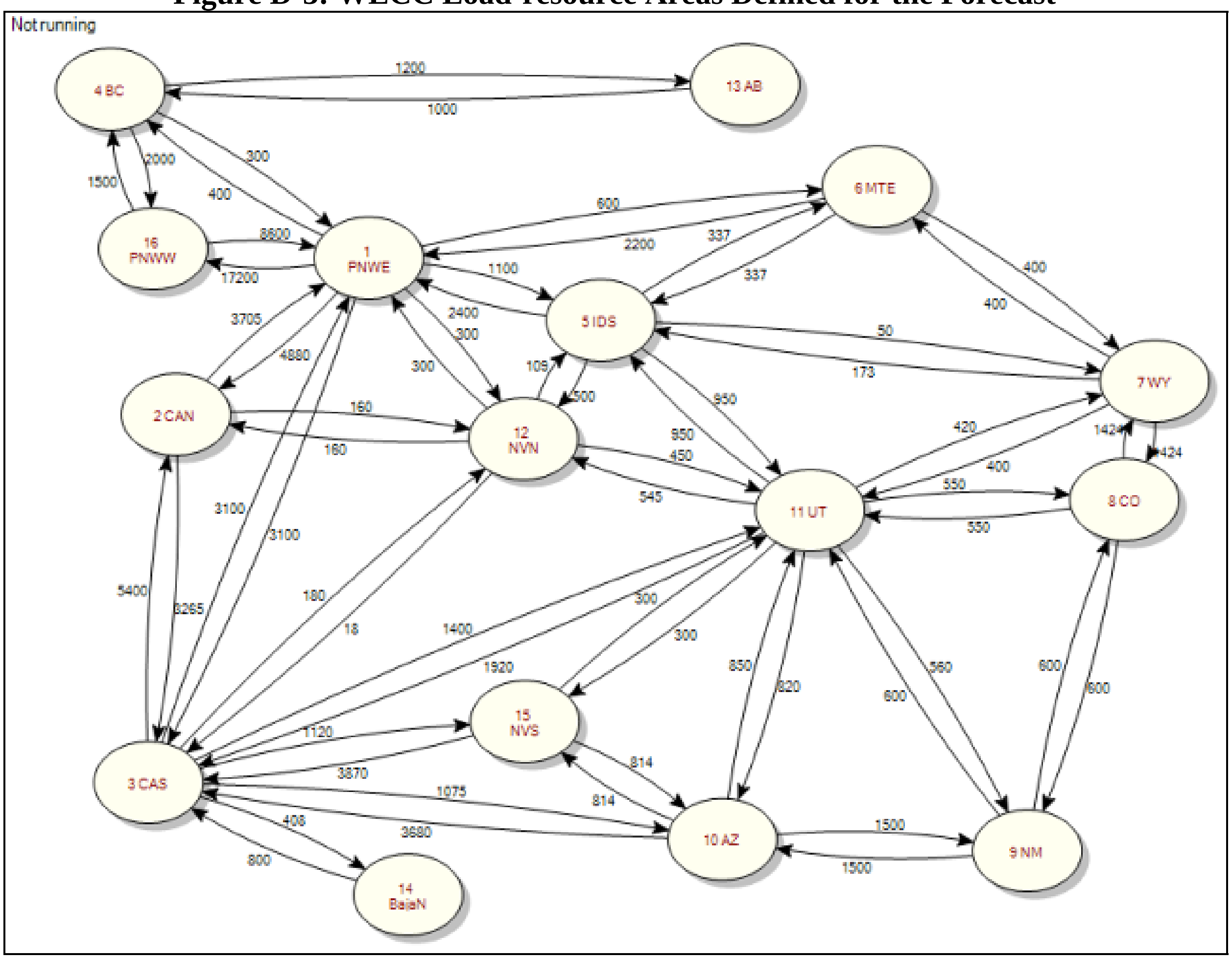
[2] Supplied by EPIS, Inc. (www.epis.com). AURORA$^{xmp}$ Version 9.6.1011 was used for the final Sixth Power Plan forecasts described here.

A forecast is developed using the two-step process. First, a forecast of capacity additions and retirements economically supply energy to the system while maintaining firm capacity standard 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.

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. Every-hour dispatch more accurately models the interaction of system resources than the sampling process used for the capacity expansion step. Power plant ramping limits and the full representative hourly output of wind and other variable resources are incorporated in this step to more accurately portray system operation. 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 for that hour.

The price forecast developed for Area 1 (Pacific Northwest Eastside) is considered representative of Mid-Columbia trading hub prices.

**Figure D-3: WECC Load-resource Areas Defined for the Forecast**



The final price forecast consists of a base case, corresponding to the mean or average values of variables such as demand growth, fuel prices, hydro conditions and forecast carbon dioxide allowance prices (or tax cost). Sensitivity cases were run to test the effect of higher or $CO_2$ costs and higher and lower natural gas prices. Finally, two bounding scenarios were run, representing concurrent low natural gas and $CO_2$ prices and high natural gas and $CO_2$ prices.

# ASSUMPTIONS

## *Demand*

Energy and peak load forecasts for the four Northwest areas are provided by the Council's demand forecast model. Council staff projected both energy and peak demand growth for nine of the remaining 12 areas (those in the U.S.) based on 2008-2017 forecasts submitted to the FERC (EIA Form 714) by electric utilities. The forecast for Alberta for the same years was based on the forecast by the Alberta Electric System Operator (AESO).[3] The Council's forecast for British Columbia was based on a forecast BC Hydro submitted to the Western Electricity Coordinating Council (WECC) for the period 2010-2017, supplemented by data from the British Columbia Transmission Corporation (BCTC)[4] for 2007 and interpolation for 2008 and 2009. The forecast load for northern Baja California in Mexico was based on the forecast submitted to WECC for 2010-2017, the 2006 load previously used by AURORA, and interpolated values for 2007-2009.

AURORA$^{xmp}$ requires load projections for each year to 2053. For most load-resource areas, Council staff extended the forecasts past 2017 by calculating a 5-year rolling average for the previous five years. Arizona and New Mexico loads were projected to grow from 2021 through 2027 at the same rate as the projected population growth in each state. After 2027, load was projected to continue to grow at the 2027 rate. The load for northern Baja California was similarly projected, except that the population growth rate for New Mexico was used for 2021-2027 (population projections for Baja California were unavailable).

The forecasted energy loads of the 16 load-resource areas are illustrated in Figure D-3. Tabular data is provided in Table D-1.

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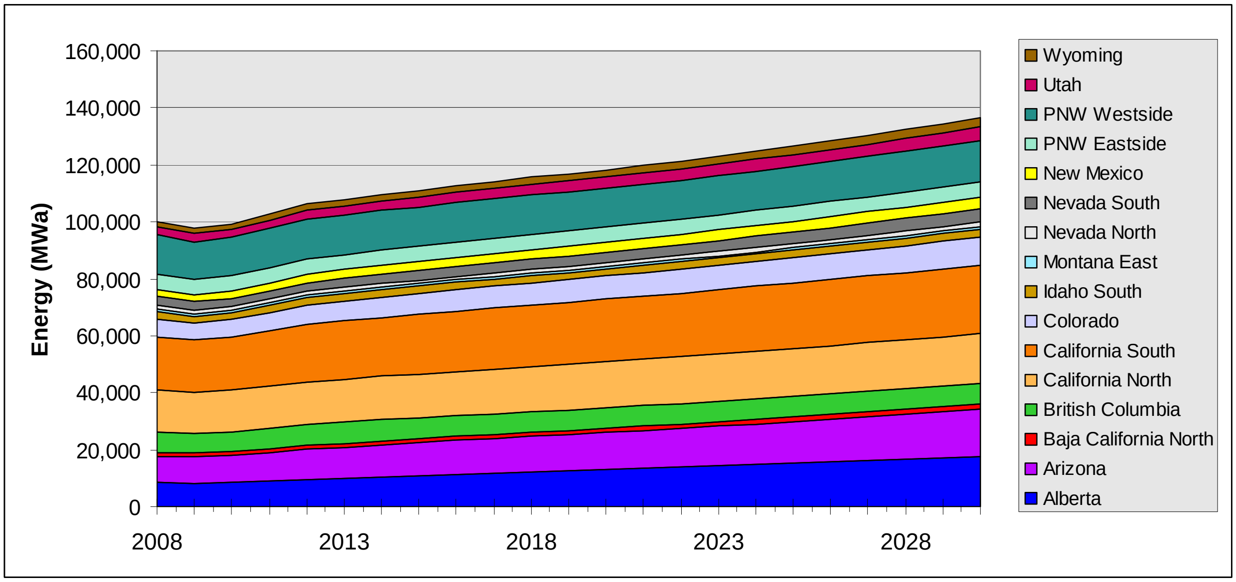
[3] http://www.aeso.ca/downloads/Future_Demand_and_Energy_Outlook_(FC2007_-_December_2007).pdf
[4] http://www.bctc.com/NR/rdonlyres/C6E06392-7235-4F39-ADCD-D58A70D493C7/0/2006controlareaload.xls

**Figure D-4: Forecasted Energy Loads for the Load-resource Areas**




## *Firm Capacity Standards*

The firm capacity standard represents a requirement that a region's generating resources provide enough firm capacity to meet the region's peak demand plus a specified margin for reliability considerations. The model uses two input parameters to simulate achievement of a region's firm capacity standard. The first is a planning reserve margin target for each region. The second is a firm capacity credit for each type of generating resource.

### Planning Reserve Margin Targets

Reserve margin targets can be specified for each load-resource area, for an aggregation of load-resource areas called an operating pool, or for both. The Council has specified planning reserve margin targets for two operating pools: (1) the Pacific Northwest region, except Southern Idaho, and (2) the California Independent System Operator (CAISO). The remaining load-resource areas are given individual reserve margin targets. Southern Idaho was not modeled within the Northwest pool because of existing transfer constraints between southern Idaho and the rest of the region.

For the CAISO and the stand-alone areas other than Southern Idaho, the planning reserve margin target was set at 15 percent. For the Pacific Northwest, including Southern Idaho, the Council configured AURORA$^{xmp}$ to reflect the capacity standard of the Pacific Northwest Resource Adequacy Forum. The adequacy forum has determined that reserve margin targets of 25 percent in winter and 19 percent in summer correspond to an overall system loss-of-load probability of 5 percent.

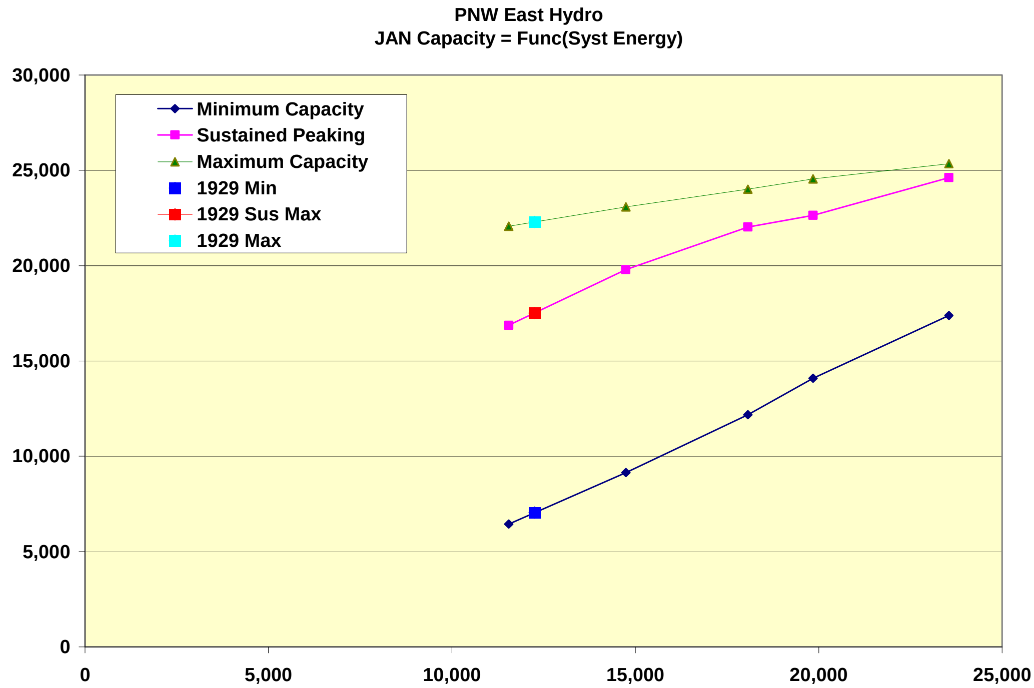
The Adequacy Forum targets reflect a specific set of resource and load assumptions that cannot be easily replicated in AURORA$^{xmp}$. For example, the winter reserve margin target is based on consideration of the highest average demand for a three-day 18-hour sustained peak period, while AURORA$^{xmp}$ is limited to consideration of the single highest hour of demand. Moreover, multi-seasonal reserve margin targets cannot be input directly into AURORA$^{xmp}$. For electricity price forecasting purposes, the Council converted the Adequacy Forum's multiple-hour capacity reserve margin targets to an equivalent single-hour target. Adjustments were also made to reflect consistent treatment of spot market imports, hydro conditions and flexibility, and independent power producer generation. The equivalent single-hour winter capacity reserve margin for the Northwest is 18 percent. Conversion of the adequacy forum's capacity reserve margin targets does not reflect a change in the adequacy standard, but rather an adjustment to approximate the complex Northwest standards using the simpler reserve parameters available in AURORA$^{xmp}$. Both the forum's target and the target used in AURORA$^{xmp}$ reflect an overall loss-of-load probability of 5 percent for the Northwest.

## Firm Capacity Credit

The second input parameter used to simulate achievement of firm capacity standards is the firm capacity credit for each type of generating resource. The firm capacity credit is often referred to as resource type's peak contribution or its expected availability at the time of peak demand. For a generating resource that is fully dispatchable, the peak contribution is net installed capacity less its forced outage rate. The Council uses a firm capacity credit for thermal resources in the range of 90 to 95 percent of installed capacity (See Appendix I for specific values for each resource type). The Council uses the firm capacity credit of 5 percent for wind resources adopted by the Reliability Forum, and an provisional value of 30 percent for solar photovoltaic resources. For the Pacific Northwest's hydro resources, the Council uses a winter single-hour firm capacity credit of 82 percent on installed capacity for east-side hydro and 83 percent for west-side hydro. 95 percent is used for hydropower in other load resource areas.

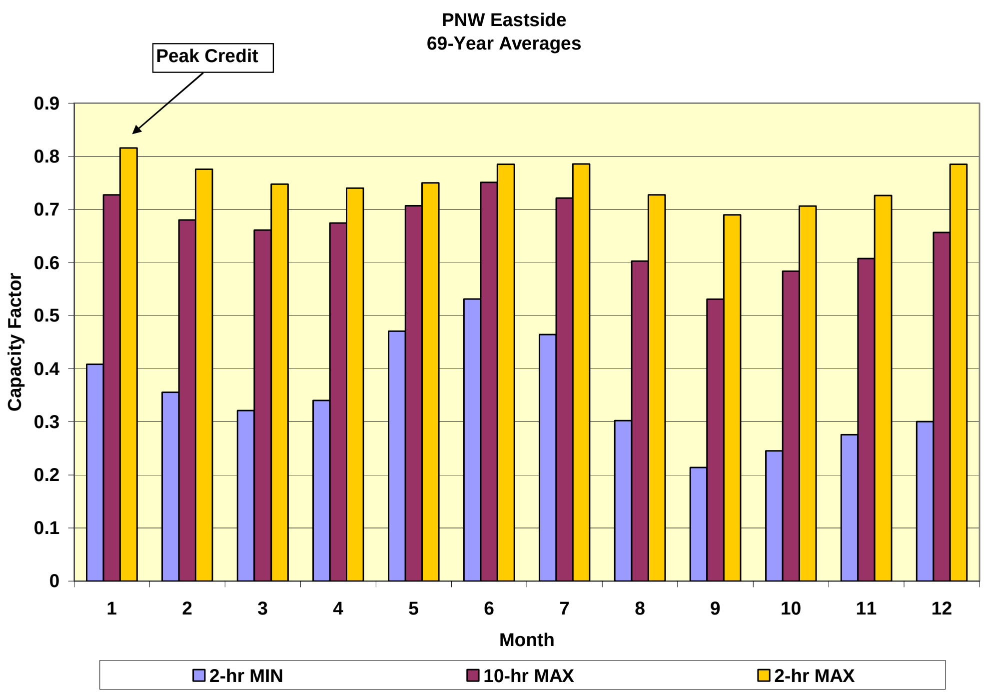
The firm capacity credits for Pacific Northwest hydro resources are based on two-hour sustained peaking capacity estimates developed for the Pacific Northwest Resource Adequacy Forum. Figure D-5 shows the January peaking capability of Pacific Northwest Eastside hydro resources as a function of monthly energy output. On the horizontal axis, the average monthly energy output of these hydro resources can be seen to range from 11,000 to 24,000 megawatts, depending upon streamflow conditions. On the vertical axis, the curve at the top of the chart represents the two-hour sustained peak output of these hydro resources across the range of monthly output. For example, given 1929 streamflows yielding a monthly energy output of 12,000 average megawatts, the east-side hydro resources would be expected to provide roughly 22,000 megawatts of firm capacity over a two-hour peak period.

**Figure D-5: Example Calculation of Pacific Northwest Eastside January Sustained Peaking Capacity (1929 streamflow conditions)**




The Council has calculated the two-hour sustained peaking capacity credit for both Eastside and Westside hydro resources by month for each of the 69 calendar years in the Pacific Northwest streamflow record. Figure D-6 shows the two-hour sustained peaking capacity for Eastside hydro resources by month. For hydro modeling in AURORA$^{xmp}$, the Council uses the January values of 82 percent of installed capacity for Eastside hydro resources and 83 percent for Westside hydro resources (derived in a similar manner).

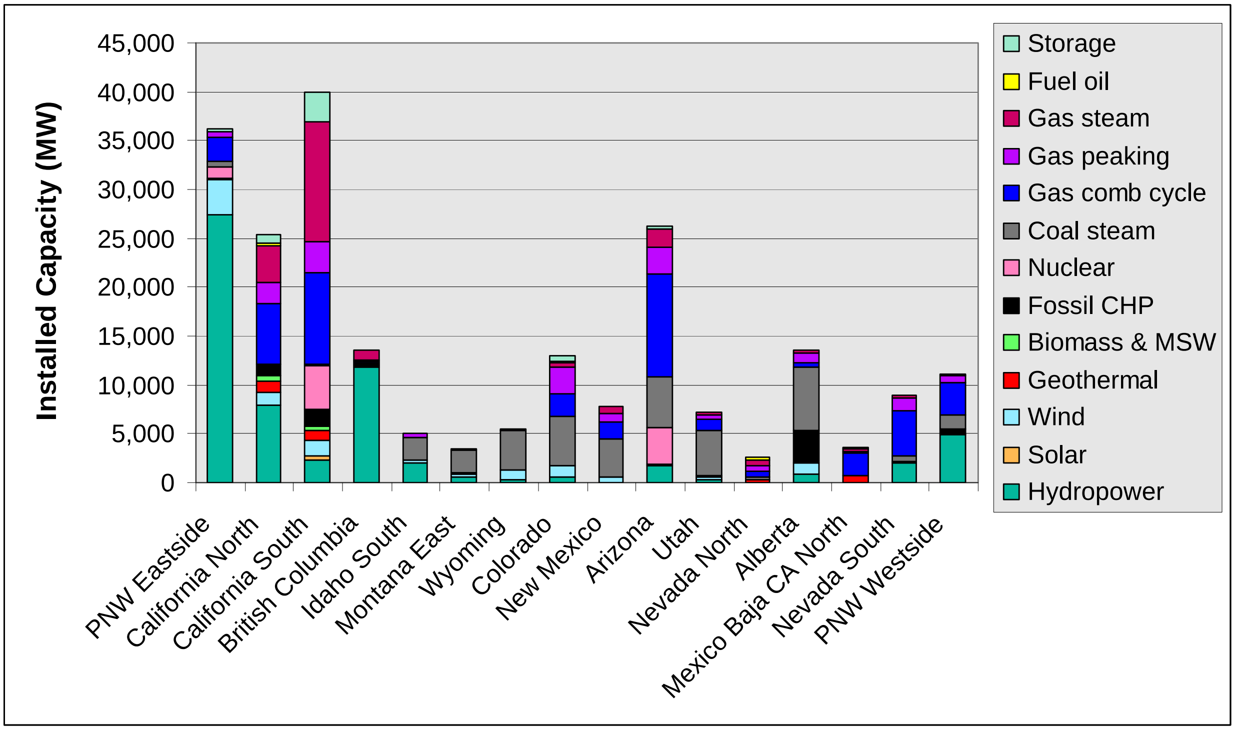
**Figure D-6:  PNW Eastside Hydropower, 69-year Average**




## *Existing Resources*

AURORA[xmp] capacity expansion studies commence with the generating resources of the existing power system.  For purposes of this forecast, "existing resources" are those in operation or under construction as of September 2009.  The database of existing resources was updated using WECC data, the Council's database of Northwest power plants, information regarding new power plants maintained by the Council for cost-estimating purposes and other sources.  The existing WECC generating resource mix by load-resource area is illustrated in Figure D-7.

**Figure D-7: 2009 Resource Mix by Load-resource Area**




## *New Resource Options*

The first step in developing the forecast is to run AURORA$^{xmp}$ using the model's long-term resource optimization logic to produce a forecast of resource additions and retirements. New resource options are provided for the model to draw upon for this purpose. Resources, such as biogas, available in relatively small quantity were omitted from the set of resource options because their absence is not expected to significantly affect future power prices and because most of these resources are expected to be developed in response to state renewable portfolio standards.

The cost and operating characteristics of the new resource options are based on the assessment of new resource options prepared by the Council for the Pacific Northwest as described in Chapter 6 and Appendix I of this plan. The output of combustion turbine-based technologies was adjusted to reflect the elevation of representative sites within the various load-resource areas. Also, the capacity factors of solar and wind resource options were adjusted to reflect typical performance within the various load-resource areas. Representative solar parabolic trough and solar photovoltaic plant hourly output was developed using the NREL Solar Advisor Model[5], as described in Appendix I. Hourly wind output estimates were developed from the hourly wind profiles for representative wind resource areas compiled by WECC staff from the National Renewable Engineering Laboratory mesoscale wind data base.

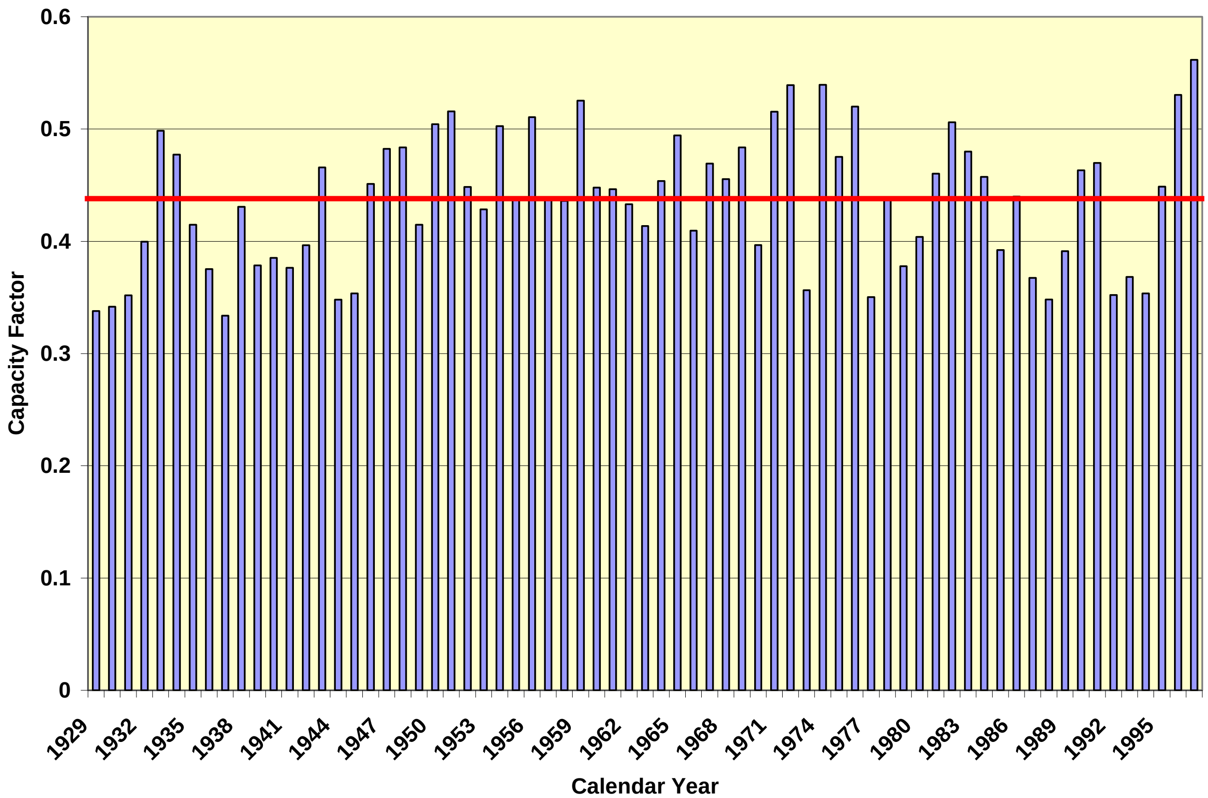
Characteristics of the new resource options used for this forecast are summarized in Table D-2. Additional information regarding these options is provided in Chapter 6 and Appendix I.

[5] www.nrel.gov/analysis/sam/

## *Pacific Northwest Hydro Modeling*

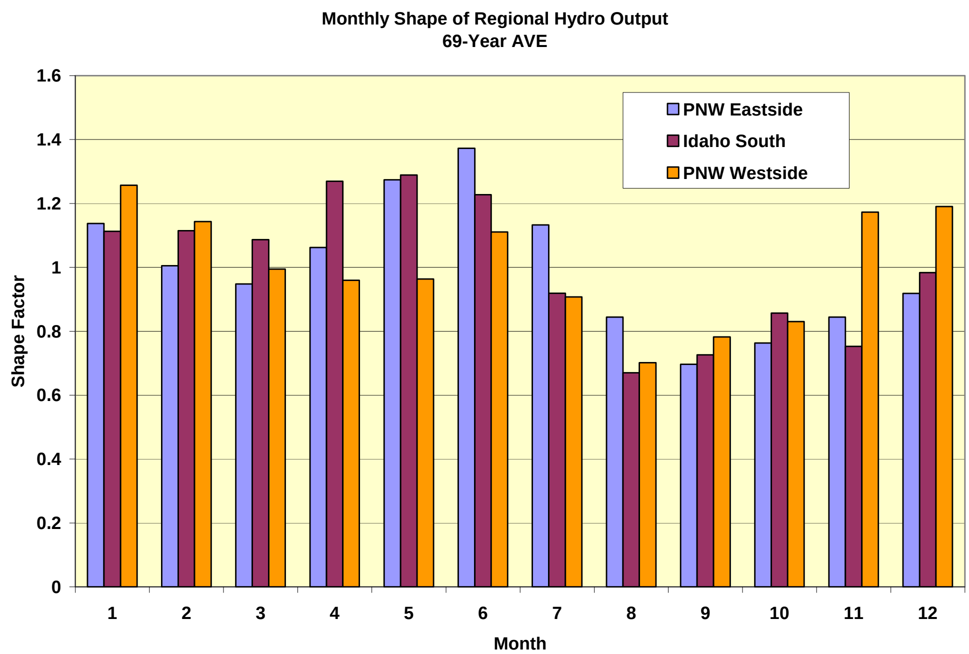
Pacific Northwest modified streamflow data is available for the period September 1928 through August 1998. The Council uses its GENESYS model to estimate the hydroelectric generation that would be expected from this streamflow record given today's level of river system development and environmental protection. To simulate Pacific Northwest hydroelectric generation in AURORA$^{xmp}$, annual average capacity factors are calculated for the hydro resources of the Pacific Northwest Eastside; Pacific Northwest Westside; and Southern Idaho load-resource areas. Figure D-8 shows the annual capacity factors of the Pacific Northwest Eastside hydro resources given the modified streamflow record for the period January 1929 through December 1997. The 69-year average capacity factor is 44 percent of nameplate capacity.

**Figure D-8: Annual Capacity Factor of Pacific Northwest Eastside Hydropower Resources**




The seasonality of hydropower production is modeled in AURORA$^{xmp}$ by use of monthly shaping factors. The average monthly hydropower output for the 69-year annual record is shown in Figure D-9.

**Figure D-9: Northwest hydropower monthly shape factors, 69 Year Avg.**




## *State Renewable Portfolio Standards*

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the WECC: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon and Washington[6]. In addition, British Columbia has adopted an energy plan with conservation and renewable energy goals equivalent to an aggressive RPS. Important characteristics of the state renewable portfolio standards are shown in table D-4. State RPS laws are complex with great variation between states and are often amended. Current information regarding state renewable portfolio standards are documented at www.dsireusa.org. The applicable elements of the British Columbia energy policy, adopted in 2007 can be summarized as a series of paraphrased policy statements:

- All new electricity generation projects shall have zero greenhouse gas emissions
- All existing thermal shall have zero greenhouse gas emissions by 2016.
- Renewable energy sources will continue to account for at least 90 % of generation.
- No nuclear power.
- 50% of new resource needs through 2020 will be met by conservation.

Mandatory development of low variable-cost renewable resources can significantly affect wholesale power prices and the need for discretionary resources. A forecast of the types of renewable resources that may be developed and the success in achieving the targets is needed for

[6] Utah's *Energy Resource and Carbon Emission Reduction Initiative* adopted in 2008 has characteristics of a renewable portfolio standard, but mandates acquisition of qualifying resources only if cost-effective. Because resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA[xmp®] Electricity Market Model used for the wholesale power price forecast was not forecast.

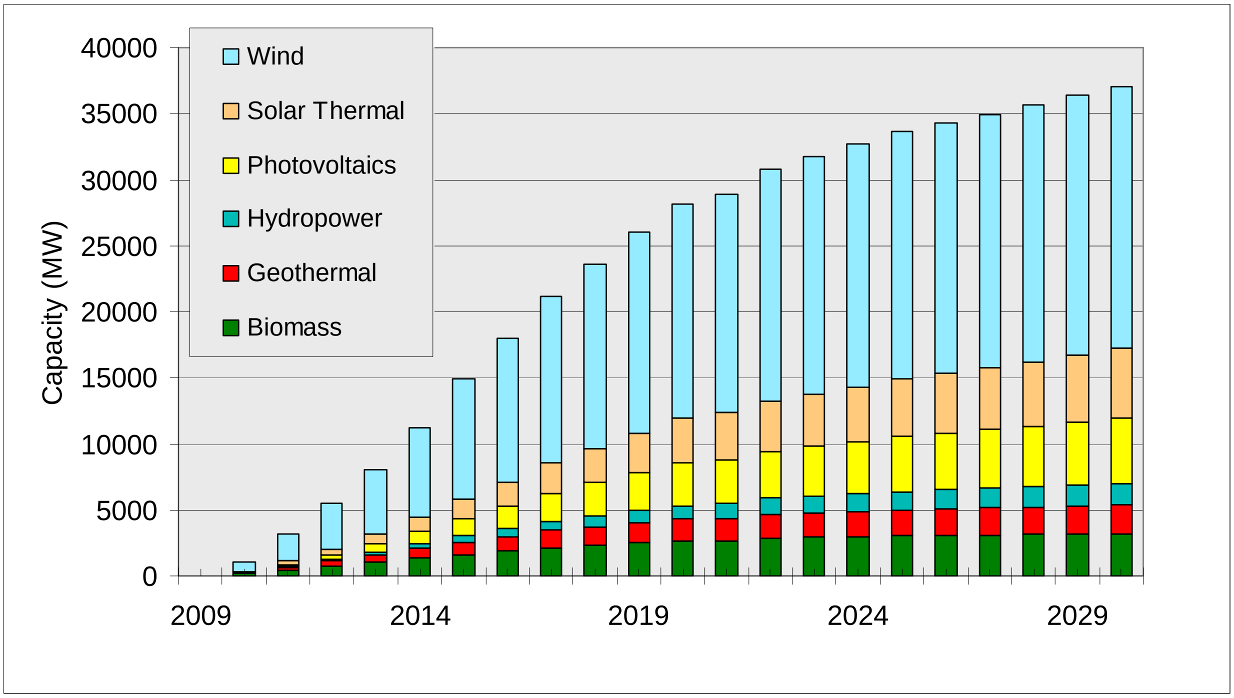
the wholesale power price forecast and the resource portfolio analysis.  The resulting estimate of need for new renewable energy to fully meet state RPS obligations is provided in Table D-43

Because of price caps, observed lags in some states, and the increasing cost and difficulty of securing qualifying resources as demand increases, acquisition of qualifying resources is unlikely to meet targets in some states.  This forecast assumes 95 percent achievement of standards (i.e, 95 percent of the new energy of Table D-3).  All potentially qualifying existing plants are assumed to be credited.  Energy-efficiency measures, in states where credited, are assumed to be employed to the extent allowed.

RPS obligations will be met by a mix of new resources, determined by state-specific resource eligibility criteria, new resource availability, resource cost, policies governing out-of-state resources, resource set-asides and special credit and other factors.  New RPS resource development in the near-term was assumed to resemble the composition of recent RPS resource development.  Development is assumed to shift over time toward locally abundant, but relatively undeveloped resources such as solar thermal as the cost-effectiveness of these resources improves.  Figure D-10 illustrates the assumed incremental capacity additions needed to provide 95 percent of the cumulative energy requirements of Table D-4.

As a simplifying assumption, the Council assumed that all new RPS resource requirements would be met in-state, though it is clear that states such as California, with substantial need for qualifying RPS resources, will secure much of its RPS needs from out-of-state sources.

**Figure D-10:  WECC Cumulative Renewable Portfolio Standard Capacity Additions**




## *Fuel Prices*

The coal and natural gas prices used for the draft forecast are based on the Council's fuel price forecast, described in Appendix A.

The Council forecasts the variable and fixed cost of coal delivered to each load-resource area using a reference mine-mouth price plus transportation cost. Powder River Basin (PRB) coal is the reference. The variable delivered coal cost is the sum of the mine-mouth price, plus the variable cost of transportation to each load-resource area. The variable costs of transportation are based on average coal transportation rates and average shipment distances from Wyoming to each load-resource area.

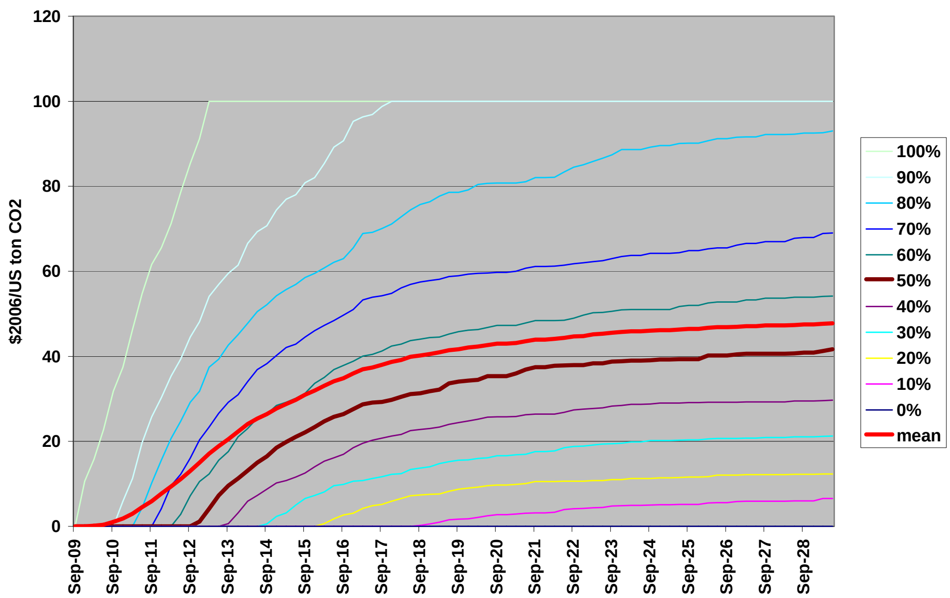
The Council's underlying forecast of natural gas prices is described in Appendix A. Development of the estimated delivered cost of natural gas for each load-resource area is described in Appendix A.

The nuclear and biomass fuel price forecasts are described in Appendix I.

## *Carbon Dioxide Prices*

The Council's studies use a fuel carbon content tax as a proxy for the cost of carbon dioxide control, whether it be by cap and trade allowances or by tax. The $CO_2$ allowance cost values used for this forecast are derived from the range of possible $CO_2$ costs developed for the resource portfolio risk analysis (Figure D-11).

**Figure D-11: Decile chart of forecast $CO_2$ prices**




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

The Base case forecast used the mean value of $CO_2$ prices from the $0 - 100 Carbon Risk Case of the resource portfolio analysis. This price series is depicted by the heavy red line in Figure D-11. The Low $CO_2$ (price) and Low Scenario cases used the 90% probability of exceedance prices (10% decile in Figure D-11). The High $CO_2$ (price) and High Scenario cases used the 10% probability of exceedance prices (90 percent decile in Figure D-11). The year-by-year values are provided in Table D-5.

### *Carbon Dioxide Emission Performance Standards*

California, Montana, Oregon and Washington have established $CO_2$ emission performance standards for new baseload generating plants. The intent of the Oregon and Washington standards is to limit the $CO_2$ production of new baseload facilities to that of a contemporary combined-cycle gas turbine power plant fuelled by natural gas (about 830 lb$CO_2$/MWh). The California standard is less restrictive, allowing production of 1100 lb$CO_2$/MWh - a level that would allow baseload operation of many of the simple-cycle aeroderivative gas turbines installed in that state and require sequestration of about 50% of the $CO_2$ production of a coal-fired plant. Although the 1100 lb$CO_2$/MWh California standard was adopted by Washington as the initial standard, it seems likely that the Washington standard will be reduced in administrative review to a level approximating 830 lb$CO_2$/MWh, as the legislation clearly states that the standard is intended to represent the average rate of emissions of new natural gas combined-cycle plants. The Montana standard does not set an explicit carbon dioxide production limit, but rather mandates capture and sequestration of 50 percent of the carbon dioxide production of any new coal-fired generating facility, subject to approval of the state Public Service Commission. Additionally, Idaho has established an indefinite moratorium on coal-fired power plant development and the BC Energy Plan requires any new interconnected fossil fuel generation in the province to have zero net greenhouse gas emissions.

Development of specific resource types within given load-resource areas is controlled through the New Resource data input table as noted in Table D-2. Imports of power, however, from specific types of resources within other load-resource areas cannot be easily controlled in AURORA$^{xmp}$ because contractual paths are not modeled. In the development of the draft forecast, the BC Energy Plan restriction was approximated in by limiting new coal-fired resource options within the BC load-resource area to integrated gasification combined-cycle (IGCC) plants with $CO_2$ separation and sequestration (CSS). The state performance standards were approximated by limiting new coal-fired resource options within the California, Oregon, and Washington load-resource areas to IGCC plants with $CO_2$ separation and sequestration and by constraining new conventional coal resource options in peripheral areas to amounts sufficient only to meet native load. In addition, new coal plants were precluded in Idaho because of the moratorium on conventional coal development in that state. The Montana policy that new coal plants capture and sequester 50 percent of $CO_2$ emissions was not incorporated in this study.

Though initial runs of cases favoring coal showed some development of coal-steam units in several load-resource areas not subject to performance standards, no IGCC units with CSS were developed, probably because of the high cost of these plants relative to other options. The IGCC option was subsequently removed to expedite later runs. Furthermore, because development of coal-steam units in cases favoring coal in areas peripheral to areas having restrictions on coal generation did not exceed load growth of the peripheral areas, coal-steam units were therefore retained as a new resource option in these areas.

## THE BASE CASE FORECAST

### *Resource Build-out and Load-resource Balances*

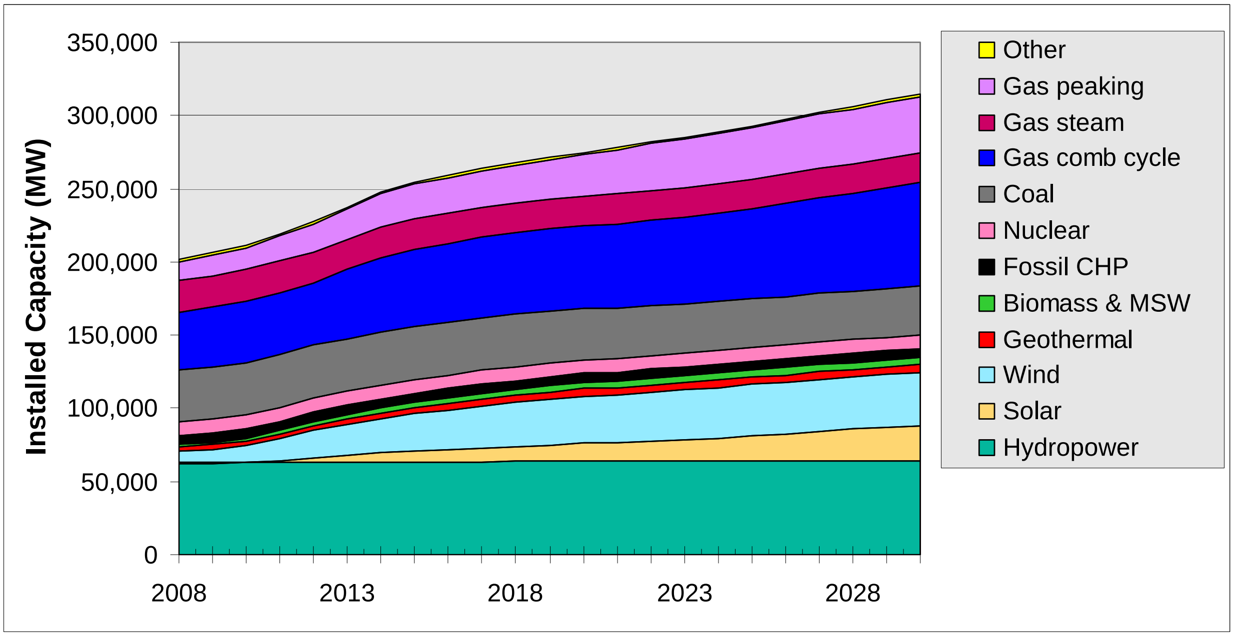
The first step in preparing a forecast using AURORA$^{xmp}$ is to run a long-term system expansion study to develop an economically optimal mix of resources to serve the forecasted load and maintain reserve margins. Each year of the study period, AURORA$^{xmp}$ tests the economic viability of each existing resource by calculating its levelized present value based on forward costs and revenues. Resources not meeting a minimum present value criterion for retirement (Set at $10,000/MW net loss for these forecasts) are retired. Likewise, the potential economic viability of available new resource options are tested and those meeting a net present value hurdle (Set at $10,000/MW net revenue for these forecasts) are added. The system expansion runs are repeated with incremental changes to the resource mix until the present value system price stabilizes. This typically requires 35 to 70 iterations.

The Base case forecast capacity build-out was developed through an incremental process of updating the forecast developed for the draft plan. This principal updates included the following:

- Update AURORAxmp to Version 9.6.1011.
- Update forecast of general inflation
- Update $CO_2$ price forecast
- Update forced and scheduled outage rates
- Update inventory of WECC generating resources
- Update the natural gas price forecast
- Update the base year loads and load growth forecasts
- Update the forecast of RPS resource development
- Incorporate representative hourly output for wind and solar resources
- Update new resource costs using revised discount rates and financing costs

The resulting WECC installed capacity by resource type is shown in Figure D-12. The expansion of solar, wind, geothermal and biomass capacity is largely a result of RPS resource development, augmented in the latter portion of the forecast period by economic development of discretionary solar thermal and wind. Economically-driven additions of combined-cycle and peaking gas turbines are also evident. Discretionary resource additions in the Northwest consist of 570 megawatts of peaking gas turbines.

**Figure D-12: WECC Capacity Expansion - Base Case**




Not as evident at the scale of the chart are economic retirements of coal, gas-steam and older combined-cycle capacity. Northwest economic retirements include 2,540 megawatts of coal steam units and 1,600 megawatts of older, less-efficient combined-cycle units.

Firm capacity balances for the base case are shown in Figure D-13. WECC reserve margins are maintained largely through addition of gas combined-cycle and gas peaking units (Figure D-12), with smaller contributions from RPS hydro, geothermal, biomass and solar capacity additions. The Northwest reserve margin remains stable at current levels through 2019 and then begins to decline to adequacy standard levels as coal units are retired. Periodic additions of gas peaking units help maintain Northwest reserves.

Energy load-resource balances for the base case are shown in Figure D-14. RPS resource additions and economic development of combined-cycle and gas peaking capacity maintain ample firm energy balances throughout the forecast period for WECC as a whole. In the Northwest, low load growth net of conservation, RPS resource additions and economic development of gas peaking capacity maintain adequate energy reserves even with retirement of coal and older gas units.

**Figure D-13: Firm Capacity Balance - Base Case**

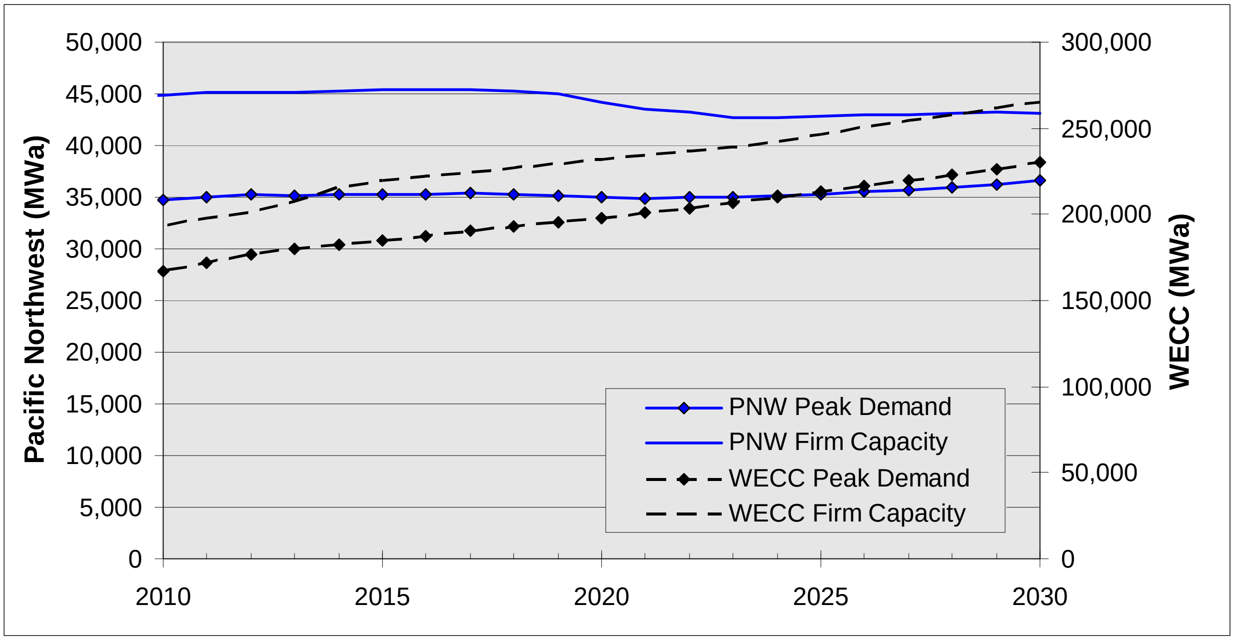
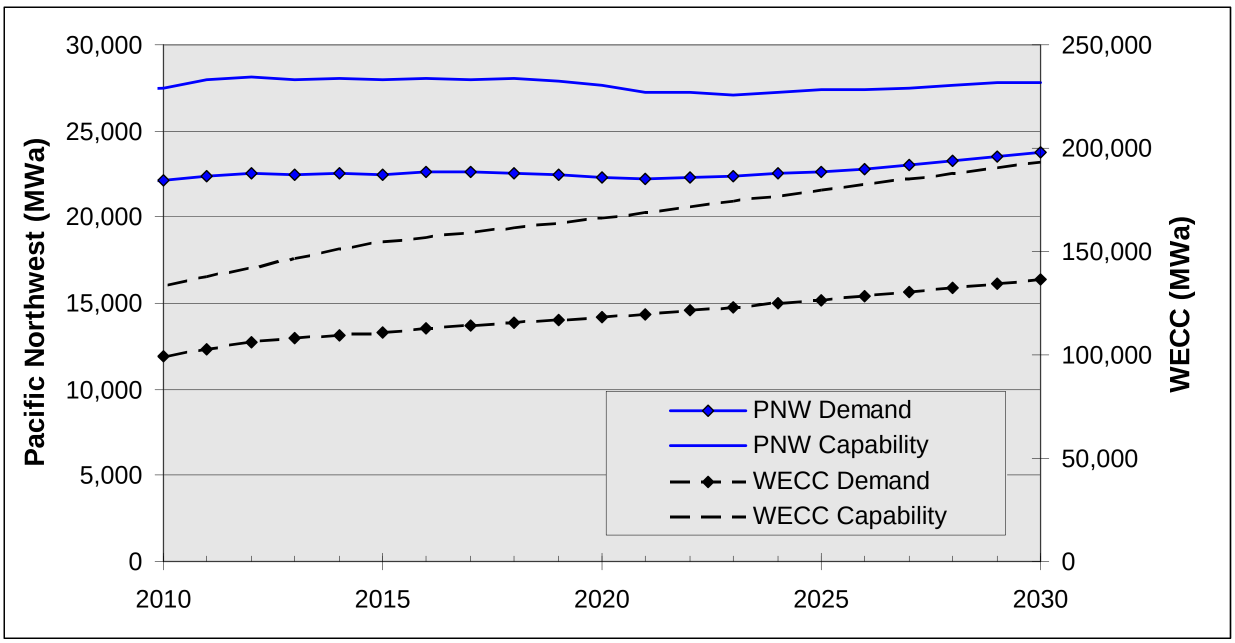


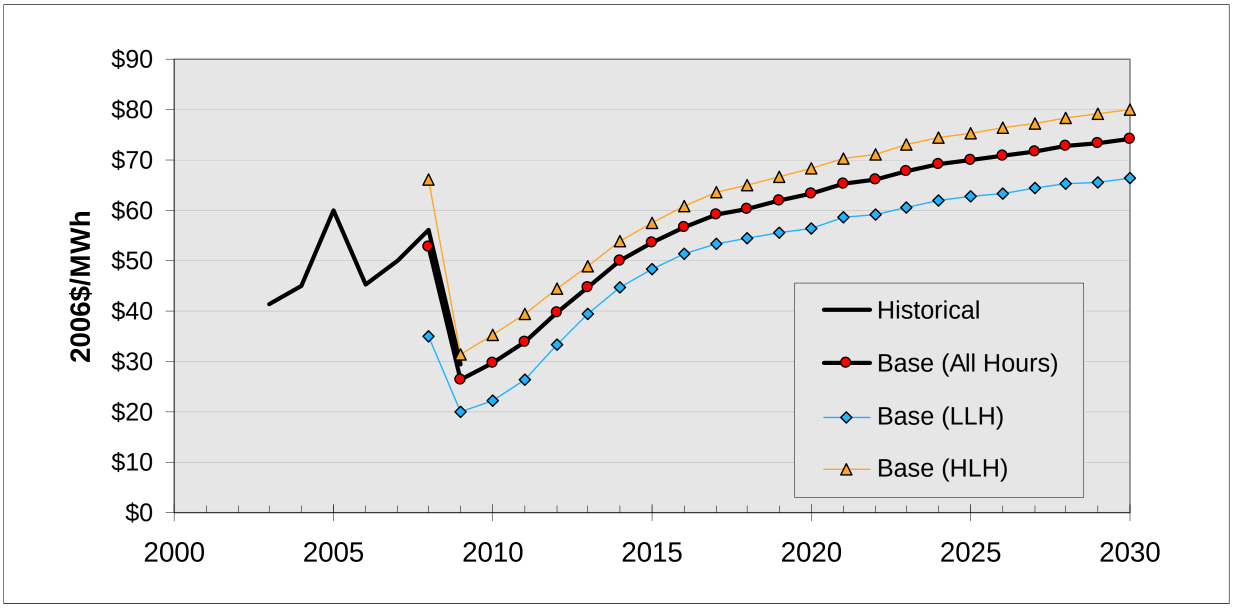

**Figure D-14: Energy Load-resource Balance - Base case**




## *Base Case Price Forecast*

The Council's forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2010 through 2029, is $55.50 per megawatt-hour (in year 2006 dollars). Figure D-15 shows recent historical annual average prices and the base case forecast for the Mid-Columbia trading hub. In addition to annual average "all-hour" values, annual average light-load hour and heavy load hour prices are also shown[7]. The 2008 and 2009 historical and forecast average annual prices are well correlated. The values underlying the curves are provided in Table D-6.

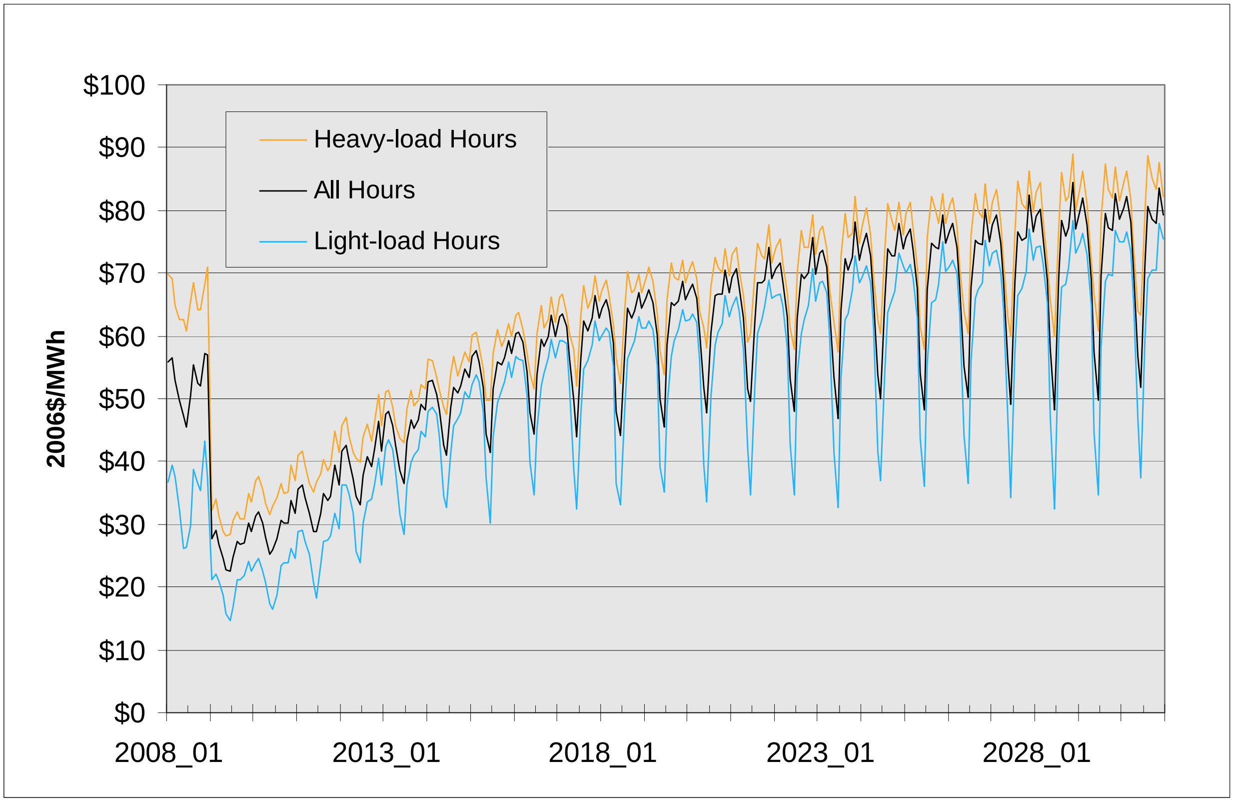
**Figure D-15: Annual Average Mid-Columbia Wholesale Power Price Forecast - Base Case**




Northwest electricity prices exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure D-16 shows the monthly average heavy-load hours, all hours, and light-load hours prices for the Base forecast. A flattening of light load hour prices during high-runoff, lower load seasons, becomes evident in the mid-term of the forecast period. This is likely attributable to the increasing penetration of low-variable cost, must-run resources. The monthly average prices for the base case forecast are provided in Table D-8.

[7] Heavy load hours are comprised of weekday and Saturday hours 7 through 22.

**Figure D-16: Monthly Average Mid-Columbia Wholesale Power Price Forecast - Base Case**




# SENSITIVITY CASES

Four sensitivity studies and two bounding scenario cases were run. All cases assume 95% achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation, as assumed for the base case forecast. The changing case assumptions are as follows:

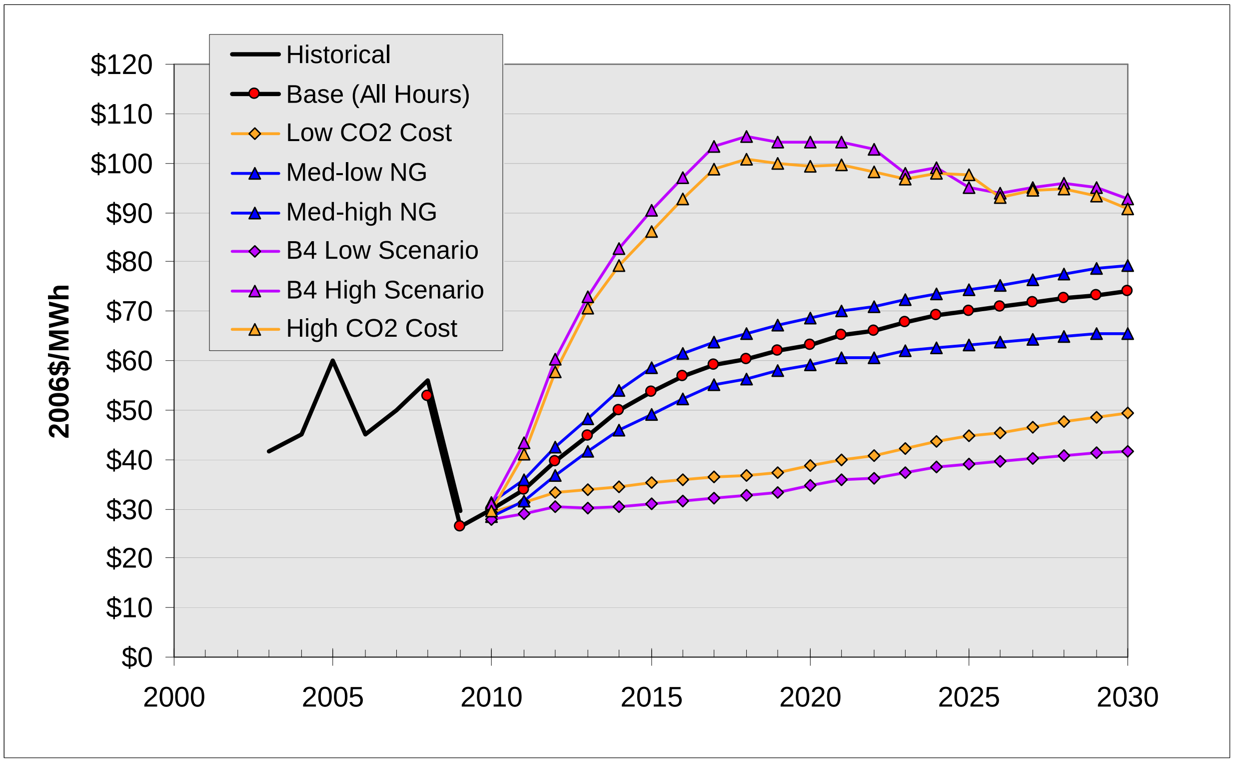
| Case | Fuel Prices | $CO_2$ Cost |
|---|---|---|
| **Base** | Medium Case | Mean of RPM $0 -100 case[8] |
| **Low $CO_2$ Cost** | Medium Case | 90% prob. of exceedance decile |
| **High $CO_2$ Cost** | Medium Case | 10% prob. of exceedance decile |
| **Medium-Low Natural Gas** | Medium-low NG | Mean of RPM $0 -100 case |
| **Medium-High Natural Gas** | Medium-high NG | Mean of RPM $0 -100 case |
| **Low Scenario** | Medium-low NG | 90% prob. of exceedance decile |
| **High Scenario** | Medium-high NG | 10% prob. of exceedance decile |

A capacity expansion study was run for each sensitivity case to simulate economically optimal resource development if the fuel and $CO_2$ price assumptions of the sensitivity cases held throughout the forecast period.

[8] See Chapter 10.

The results of the sensitivity cases are compared to the Base case and to historical power prices in Figure D-17. Comparing the shape of the power price forecasts with $CO_2$ price forecast of Figure D-11 clearly demonstrates the significant effect of $CO_2$ costs on prices. This is particularly evident in the High $CO_2$ and High Scenario cases. In these cases, prices rise rapidly early in the forecast period as $CO_2$ prices increase, then stabilize and decline as $CO_2$ prices reach a steady-state of $100/ton $CO_2$ and additional low carbon resources are deployed.

**Figure D-17: Annual Average Mid-Columbia Wholesale Power Price Forecast - Sensitivity Cases**




The apparent extreme sensitivity of the results to $CO_2$ prices compared to natural gas prices is somewhat misleading. The range of the $CO_2$ price forecast is much greater than that of the natural gas price forecasts used in the sensitivity studies. This reflects the considerable uncertainty regarding future $CO_2$ prices.

The results of the two cases incorporating high $CO_2$ costs also illustrate the ability to adapt to persistently high $CO_2$ costs. Prices in these cases rise rapidly in response to $CO_2$ prices, but then decline as more costly coal units and older, less efficient natural gas units are replaced by more efficient gas combined-cycle units and renewables. Greater response to $CO_2$ costs than shown here is possible. Load growth is fixed in these studies rising prices could be expected to induce additional energy efficiency improvements, further reducing power prices.

# AVOIDED RESOURCE COST

The Council's wholesale power price forecast has been used by others as a measure of avoided resource cost. The Council cautions that this price forecast may not be a suitable stand-alone measure of avoided resource costs. The Northwest as a whole enters the forecast period with an energy surplus, and remains so throughout the period because of the addition of resources to meet renewable resource portfolio requirements. Because no discretionary (non-RPS) energy resources are added, the resulting energy prices do not reflect the avoided cost of any new resource. The actual avoided resource costs for the three Northwest states with renewable portfolio standards are the costs of the renewable resources needed to meet RPS requirements, or any capacity additions needed to supply balancing reserves (balancing reserve requirements are not tracked in the AURORA$^{xmp®}$ model). Individual states in the region may have specific requirements, such as PURPA (Public Utilities Regulatory Policies Act) determinations, that are governed by state or federal law or regulations; the Council's recommendations on avoided cost are not intended to supplant those requirements. About 570 megawatts of simple-cycle gas turbines are added in the southern Idaho area to maintain capacity reserves. But because this capacity only contributes incidental energy, even the energy price forecast for the southern Idaho area does not represent an avoided resource cost. The forecast energy market prices can be adjusted to represent avoided resource costs by use of price adders representing the risk premium and capacity value of the specific resource being evaluated. The resulting sum of energy market prices, capacity credit and risk premium represents the avoided cost of the resource in question. This is the approach taken in the Council's planning to establish the value of energy efficiency measures.

# NATURAL GAS CONSUMPTION

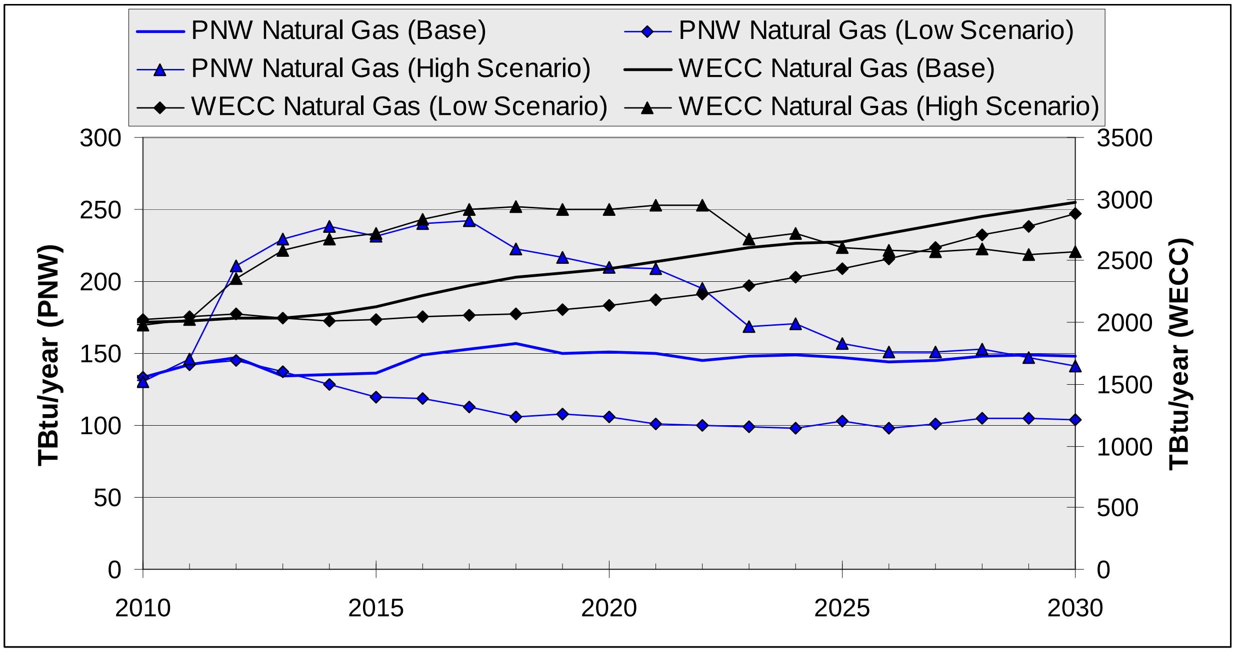
Extensive construction of gas-fired combined-cycle capacity has greatly increased the use of natural gas for power generation in the Western United States since the early 1990s. In the Northwest, gas-fired capacity increased from 1,550 megawatts, representing about 3 percent of regional capacity, to over 9,000 megawatts in 2009, representing 16 percent of regional capacity. This development has been motivated by the introduction of reliable, low emission, high efficiency combined-cycle gas turbine power plants, and generally attractive natural gas prices (despite several relatively short term peaks). This forecast suggests that natural gas-fired plants will continue to supersede coal units as the primary thermal component of the power system. This raises the issue of future gas supply, transportation and storage adequacy. Over the past two decades, increased use of natural gas for power generation has been offset by reduction in industrial demand for gas; however, it is not clear that additional offset can be expected from this source.

Annual natural gas consumption for the Base, High Scenario and Low Scenario cases is shown in Figure D-18. Northwest consumption (blue lines) is plotted against the left-hand axis and WECC consumption (black lines) is plotted against the right-hand axis. The Base case results show consumption for WECC as a whole rising about 43 percent from 2010 through 2030, as natural gas substitutes for coal in response to rising $CO_2$ prices. The Base case Northwest consumption, however, is nearly flat over the same period, despite retirement of over 2500 megawatts of coal capacity and rising $CO_2$ prices. Examination of resource dispatch and interzonal transfers in the base case show substantial reduction in net power exports from the Northwest during this period. It appears that construction of new gas combined-cycle units outside of the Northwest (28,000 megawatts of new combined-cycle units are constructed in the Base case - all outside of the Northwest) for purposes of capacity and energy results in reduction of net Northwest exports, allowing the Northwest to maintain energy adequacy without increasing natural gas use.

The Low Scenario shows reduction of natural gas use in the Northwest - probably a result of low load growth (net of conservation), continued coal use, and the additional energy of RPS resources. WECC-wide gas use increases nearly at the same rate as in the Base case. This appears to be due to more rapid rates of load growth outside the Northwest and construction of new gas combined-cycle units in response to low natural gas prices (33,000 megawatts of new combined-cycle units are constructed in the Low Scenario - again all outside of the Northwest).

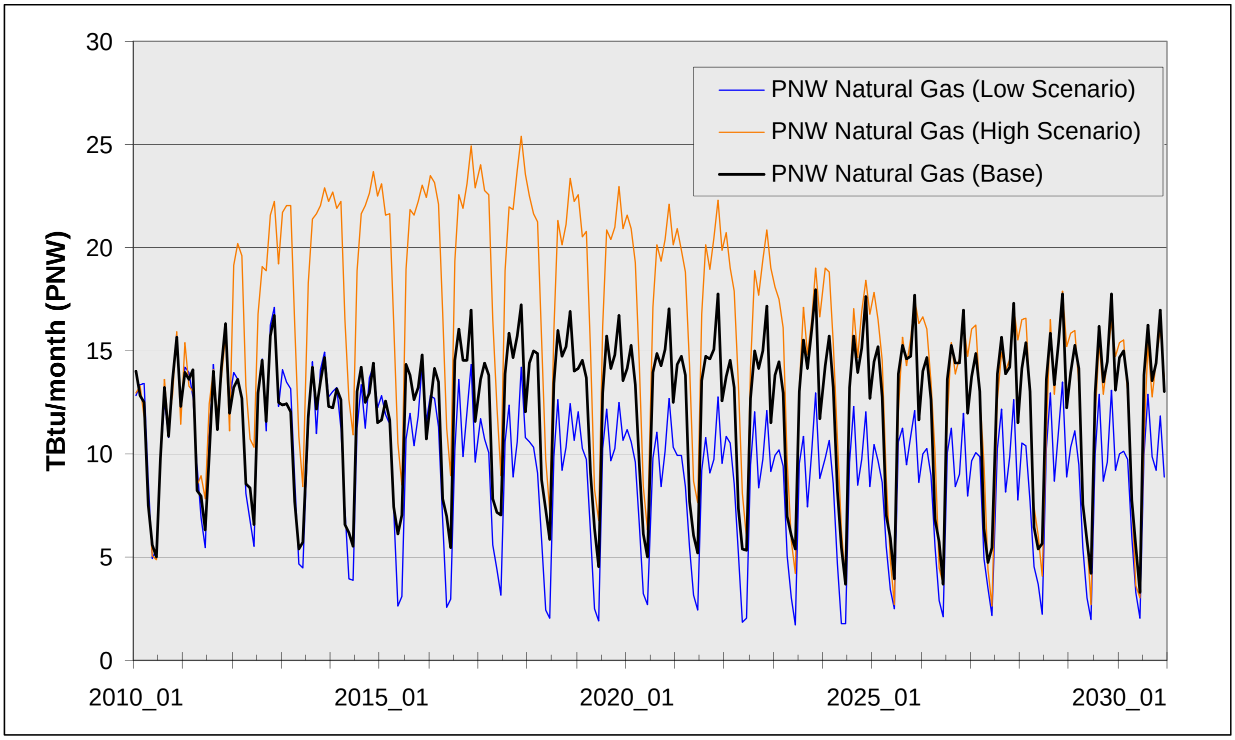
The High Scenario shows rapidly increasing natural gas consumption in the near- to mid-term as $CO_2$ prices increase - both for the Northwest as well as for WECC as a whole - as dispatch shifts from coal to combined-cycle units. In the longer-term, Northwest gas consumption for power generation returns to 2010 levels as gas combined-cycle units and discretionary renewable resources are constructed outside the Northwest. This allows the Northwest to reduce net exports and retire coal units, yet serve native loads while reducing natural gas usage. Accelerated construction of discretionary renewable resources throughout WECC results in declining gas consumption in the long-term.

**Figure D-18: Forecast Annual Natural Gas Consumption for Power Generation**




The seasonal pattern of natural gas use affects the configuration of the gas supply system. Even if annual gas demand remains fairly constant, increasing seasonal volatility may require storage capacity to be expanded. Figure D-19 illustrates monthly patterns of natural gas consumption in the Northwest, for the Base, Low Scenario and the High Scenario cases. Seasonal minimums decline in all cases, as a likely result of the increasing penetration of low variable cost RPS resources. These will reduce operation of gas-fired units during the low-load, high-runoff spring months. Seasonal maximums remain fairly constant in the Base case and decline somewhat in the Low Scenario. Seasonal maximums increase rapidly in the near- to mid-term in the High Scenario as dispatch shifts from coal to combined-cycle units, then fall off as Northwest exports decline as a result of capacity additions outside of the Northwest. It is not known whether the existing gas supply system could support the increase in seasonal maxima of the High Scenario case.

**Figure D-19: Forecast Northwest Monthly Natural Gas Consumption for Power Generation**




# CARBON DIOXIDE PRODCTION

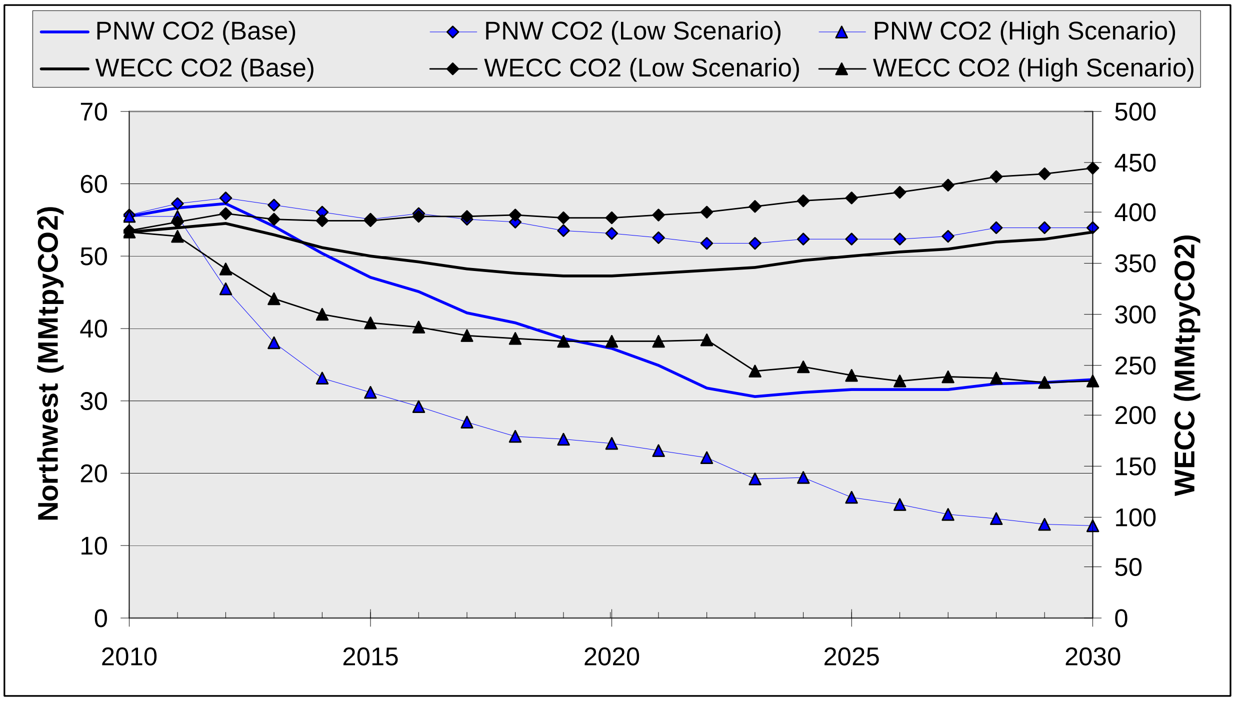
The annual $CO_2$ production for the Base, Low Scenario and High Scenario cases is shown in Figure D-20. Northwest $CO_2$ production consistent with Oregon and Washington policy goals is about 35 million tons per year of CO2 (MMtpy) by 2030 and continued reduction through 2050 ("geographic basis" as used in the Council's 2007 $CO_2$ Footprint study). This is about 60 percent of expected 2010 levels under average water conditions. The equivalent level for WECC as a whole is about 235 MMtpy.

In the base case, Northwest $CO_2$ production declines to 35 MMtpy by 2021, but commences to rise slowly in 2024, though remaining below 35 MMtpy in 2030. WECC as a whole in the base case, however, declines only to 337 MMtpy by 2019 and rises thereafter to 2010 levels by 2030, well above proposed greenhouse gas target levels.

The High Scenario $CO_2$ price assumptions are far more effective in reducing $CO_2$ production, even though natural gas prices are greater in this scenario. Northwest production declines rapidly through the entire period, achieving about 13 MMtpy by 2030, well below target levels. WECC $CO_2$ production as a whole declines fairly steadily through the period, reaching 60 percent of 2010 levels (234 MMtpy) by 2030.

The Low Scenario results in slowly increasing $CO_2$ production for WECC as a whole and fairly stable production for the Northwest. The Medium-Low natural gas prices of this scenario and continued acquisition of RPS resources are likely responsible for the low WECC-wide increase in $CO_2$ production even in the absence of significant $CO_2$ prices.

**Figure D-20: Forecast Annual $CO_2$ Production from Power Generation**



# TABULAR DATA

**Table D-1: Forecasted Energy Loads for the Load-resource Areas**

| | AB | AZ | BC | Baja N. | CA N. | CA S. | CO | ID S. | MT E. | NM | NV N. | NV S. | PNWE | PNWW | UT | WY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2008** | 8413 | 9380 | 7141 | 1195 | 14914 | 18647 | 6077 | 2596 | 1028 | 2362 | 1384 | 2944 | 2362 | 5357 | 13960 | 2732 |
| **2009** | 8332 | 9293 | 6893 | 1170 | 14536 | 18245 | 6042 | 2367 | 945 | 2412 | 1298 | 2865 | 2412 | 5152 | 13493 | 2741 |
| **2010** | 8596 | 9591 | 6931 | 1194 | 14572 | 18595 | 6257 | 2420 | 901 | 2565 | 1269 | 2905 | 2565 | 5175 | 13615 | 2866 |
| **2011** | 9051 | 10102 | 7113 | 1243 | 14729 | 19343 | 6613 | 2485 | 892 | 2785 | 1265 | 3006 | 2785 | 5220 | 13743 | 3058 |
| **2012** | 9530 | 10640 | 7300 | 1294 | 15007 | 20121 | 6989 | 2501 | 874 | 3023 | 1262 | 3111 | 3023 | 5268 | 13899 | 3263 |
| **2013** | 10009 | 10904 | 7379 | 1320 | 15210 | 20370 | 7128 | 2495 | 863 | 3090 | 1275 | 3185 | 3090 | 5240 | 13844 | 3345 |
| **2014** | 10514 | 11197 | 7399 | 1347 | 15340 | 20622 | 7253 | 2509 | 863 | 3152 | 1274 | 3255 | 3152 | 5258 | 13905 | 3431 |
| **2015** | 11010 | 11496 | 7289 | 1374 | 15465 | 20875 | 7376 | 2512 | 854 | 3229 | 1289 | 3330 | 3229 | 5245 | 13886 | 3508 |
| **2016** | 11471 | 11796 | 7273 | 1401 | 15596 | 21109 | 7523 | 2525 | 857 | 3283 | 1309 | 3416 | 3283 | 5275 | 13961 | 3587 |
| **2017** | 11854 | 12113 | 7263 | 1429 | 15745 | 21339 | 7662 | 2532 | 854 | 3341 | 1321 | 3484 | 3341 | 5272 | 13949 | 3643 |
| **2018** | 12189 | 12422 | 7256 | 1458 | 15883 | 21580 | 7808 | 2530 | 852 | 3399 | 1343 | 3575 | 3399 | 5266 | 13930 | 3713 |
| **2019** | 12507 | 12736 | 7248 | 1486 | 16021 | 21698 | 7950 | 2505 | 843 | 3458 | 1358 | 3651 | 3458 | 5243 | 13883 | 3772 |
| **2020** | 12949 | 13040 | 7218 | 1518 | 16167 | 21919 | 8097 | 2481 | 836 | 3505 | 1375 | 3736 | 3505 | 5210 | 13792 | 3844 |
| **2021** | 13376 | 13334 | 7204 | 1551 | 16311 | 22134 | 8249 | 2482 | 835 | 3543 | 1393 | 3823 | 3543 | 5194 | 13742 | 3915 |
| **2022** | 13793 | 13664 | 7190 | 1583 | 16458 | 22345 | 8403 | 2501 | 837 | 3598 | 1410 | 3910 | 3598 | 5206 | 13769 | 3984 |
| **2023** | 14217 | 13998 | 7175 | 1615 | 16605 | 22552 | 8559 | 2523 | 839 | 3651 | 1429 | 4001 | 3651 | 5222 | 13808 | 4056 |
| **2024** | 14662 | 14336 | 7159 | 1648 | 16753 | 22752 | 8718 | 2555 | 845 | 3704 | 1447 | 4092 | 3704 | 5260 | 13905 | 4129 |
| **2025** | 15136 | 14680 | 7142 | 1683 | 16903 | 22968 | 8880 | 2579 | 849 | 3755 | 1465 | 4186 | 3755 | 5276 | 13945 | 4204 |
| **2026** | 15615 | 15032 | 7126 | 1718 | 17055 | 23184 | 9046 | 2610 | 854 | 3807 | 1484 | 4283 | 3807 | 5310 | 14031 | 4280 |
| **2027** | 16107 | 15397 | 7111 | 1754 | 17207 | 23400 | 9214 | 2646 | 860 | 3863 | 1503 | 4381 | 3863 | 5353 | 14139 | 4357 |
| **2028** | 16614 | 15769 | 7095 | 1790 | 17361 | 23617 | 9385 | 2695 | 871 | 3918 | 1522 | 4482 | 3918 | 5422 | 14317 | 4435 |
| **2029** | 17140 | 16149 | 7080 | 1827 | 17517 | 23836 | 9560 | 2731 | 876 | 3973 | 1541 | 4585 | 3973 | 5462 | 14420 | 4515 |
| **2030** | 17683 | 16538 | 7064 | 1865 | 17674 | 24059 | 9738 | 2776 | 885 | 4030 | 1561 | 4691 | 4030 | 5521 | 14573 | 4597 |

**Table D-2: New Resource Options**

| | Capacity (MW) | Earliest Service | Note |
|---|---|---|---|
| **Gas Combined-cycle** | 415 | 2013 | |
| **Aeroderivative GT** | 2 x 45 | 2011 | |
| **Wind** | 100 | 2011 | |
| **MT Wind > PNW (Via Colstrip Transmission Upgrade)** | 659 | 2015 | Capacity limited by CTS upgrade potential |
| **MT Wind > PNW (New transmission via S. ID)** | 570 | 2015 | |
| **Advanced Nuclear** | 1100 | 2023 | |
| **Solar (Parabolic trough)** | 200 | 2013 | AZ, CA, CO, NM, NV & UT areas only |
| **Coal-steam (Supercritical, no CCS)** | 400 | 2017 | n/a in BC, CA, ID, MT, OR or WA areas because of policy restrictions |
| **Coal gasification (with 88% CSS)** | 520 | Uncertain | Tested but not selected in the draft forecast, removed for the final forecast because of uncertain availability of sequestration |
| **Solar Photovoltaics** | 5 x 20 MW | 2012 | Utility-scale plants |

**Table D-3: State Renewable Portfolio Standards (September 2009)**

| | Qualifying Generating Resource Types | Existing Resource Vintage Eligibility | Applicable Providers | Ultimate Target (%sales) |
|---|---|---|---|---|
| **Arizona** | Solar, Landfill gas, Wind, Biomass, Hydro, Geothermal, CHP | Jan 1997 | IOUs, Coops, Retail Providers | 15% by 2025 |
| **California** | Biomass, Geothermal, MSW, Anaerobic digestion, Small hydro, Tidal, Wave, Ocean Thermal, Biodiesel | Sep 1996 + earlier QF & SPPs | All providers[9] | 33% by 2020[10] |
| **Colorado** | Solar, Wind, Geothermal, Biomass, Small hydro, bottoming cycle CHP | Not specified | IOU's, larger coops and munis | IOUS: 20% by 2020<br>Coops & munis: 10% by 2020 |
| **Montana** | Solar, Landfill Gas, Wind, Biomass, Hydro (10 MW or less), Geothermal, Anaerobic digestion | Jan 2005 | IOU's, retail suppliers | 15% by 2015 |
| **New Mexico** | Solar, Wind, Landfill, Biomass, Hydro, Geothermal, "Zero emission technology", Anaerobic digestion | No limit except hydro (July 2007, or later) | IOU's, certain coops | IOUs: 20% by 2020<br>Coops: 10% by 2020 |
| **Nevada** | Energy-efficiency, Solar, Landfill gas, Wind, Biomass, Certain hydro, Geothermal, MSW, Tires | No limit | IOU's, retail suppliers | 25% by 2025 |
| **Oregon** | Existing low-impact hydro (50 aMW max per utility); new hydro, wind, solar, ocean, geothermal, non-contaminated biomass | Jan 1995 with exceptions | All | Large: 25% by 2025<br>Medium: 10% by 2025<br>Small: 5% by 2025 |
| **Washington** | Solar, landfill gas, wind, biomass, hydro efficiency improvements and conduit projects, geothermal, anaerobic digestion, tidal, wave, ocean thermal and biodiesel | March 31, 1999 | Utilities serving more than 25,000 customers | 15% by 2020 |

[9] Mandated for publically-owned utilities by Executive Order S-21-09 of September 15, 2009.
[10] The California RPS was increased to 33% by 2020 by Executive Order S-21-09 of September 15, 2009.

**Table D-4: Estimated Committed and Forecast Incremental RPS Energy Requirements (average megawatts, 100% achievement)**

| | AZ | BC | CA (33%) | CO | MT | NM | NV11 | OR | WA |
|---|---|---|---|---|---|---|---|---|---|
| **Committed** | 87 | 366 | 3954 | 454 | 6512 | 111 | 273 | 465 | 520 |
| **Cumulative new (100% achievement of standards)** | | | | | | | | | |
| **2010** | 32 | 0 | 425 | 0 | 0 | 0 | 21 | 0 | 0 |
| **2011** | 77 | 0 | 1068 | 0 | 0 | 0 | 63 | 0 | 0 |
| **2012** | 115 | 0 | 1774 | 0 | 19 | 0 | 137 | 0 | 0 |
| **2013** | 157 | 0 | 2416 | 0 | 24 | 112 | 277 | 0 | 0 |
| **2014** | 196 | 17 | 2863 | 280 | 31 | 147 | 339 | 0 | 218 |
| **2015** | 240 | 85 | 3329 | 368 | 37 | 184 | 452 | 0 | 367 |
| **2016** | 313 | 136 | 3401 | 450 | 37 | 214 | 463 | 0 | 511 |
| **2017** | 390 | 185 | 3477 | 537 | 37 | 243 | 496 | 0 | 662 |
| **2018** | 471 | 239 | 3551 | 626 | 37 | 273 | 508 | 0 | 812 |
| **2019** | 555 | 296 | 3602 | 718 | 37 | 304 | 524 | 0 | 958 |
| **2020** | 642 | 351 | 3674 | 813 | 37 | 335 | 537 | 0 | 953 |
| **2021** | 733 | 406 | 3745 | 836 | 37 | 341 | 551 | 0 | 941 |
| **2022** | 826 | 462 | 3816 | 860 | 37 | 346 | 566 | 478 | 939 |
| **2023** | 925 | 520 | 3885 | 885 | 37 | 353 | 580 | 538 | 939 |
| **2024** | 1027 | 579 | 3954 | 910 | 37 | 359 | 595 | 599 | 941 |
| **2025** | 1134 | 638 | 4026 | 935 | 38 | 366 | 610 | 662 | 944 |
| **2026** | 1163 | 698 | 4099 | 961 | 38 | 372 | 626 | 670 | 950 |
| **2027** | 1192 | 758 | 4171 | 987 | 39 | 379 | 641 | 677 | 956 |
| **2028** | 1223 | 819 | 4244 | 1014 | 39 | 385 | 657 | 685 | 965 |
| **2029** | 1254 | 882 | 4318 | 1041 | 40 | 392 | 672 | 697 | 977 |
| **Total** | 1341 | 1248 | 8272 | 1495 | 105 | 503 | 945 | 1162 | 1497 |

[11] Nevada values are based on the earlier ultimate target of 20% by 2015.
[12] Overestimate, should be 51MWa. Includes 14 MWa of existing resources that entered service prior to January 2005.

**Table D-5: Forecast Carbon Dioxide Prices (2006$/tonCO2)**

| | Mean of $0 - 100 portfolio Risk analysis | 90% Probability of Exceedance (10% decile) | 10% Probability of Exceedance (90% decile) |
|---|---|---|---|
| **2010** | $0.43 | $0.00 | $0.00 |
| **2011** | $3.83 | $0.00 | $15.66 |
| **2012** | $10.31 | $0.00 | $37.33 |
| **2013** | $17.87 | $0.00 | $54.67 |
| **2014** | $24.55 | $0.00 | $67.02 |
| **2015** | $29.29 | $0.00 | $77.54 |
| **2016** | $33.53 | $0.00 | $86.84 |
| **2017** | $37.11 | $0.00 | $96.83 |
| **2018** | $39.51 | $0.06 | $100.00 |
| **2019** | $41.16 | $1.19 | $100.00 |
| **2020** | $42.50 | $2.27 | $100.00 |
| **2021** | $43.41 | $2.97 | $100.00 |
| **2022** | $44.26 | $3.67 | $100.00 |
| **2023** | $45.20 | $4.45 | $100.00 |
| **2024** | $45.88 | $4.94 | $100.00 |
| **2025** | $46.27 | $5.16 | $100.00 |
| **2026** | $46.71 | $5.49 | $100.00 |
| **2027** | $47.11 | $5.88 | $100.00 |
| **2028** | $47.34 | $5.96 | $100.00 |
| **2029** | $47.64 | $5.96 | $100.00 |
| **2030** | $47.64 | $5.96 | $100.00 |

**Table D-6: Annual Average Mid-Columbia Wholesale Power Prices - Base Case Forecast (2006$/MWh)**

| | On-peak | Off-peak | All Hours |
|---|---|---|---|
| **2010** | $35 | $22 | $30 |
| **2011** | $39 | $26 | $34 |
| **2012** | $45 | $33 | $40 |
| **2013** | $49 | $39 | $45 |
| **2014** | $54 | $45 | $50 |
| **2015** | $58 | $48 | $54 |
| **2016** | $61 | $51 | $57 |
| **2017** | $64 | $53 | $59 |
| **2018** | $65 | $54 | $60 |
| **2019** | $67 | $56 | $62 |
| **2020** | $68 | $57 | $63 |
| **2021** | $70 | $59 | $65 |
| **2022** | $71 | $59 | $66 |
| **2023** | $73 | $61 | $68 |
| **2024** | $75 | $62 | $69 |
| **2025** | $75 | $63 | $70 |
| **2026** | $76 | $63 | $71 |
| **2027** | $77 | $64 | $72 |
| **2028** | $78 | $65 | $73 |
| **2029** | $79 | $65 | $73 |
| **2030** | $80 | $66 | $74 |

**Table D-7: Monthly Average Mid-Columbia Wholesale Power Prices - Base Case Forecast (2006$/MWh)**

| Month | Heavy Load Hours | Light Load Hours | All Hours | Month | Heavy Load Hours | Light Load Hours | All Hours |
|---|---|---|---|---|---|---|---|
| Jan-2010 | $37.03 | $23.87 | $31.23 | Jan-2015 | $60.08 | $52.16 | $56.76 |
| Feb-2010 | $37.54 | $24.62 | $32.00 | Feb-2015 | $60.60 | $53.93 | $57.74 |
| Mar-2010 | $35.65 | $22.57 | $30.16 | Mar-2015 | $58.24 | $52.62 | $55.76 |
| Apr-2010 | $33.30 | $20.70 | $27.98 | Apr-2015 | $54.71 | $48.00 | $51.88 |
| May-2010 | $31.43 | $17.43 | $25.26 | May-2015 | $49.77 | $37.33 | $44.29 |
| Jun-2010 | $32.82 | $16.41 | $25.89 | Jun-2015 | $49.81 | $30.17 | $41.52 |
| Jul-2010 | $34.27 | $18.70 | $27.74 | Jul-2015 | $57.21 | $43.87 | $51.61 |
| Aug-2010 | $36.41 | $23.51 | $30.72 | Aug-2015 | $61.08 | $49.26 | $55.87 |
| Sep-2010 | $34.95 | $23.79 | $30.24 | Sep-2015 | $58.44 | $51.46 | $55.49 |
| Oct-2010 | $35.06 | $23.81 | $30.10 | Oct-2015 | $59.36 | $52.62 | $56.53 |
| Nov-2010 | $39.52 | $26.16 | $33.88 | Nov-2015 | $61.98 | $55.81 | $59.24 |
| Dec-2010 | $36.85 | $24.51 | $31.68 | Dec-2015 | $59.86 | $53.47 | $57.18 |
| Jan-2011 | $40.88 | $28.93 | $35.61 | Jan-2016 | $63.19 | $56.68 | $60.32 |
| Feb-2011 | $41.58 | $29.16 | $36.26 | Feb-2016 | $63.83 | $56.22 | $60.59 |
| Mar-2011 | $39.36 | $27.19 | $34.26 | Mar-2016 | $60.98 | $56.13 | $58.94 |
| Apr-2011 | $36.55 | $25.17 | $31.75 | Apr-2016 | $57.18 | $50.47 | $54.35 |
| May-2011 | $35.07 | $20.72 | $28.74 | May-2016 | $54.05 | $39.90 | $47.81 |
| Jun-2011 | $36.67 | $18.16 | $28.85 | Jun-2016 | $51.62 | $34.59 | $44.43 |
| Jul-2011 | $38.05 | $23.67 | $31.71 | Jul-2016 | $60.41 | $45.33 | $53.76 |
| Aug-2011 | $40.36 | $27.30 | $34.88 | Aug-2016 | $64.97 | $51.95 | $59.51 |
| Sep-2011 | $38.43 | $27.44 | $33.79 | Sep-2016 | $61.27 | $54.07 | $58.23 |
| Oct-2011 | $39.38 | $28.15 | $34.43 | Oct-2016 | $62.54 | $56.43 | $59.85 |
| Nov-2011 | $44.77 | $31.86 | $39.32 | Nov-2016 | $66.21 | $59.35 | $63.31 |
| Dec-2011 | $41.45 | $29.25 | $36.33 | Dec-2016 | $62.26 | $56.54 | $59.86 |
| Jan-2012 | $45.76 | $36.30 | $41.59 | Jan-2017 | $66.27 | $59.13 | $63.12 |
| Feb-2012 | $47.07 | $36.22 | $42.46 | Feb-2017 | $66.64 | $59.23 | $63.46 |
| Mar-2012 | $44.17 | $35.02 | $40.33 | Mar-2017 | $63.44 | $58.74 | $61.47 |
| Apr-2012 | $41.42 | $31.82 | $37.15 | Apr-2017 | $60.32 | $51.94 | $56.59 |
| May-2012 | $40.61 | $25.68 | $34.35 | May-2017 | $57.86 | $38.73 | $49.84 |
| Jun-2012 | $39.82 | $23.91 | $33.10 | Jun-2017 | $52.13 | $32.53 | $43.85 |
| Jul-2012 | $43.93 | $30.18 | $37.87 | Jul-2017 | $63.18 | $47.53 | $56.28 |
| Aug-2012 | $45.99 | $33.51 | $40.75 | Aug-2017 | $67.95 | $54.72 | $62.40 |
| Sep-2012 | $43.33 | $34.04 | $39.20 | Sep-2017 | $64.45 | $56.00 | $60.88 |
| Oct-2012 | $46.07 | $36.16 | $41.91 | Oct-2017 | $66.16 | $58.52 | $62.79 |
| Nov-2012 | $50.63 | $40.51 | $46.36 | Nov-2017 | $69.53 | $62.28 | $66.47 |
| Dec-2012 | $45.81 | $36.29 | $41.61 | Dec-2017 | $65.45 | $59.30 | $62.74 |
| Jan-2013 | $51.18 | $42.23 | $47.43 | Jan-2018 | $67.31 | $60.17 | $64.32 |
| Feb-2013 | $51.39 | $43.56 | $48.04 | Feb-2018 | $69.01 | $61.33 | $65.72 |
| Mar-2013 | $48.56 | $41.90 | $45.62 | Mar-2018 | $66.55 | $60.48 | $64.01 |
| Apr-2013 | $45.73 | $38.26 | $42.58 | Apr-2018 | $61.68 | $55.24 | $58.82 |
| May-2013 | $43.62 | $31.59 | $38.57 | May-2018 | $56.49 | $36.40 | $48.06 |
| Jun-2013 | $42.94 | $28.45 | $36.50 | Jun-2018 | $52.42 | $33.00 | $44.22 |
| Jul-2013 | $48.33 | $36.27 | $43.27 | Jul-2018 | $64.03 | $48.01 | $56.97 |
| Aug-2013 | $51.46 | $39.92 | $46.62 | Aug-2018 | $70.33 | $56.27 | $64.43 |
| Sep-2013 | $48.86 | $40.98 | $45.36 | Sep-2018 | $66.87 | $58.00 | $62.93 |
| Oct-2013 | $49.86 | $41.95 | $46.54 | Oct-2018 | $67.31 | $59.18 | $63.90 |
| Nov-2013 | $52.34 | $44.86 | $49.18 | Nov-2018 | $69.76 | $63.16 | $66.97 |
| Dec-2013 | $51.48 | $43.99 | $48.18 | Dec-2018 | $66.90 | $61.29 | $64.42 |
| Jan-2014 | $56.23 | $48.05 | $52.80 | Jan-2019 | $69.21 | $61.35 | $65.92 |
| Feb-2014 | $56.08 | $48.76 | $52.94 | Feb-2019 | $70.97 | $62.46 | $67.32 |
| Mar-2014 | $53.29 | $47.49 | $50.74 | Mar-2019 | $68.68 | $61.03 | $65.31 |
| Apr-2014 | $51.33 | $44.02 | $48.24 | Apr-2019 | $63.53 | $55.35 | $60.08 |
| May-2014 | $48.55 | $34.47 | $42.64 | May-2019 | $57.68 | $39.13 | $49.90 |
| Jun-2014 | $47.62 | $32.69 | $40.98 | Jun-2019 | $53.90 | $35.12 | $45.55 |
| Jul-2014 | $53.98 | $41.37 | $48.69 | Jul-2019 | $65.78 | $48.55 | $58.55 |
| Aug-2014 | $56.66 | $45.69 | $51.82 | Aug-2019 | $71.72 | $56.71 | $65.42 |
| Sep-2014 | $53.65 | $46.88 | $50.79 | Sep-2019 | $69.42 | $55.15 | $62.09 |
| Oct-2014 | $55.28 | $47.74 | $52.12 | Oct-2019 | $68.85 | $55.26 | $62.24 |
| Nov-2014 | $57.53 | $51.05 | $54.65 | Nov-2019 | $71.99 | $55.37 | $62.39 |
| Dec-2014 | $55.75 | $49.91 | $53.30 | Dec-2019 | $68.40 | $55.48 | $62.54 |

| Month | Heavy Load Hours | Light Load Hours | All Hours | Month | Heavy Load Hours | Light Load Hours | All Hours |
|---|---|---|---|---|---|---|---|
| Jan-2020 | $70.64 | $62.70 | $67.31 | Jan-2025 | $79.56 | $70.15 | $75.62 |
| Feb-2020 | $71.90 | $63.42 | $68.30 | Feb-2025 | $81.34 | $71.36 | $77.06 |
| Mar-2020 | $69.04 | $62.17 | $66.01 | Mar-2025 | $77.01 | $69.21 | $73.57 |
| Apr-2020 | $64.03 | $56.00 | $60.64 | Apr-2025 | $70.87 | $62.86 | $67.49 |
| May-2020 | $61.37 | $39.42 | $51.69 | May-2025 | $61.44 | $43.65 | $53.98 |
| Jun-2020 | $58.08 | $33.57 | $47.73 | Jun-2025 | $57.81 | $35.95 | $48.09 |
| Jul-2020 | $68.00 | $50.48 | $60.65 | Jul-2025 | $75.64 | $55.60 | $67.23 |
| Aug-2020 | $72.63 | $58.56 | $66.43 | Aug-2025 | $82.11 | $65.37 | $74.73 |
| Sep-2020 | $71.01 | $60.50 | $66.57 | Sep-2025 | $80.01 | $65.82 | $74.02 |
| Oct-2020 | $70.02 | $62.03 | $66.67 | Oct-2025 | $77.98 | $68.23 | $73.89 |
| Nov-2020 | $73.77 | $66.41 | $70.50 | Nov-2025 | $82.62 | $74.94 | $79.21 |
| Dec-2020 | $69.70 | $63.14 | $66.95 | Dec-2025 | $78.01 | $70.38 | $74.81 |
| Jan-2021 | $72.98 | $64.67 | $69.32 | Jan-2026 | $80.82 | $71.28 | $76.82 |
| Feb-2021 | $74.00 | $66.14 | $70.63 | Feb-2026 | $82.08 | $72.14 | $77.82 |
| Mar-2021 | $70.59 | $64.06 | $67.85 | Mar-2026 | $77.45 | $70.04 | $74.18 |
| Apr-2021 | $66.52 | $57.89 | $62.87 | Apr-2026 | $70.98 | $63.52 | $67.83 |
| May-2021 | $58.94 | $42.40 | $51.65 | May-2026 | $63.89 | $44.26 | $55.23 |
| Jun-2021 | $60.40 | $34.78 | $49.58 | Jun-2026 | $60.46 | $36.38 | $50.29 |
| Jul-2021 | $69.79 | $51.86 | $62.27 | Jul-2026 | $76.12 | $56.02 | $67.69 |
| Aug-2021 | $74.87 | $60.46 | $68.52 | Aug-2026 | $82.75 | $65.92 | $75.33 |
| Sep-2021 | $72.74 | $62.63 | $68.47 | Sep-2026 | $80.06 | $67.36 | $74.70 |
| Oct-2021 | $72.28 | $64.58 | $68.88 | Oct-2026 | $78.90 | $68.36 | $74.48 |
| Nov-2021 | $77.67 | $69.00 | $74.01 | Nov-2026 | $84.20 | $75.31 | $80.25 |
| Dec-2021 | $71.56 | $65.92 | $69.19 | Dec-2026 | $77.85 | $71.15 | $75.04 |
| Jan-2022 | $74.08 | $66.35 | $70.68 | Jan-2027 | $81.23 | $73.26 | $77.72 |
| Feb-2022 | $75.43 | $66.72 | $71.70 | Feb-2027 | $83.44 | $73.61 | $79.23 |
| Mar-2022 | $71.36 | $64.64 | $68.54 | Mar-2027 | $78.14 | $70.10 | $74.77 |
| Apr-2022 | $66.89 | $58.08 | $63.17 | Apr-2027 | $71.87 | $64.49 | $68.75 |
| May-2022 | $61.24 | $42.76 | $53.10 | May-2027 | $63.12 | $46.86 | $55.95 |
| Jun-2022 | $57.88 | $34.58 | $48.04 | Jun-2027 | $59.99 | $34.25 | $49.12 |
| Jul-2022 | $69.96 | $53.78 | $62.83 | Jul-2027 | $76.32 | $57.34 | $68.36 |
| Aug-2022 | $76.75 | $60.43 | $69.91 | Aug-2027 | $84.59 | $66.39 | $76.56 |
| Sep-2022 | $74.06 | $62.67 | $69.25 | Sep-2027 | $81.07 | $67.47 | $75.33 |
| Oct-2022 | $74.12 | $64.79 | $70.01 | Oct-2027 | $80.16 | $70.20 | $75.77 |
| Nov-2022 | $79.24 | $70.65 | $75.61 | Nov-2027 | $86.26 | $77.00 | $82.35 |
| Dec-2022 | $72.92 | $65.53 | $69.82 | Dec-2027 | $79.66 | $72.05 | $76.47 |
| Jan-2023 | $76.88 | $68.57 | $73.21 | Jan-2028 | $82.92 | $74.03 | $79.00 |
| Feb-2023 | $77.53 | $68.73 | $73.76 | Feb-2028 | $84.48 | $74.27 | $80.13 |
| Mar-2023 | $73.79 | $66.91 | $70.90 | Mar-2028 | $78.45 | $71.33 | $75.46 |
| Apr-2023 | $67.26 | $59.66 | $63.88 | Apr-2028 | $71.79 | $65.28 | $68.89 |
| May-2023 | $62.20 | $41.40 | $53.48 | May-2028 | $65.77 | $47.27 | $58.02 |
| Jun-2023 | $57.37 | $32.56 | $46.90 | Jun-2028 | $59.82 | $32.53 | $48.30 |
| Jul-2023 | $72.73 | $53.43 | $64.22 | Jul-2028 | $76.97 | $59.33 | $69.19 |
| Aug-2023 | $79.51 | $62.52 | $72.38 | Aug-2028 | $86.02 | $67.69 | $78.33 |
| Sep-2023 | $75.72 | $63.52 | $70.57 | Sep-2028 | $81.55 | $68.26 | $75.94 |
| Oct-2023 | $76.44 | $67.40 | $72.46 | Oct-2028 | $82.30 | $70.98 | $77.31 |
| Nov-2023 | $82.26 | $72.80 | $78.26 | Nov-2028 | $88.89 | $78.48 | $84.49 |
| Dec-2023 | $74.81 | $68.49 | $72.02 | Dec-2028 | $79.97 | $73.24 | $77.00 |
| Jan-2024 | $77.58 | $69.35 | $74.13 | Jan-2029 | $83.56 | $74.84 | $79.90 |
| Feb-2024 | $80.30 | $71.12 | $76.39 | Feb-2029 | $86.19 | $76.25 | $81.93 |
| Mar-2024 | $76.20 | $68.48 | $72.79 | Mar-2029 | $81.10 | $72.87 | $77.65 |
| Apr-2024 | $69.36 | $61.59 | $66.08 | Apr-2029 | $72.08 | $64.95 | $68.91 |
| May-2024 | $62.66 | $41.75 | $53.89 | May-2029 | $66.62 | $44.52 | $57.35 |
| Jun-2024 | $60.42 | $37.00 | $50.01 | Jun-2029 | $60.84 | $34.65 | $49.78 |
| Jul-2024 | $73.85 | $54.56 | $65.76 | Jul-2029 | $78.50 | $58.25 | $69.57 |
| Aug-2024 | $81.15 | $63.73 | $73.85 | Aug-2029 | $87.28 | $68.59 | $79.44 |
| Sep-2024 | $78.43 | $65.87 | $72.85 | Sep-2029 | $83.39 | $69.74 | $77.33 |
| Oct-2024 | $76.90 | $67.13 | $72.80 | Oct-2029 | $82.06 | $69.57 | $76.82 |
| Nov-2024 | $81.21 | $73.27 | $77.86 | Nov-2029 | $86.91 | $76.75 | $82.62 |
| Dec-2024 | $76.16 | $71.06 | $73.91 | Dec-2029 | $81.54 | $75.06 | $78.69 |

# Appendix E: Conservation Supply Curve Development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# OVERVIEW

This Appendix provides an overview of the general Council methodology for estimating the conservation resource potential in the region and describes the major sources of information used to prepare that analysis. It also provides links to spreadsheets containing the detailed input assumptions and specific source data used for each of the measures in the Council's conservation supply curves.

The Council estimates costs and savings for over 1,400 measures. These costs and savings are used to develop supply curves of conservation potential available by year. The supply curves represent the amount of conservation available at different cost levels. Costs are expressed as TRC (Total Resource Cost) net levelized costs so they can be compared to the costs of power purchases and the costs of new resource development.[1] The Council uses an in-house model called ProCost to calculate TRC net levelized cost. The following sections describe the "global" inputs and methodology used by the Council in its assessment of regional conservation resource potential.

## *Cost-Effectiveness Methodology Used in the Portfolio Analysis Model*

The Council uses a multi-step process to evaluate conservation cost-effectiveness. Conservation supply curves are constructed based on cost and savings available from over 1,400 conservation measures across the residential, commercial, industrial, agriculture and the electric utility system sectors. The conservation supply curves, annual deployment limitations, and the seasonal and time of day availability of conservation data are provided as inputs to the Regional Portfolio Model (RPM). Data on the cost and availability of generating resource options are also provided to the RPM. The RPM tests plans for the development of conservation and generation resources over 750 different futures. The RPM analysis produces strategies for conservation and generation resource development that have lowest cost and lowest risk outcomes for the region. The Council then considers the RPM conservation strategies, along with practical considerations, to develop near-term conservation targets and actions as well as cost-effectiveness guidance for near-term conservation program decisions. The process is outlined in Figure E-1.

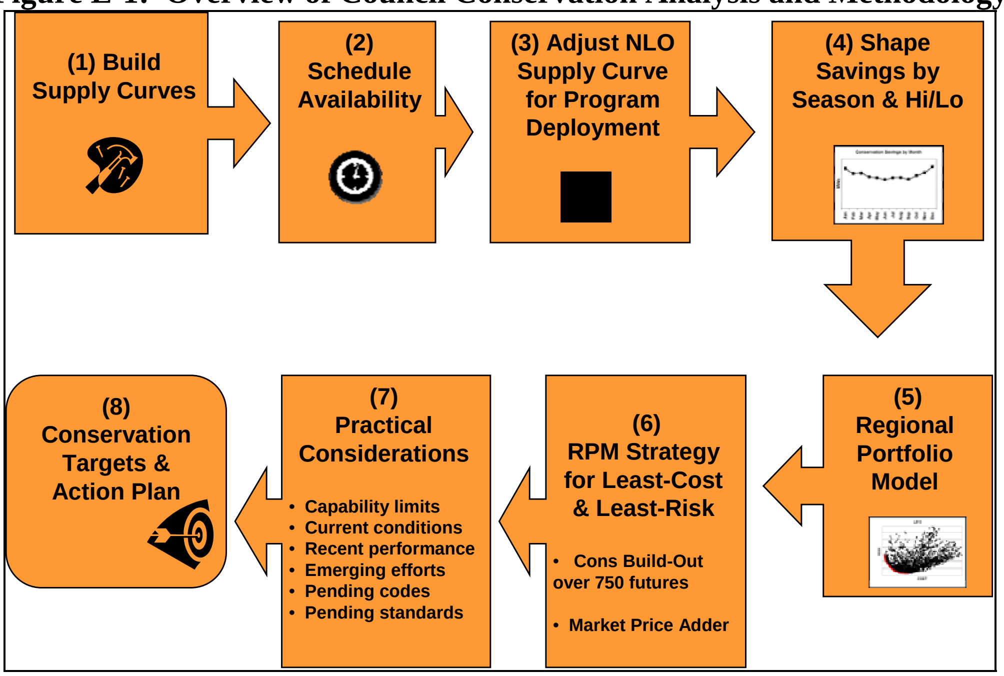
As with all other resources, the Council uses the RPM to determine how much conservation is cost-effective to develop.[2] The RPM compares resources, including conservation on a "generic" level. That is, it does not model a specific combined cycle gas or wind project nor does it model specific conservation measures or programs. Run time constraints limit the number of

[1] "TRC Net Levelized Cost" is computed based on all costs minus all benefits regardless of which sponsor incurs the cost or accrues the benefits. TRC Net Levelized Cost includes all applicable costs and all benefits. In addition to energy system costs and benefits, TRC Net Levelized Cost includes non-energy, other-fuel, O&M, periodic-replacement and risk-mitigation benefits and costs. TRC Net Levelized Cost corresponds to TRC B/C ratios with regard to the costs and benefits included. Benefits are subtracted from costs, then levelized over the life of the program.

[2] A full explanation of how the RPM arrives at the cost-effective amount of conservation is described in Appendix J in the section entitled "The Sources of Increased Conservation".

conservation programs the RPM can consider. The RPM 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. Therefore, the Council simplifies the set of conservation measures available to the portfolio model. In the case of conservation, the model uses two separate supply curves.

**Figure E-1: Overview of Council Conservation Analysis and Methodology**




These two supply curves, one for discretionary or non-lost opportunity (NLO) resources and a second for lost opportunity (LO) resources, depict the amount of savings achievable at varying levelized costs. The estimates of costs and savings in the supply curves incorporate line loss savings, the value of deferred distribution capacity expansion, and the non-energy costs and benefits of the savings.[3] The available savings are also allocated to high-load and low-load time periods to reflect the time-based value of savings and savings impact on capacity needs.

## Decision Rules for Modeling Conservation Resource Acquisition in the Resource Portfolio Model

The reason the RPM uses separate LO and NLO supply curves is that if a LO conservation resource is not acquired when it is available, it cannot be acquired later (e.g., after the building is constructed) or cannot be cost-effectively acquired later (e.g., the cost of revisiting a home makes adding an increment of ceiling insulation non-cost effective). Since NLO conservation resources do not have this restricted "window of opportunity," the pace of their acquisition can be accelerated or slowed. Deferring the purchase of high-cost NLO conservation resources to periods when market costs are high reduces cost and risk. That is, a portfolio management strategy that acquires high-cost NLO conservation resources early results in higher cost and risk

[3] Line losses input assumptions based on estimates of marginal line losses avoided by reduced load between generation and the end point of consumption for both the transmission and local distribution system. Overall conservation avoids line losses that range between 9 percent and 10 percent depending on the load shape of each measure's savings.

than a strategy that defers their acquisition to periods in future when market prices are higher. If market prices are expected to increase over time, the value acquiring high-cost NLO conservation resource is less in the near-term than in the long term. However, since the acquisition of LO conservation resources cannot be deferred there is more value in purchasing these resources at higher cost. In order to reflect the difference in the flexibility and value of these two types of conservation resources the Council's RPM uses acquisition decision rules specific to each resource type.

The RPM models LO resources using twenty annual supply curves that represent the quantity of technically achievable conservation available each year from 2010 through 2029 at levelized cost from zero up to $400 per megawatt-hour ($2006$). The amount of LO conservation resources technically achievable each year increases based on the assumption that programs are able to capture an ever larger share of the available potential over time. The RPM can acquire these technically achievable LO resources each year up to the quantity it determines to be cost-effective over the full planning period and across the 750 futures tested by the RPM. Any LO conservation resource in the supply curve that is not acquired in a given year is not available for deployment in any future year.

The RPM decision rule for LO conservation also reflects that much LO conservation can be developed through improvements in codes and standards, that either by statute or historical tradition, always *increase* in stringency. In order to mimic this effect, the RPM considers that once a cost-effectiveness level on these annual LO supply curves is selected (e.g., LO resources up to $100 per megawatt-hour), that cost-effectiveness level becomes the lower bound for all future LO acquisitions.

In contrast, the RPM models NLO conservation resource acquisition using a single supply curve representing the total technically achievable quantity of these resources over the entire 2010 through 2029 period at levelized cost from zero up to $400 per megawatt-hour (2006$). Because considerably more low-cost NLO conservation resources are immediately available at levelized cost below current market prices (e.g., over 4,000 average megawatts are available at a levelized cost less that $40 per megawatt-hour) constraints are placed on the maximum amount of NLO resources that can be acquired annually. If this were not done, the RPM would produce a portfolio strategy that called for the acquisition of all conservation resources costing less than current market prices in 2010. This strategy, while economically efficient, is clearly not practical since it would result in the acquisition of 3,000 to 4,000 average megawatts in 2010. Consequently, in the 6th Plan, a limit of 160 average megawatts per year was placed on the pace of NLO acquisitions.[4]

In addition to the constraint placed on the pace of NLO conservation resource acquisition, the RPM is also not permitted to "buy its way up the supply curve," acquiring only the least expensive conservation measures the in the near term of the planning period. Instead, NLO the supply curve is modified so that in the near term the RPM must select NLO resources from a

[4] The limit in the 5th Plan was 140 average megawatts per year and was based on the maximum historical levels of conservation acquisition prior to that plans adoption. While the 6th Plan was being developed it was clear that the region was exceeding the 5th Plan's annual conservation targets, so a higher pace was selected. Subsequent to the issuance of the draft 6th Plan the region's most recent conservation achievements were compiled. It now appears that 160 average megawatts per year is a conservative estimate of the maximum level of NLO achievable in the region, since both 2007 and 2008 savings were well above this level totally 200 and 235 average megawatts, respectively.

distribution of cost across the entire technically achievable supply curve with the upper limit based on trends in recent market prices.

This modeling framework is used to reflect the fact that conservation acquisition programs generally include measures across a wide range of levelized cost (e.g., residential weatherization programs include low-cost ceiling insulation and relatively higher cost window efficiency improvements). To represent a preference for lower cost NLO resources in the near term, the RPM samples more frequently from the lower cost portion of the supply curve than from the higher cost portion. The result of this modification is that the lowest cost block on the NLO supply curve is available to the RPM is at a cost of $23 per megawatt-hour. About 1,900 average megawatts are available at that price. After the RPM uses up this first block of low cost conservation, subsequent amounts of conservation, another 1,800 average megawatts, is available at increasing costs up to $400 per megawatt-hour.

## Determining the Cost-Effectiveness Limit for Conservation

The RPM determines the amount of conservation that is cost-effective by testing the value of acquiring increasingly costly conservation compared to purchasing additional power from the wholesale market. However, the cost-effectiveness limit for conservation is not the wholesale market price of power. This is because the future wholesale market price of power in the WECC is both uncertain and does not fully reflect the cost of developing new resources. For example, Resource Portfolio Standards (RPS) require that some utilities purchase renewable resources that are beyond their current need for power. As a result, this will create a systematic surplus in the wholesale power markets in the West. This market will largely consist of existing non-RPS resources, a portion of whose cost are already being borne by utility customers and need not be recovered in the market.

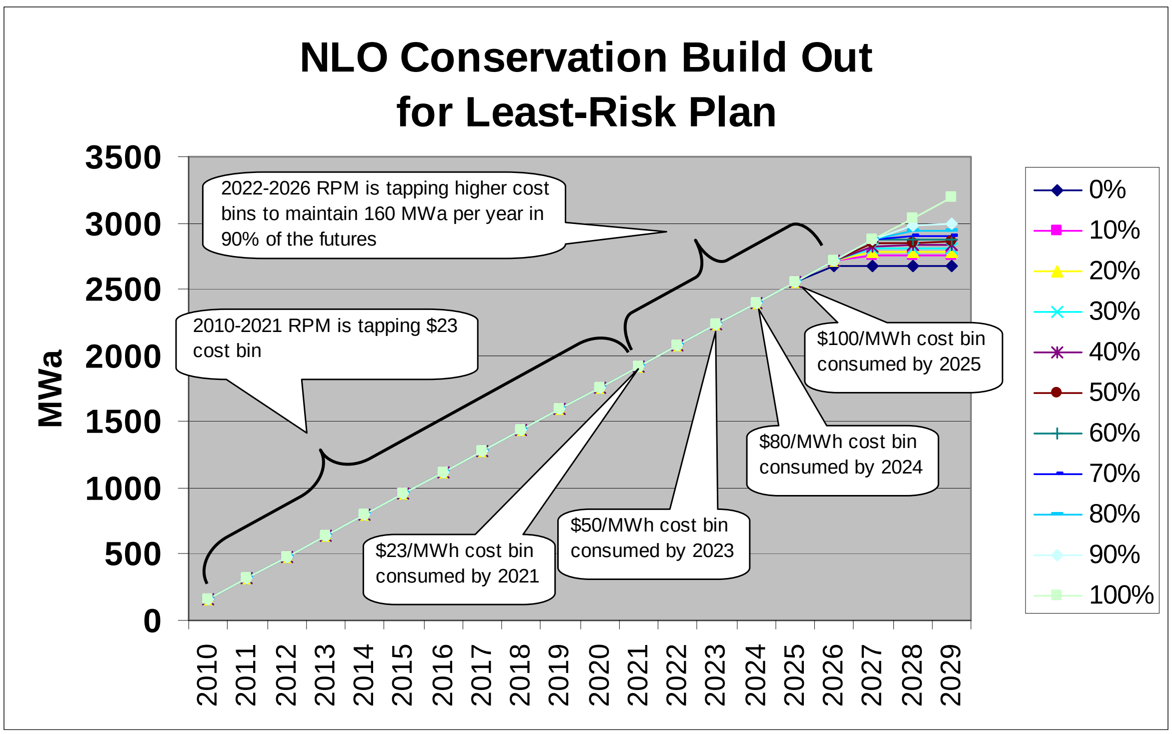
In lieu of using the wholesale market price another traditional approach to determining the "cost-effectiveness" limit for conservation has been to compare its cost to that of what is viewed as the "avoidable resources," for example a combined cycle combustion turbine. The problem with this is that in the Council's planning process the expected "online" date and long-rung cost of the "avoidable resource" varies across the 750 futures tested by the RPM. In order to address this uncertainty, the RPM tests alternative "adders" to the short-run market price to reflect the long run cost of new generating resources and the range of uncertainties for all key determinants of those cost across the 750 futures. Different adders are tested for LO and NLO resources.

The market adders for LO conservation resources along the efficient frontier ranged from a low of $20 per megawatt-hour over market prices at the least-cost end of the efficient frontier to $50 per megawatt-hour over market prices adder at the least-risk end. In both least-risk and least-cost cases the NLO adder was $80 per megawatt-hour, significantly higher than the LO adder. The reason for this is that there is a large quantity of low cost NLO resources and the pace their of development is constrained such that the NLO adder does not affect the amount and average cost of NLO resources acquired until the very end of the planning period (i.e., post-2025). To confirm this Council compared the amount of NLO resources developed using a $10 per megawatt-hour and with that developed using an $80 per megawatt adder. The amount of NLO resources developed through 2023 was identical regardless of which adder was used.

In contrast, the market price adder for LO conservation resources affects the amount of resources acquired and their average cost beginning in 2010. This means that the RPM tests the effect of the market adder for LO conservation resources every year of planning period for each of the 750 futures. As a result, when the RPM tests a market price adder for LO conservation resources that results in acquisition costs that are too high, the addition of high cost resources increases the net present value cost of the power system in all futures where market prices are lower. The RPM then test alternative LO market price adders until the one that produces the lowest cost portfolio for each level of risk is identified. It can be inferred from this that the near term market price adder for NLO conservation resource should be similar to the LO adder since the acquisition of high cost NLO resources would produce the same result (i.e., a higher net present value cost to the power system).

Figure E-2 shows the average quantity of NLO conservation resources acquired across all 750 futures tested in the RPM for the least risk plan identified by the RPM. As can be seen from this figure the RPM acquires NLO conservation resources up to the160 average megawatt per year limit through 2025. In fact, there are no futures where the pace falls below 160 average megawatts per year through 2025.

**Figure E-2: NLO Conservation Resources Acquired Across 750 Futures with a $80/MWh "Market Adder"**




A review of Figure E-2 also reveals that the RPM develops about 2,400 average megawatts of NLO conservation resources by the end of 2025 in all 750 futures. Based on the Council's NLO conservation resource supply curve, in order to for the RPM to acquire this quantity of NLO conservation resources by the end of 2025 it acquires conservation resources at levelized cost up to $70 per megawatt-hour over this time period. Moreover, in 90 percent of the futures, the RPM acquires over 2,600 average megawatts by the end of 2025. In order to for the RPM to acquire this quantity of NLO conservation resources by the end of 2025, the RPM must acquire conservation resources up to a levelized cost of $100 per megawatt-hour. Therefore, it appears that the near term market adder for NLO must be large enough to secure NLO resources with levelized cost up to $100 per megawatt-hour, but no higher than the $50 per megawatt-hour market adder for LO resources to avoid purchases that prove too costly in the long run.

There are two final steps in establishing the cost-effectiveness threshold for conservation measures and programs. First, as describe above the NLO and LO conservation supply curves described in Chapter 4 are compared to the "expected value" amount of LO and NLO resources developed by the RPM. The final 6th Plan calls for the development of 5,960 average megawatts of conservation by 2030, of which 3,090 average megawatts are lost-opportunity resources and 2,870 average megawatts are non-lost opportunity resources. In order to obtain these quantities of conservation from the 6th Plan's conservation supply curves would require purchasing up to a cost of $100 per megawatt-hour for a measure with the load shape of all conservation in the 6th Plan and an expected measure life of 20 years. As a point of comparison, new generating facilities currently going into service have levelized cost that range from $80 to $120 per megawatt-hour.

However, as stated previously, the use of levelized cost does not capture the value of each measures savings over the course of a day or year nor does it capture any non-energy benefits or costs. Therefore, in order to determine the cost-effectiveness is each conservation measure or program must tested using the Council's PROCOST model or similar model which accounts for the load shape of the measure or programs savings, non-energy benefits and/or cost and which applies the market price adders described above to a single forecast of future wholesale market prices. As described previously, these "adders" adjust the short run market prices to reflect the uncertainty surrounding the long-run cost of acquiring and operating new generating resources across a wide range of potential future conditions, including potential carbon control costs. It appears that a market adder of $50 per megawatt-hour for LO resources and $35 per megawatt-hour over near-term market prices would result in cost-effective conservation resource development.

The PROCOST model computes the present value of all of a conservation measures costs and benefits based on a total resource cost analysis. The Council uses a measures total resource cost benefit-to-cost ratio, not its levelized cost, to determine whether a measure is cost-effective. This ratio captures all the time-differentiated value of a measure's energy and capacity savings, its non-energy benefits and costs, the regional Act 10 percent credit and the measures direct and administrative costs.

Table E-1 shows the regional achievable savings by sector and major measure bundle derived using a cost-effectiveness limit of $100 per megawatt-hour for both lost-opportunity and non-lost-opportunity conservation. The values in this table are based on the Council's medium load forecast and therefore, the actual mix of measures targeted at new construction versus retrofit will differ. Savings are shown for both the near term (2014) and for the entire period covered by the 6th Plan (through 2029).

The purpose of Table E-1 is to show the major sources of energy efficiency identified in the Council's 6th Plan. It is not intended to dictate either the measures or the pace of their acquisition to be included in utility or system benefits charge administrator programs.

**Table E-1:  Estimated Cost-Effective Conservation Potential in Average Megawatts 2010-2014 and 2010 - 2029**

| Measure Bundle | MWa by 2014 | MWa by 2029 | Description of Bundle |
|---|---|---|---|
| **Residential** | | | |
| **Heat Pump Water Heater** | 12 | 490 | Energy Star heat pump water heater |
| **Television and Set Top Box** | 44 | 470 | Energy Star 5.0 or better televisions |
| **Computers and Monitors** | 33 | 360 | Efficient Desktop PC and Efficient Monitor (Residential & Commercial) |
| **Heat Pump Conversions** | 38 | 390 | Space heating conversion from electric resistance to heat pump |
| **Residential Appliances** | 22 | 170 | Clothes Washer, Dishwasher, Refrigerator, Freezer |
| **New Construction Shell** | 16 | 170 | Measures above current state or local codes |
| **Heat Pump Upgrades** | 10 | 100 | Space heating heat pumps better than code |
| **Weatherization** | 96 | 290 | Primarily high performance windows |
| **Ductless Heat Pump** | 65 | 195 | |
| **Lighting** | 259 | 285 | Includes both EISA and non-EISA covered lamps |
| **Showerheads** | 85 | 85 | 2.0 gallons per minute or lower flow rate |
| **Other Residential Measures** | 11 | 65 | |
| **All Residential Measures** | **692** | **3070** | |
| | | | |
| **Commercial** | | | |
| **Lighting Power Density** | 82 | 370 | Lamp, ballast and fixture improvements to lighting power density |
| **Interior Lighting Controls** | 13 | 90 | Occupancy controls for lighting areas not required by code |
| **Exterior Lighting** | 28 | 190 | Streetlight, parking, outdoor area lighting to high-efficiency sources and control |
| **Integrated Building Design** | 7 | 60 | Multiple measures applied in integrated design practice for select new buildings |
| **Packaged Refrigeration Equipment** | 8 | 50 | Efficient refrigerators beverage merchandisers, ice makers and vending machines |
| **Controls Commission Complex HVAC** | 32 | 110 | Commissioning on HVAC systems in buildings with complex HVAC systems |
| **Controls Optimization Simple HVAC** | 19 | 50 | Package Roof Top HVAC measures |
| **Grocery Refrigeration Bundle** | 28 | 90 | Grocery store refrigeration measures |
| **Computer Servers and IT** | 15 | 130 | Consolidation & virtualization & upgrade of servers in embedded server |
| **Network PC Power Management** | 15 | 70 | Control of a networked computer's advanced energy management systems |

| Measure Bundle | MWa by 2014 | MWa by 2029 | Description of Bundle |
|---|---|---|---|
| **Municipal Sewage Treatment & Water Supply** | 13 | 50 | Suite of measures for sewage treatment and water supply |
| **Cooking and Restaurant Equipment** | 7 | 40 | Ovens, steamers, hoods, sprayers, holding cabinets and other kitchen equipment |
| **Other Commercial Measures** | 23 | 110 | |
| **All Commercial Measures** | **290** | **1410** | |
| | | | |
| **Industrial** | | | |
| **Compressed Air** | 21 | 40 | Efficient equipment and system optimization across all industries |
| **Lighting** | 22 | 70 | Lamp, ballast, fixture and control improvements across all industries |
| **Fans** | 21 | 80 | Efficient equipment and system optimization across all industries |
| **Pumps** | 19 | 80 | Efficient equipment and system optimization across all industries |
| **Transformers** | 2 | 10 | Transformers more efficient than federal standards across all industries |
| **Belts** | 7 | 10 | Synchronous belts across all industries |
| **Material Handling** | 5 | 30 | Efficient equipment and system optimization across all industries |
| **Motors** | 1 | 10 | Efficient motor rewinds across all industries |
| **Hi-Tech** | 6 | 10 | Industry-Specific Processes:  Clean rooms and production facilities |
| **Pulp** | 3 | 10 | Industry-Specific Process:  Effluent treatment, refiners |
| **Paper** | 2 | 10 | Industry-Specific Process:  Pulp screening, effluent treatment |
| **Food Processing** | 13 | 30 | Refrigeration equipment and system optimization |
| **Food Storage** | 35 | 70 | Refrigeration equipment and controlled atmosphere system optimization |
| **Lumber & Wood Products** | 2 | 20 | Industry-Specific Process:  Material handling, drying, pressing |
| **Metals** | 0.1 | 0.5 | Industry-Specific Process:  Arc furnace |
| **Plant Energy Management** | 9 | 60 | Multiple-system O&M in large facilities |
| **Energy Project Management** | 17 | 120 | Multiple-system energy management, tracking and reporting in large facilities |
| **Integrated Plant Energy Management** | 16 | 100 | Top tier whole plant optimization in large facilities |
| **All Industrial Measures** | **200** | **760** | |
| | | | |

| Measure Bundle | MWa by 2014 | MWa by 2029 | Description of Bundle |
|---|---|---|---|
| **Agriculture** | | | |
| **Irrigation Hardware System Efficiency** | 35 | 70 | Leak reduction, lower pressure delivery, pump & system efficiency |
| **Irrigation Water Management** | 8 | 20 | Scientific irrigation scheduling |
| **Dairy Efficiency Improvement** | 4 | 10 | Refrigeration, Lighting and |
| **All Agricultural Measures** | **47** | **100** | |
| | | | |
| **Distribution** | | | |
| **Reduce system voltage** | 47 | 160 | Reduce system voltage w/ LDC voltage control method |
| **Light system improvements** | 8 | 80 | VAR management phase load balancing, and feeder load balancing |
| **Major system improvements** | 9 | 90 | Voltage regulators on 1 of 4 substations, and select |
| **Voltage control** | 4 | 40 | End of Line (EOL) voltage control method |
| **Unique system improvements** | 5 | 30 | Seattle City Light system implement EOL w/ major system improvements |
| **All Distribution Efficiency Measures** | **72** | **400** | |
| | | | |
| **All Sectors** | | | |
| **Total** | **1308** | **5740** | |

## The Costs of Conservation

The costs included in the Council's analyses are the sum of the total installed cost of the measure, and any operation and maintenance costs, or savings, associated with ensuring the measure's proper functioning over its expected life. If the use of an electric efficiency measure increases or decreases the use of another fuel, such as improving the efficiency of lighting in a commercial building may increase the use of natural gas for heating, the cost or savings of these impacts are included in the analysis.

## 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. That is, each measure's annual savings are evaluated for their effects on the power system over the 8,760 hours in a year.[5]

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

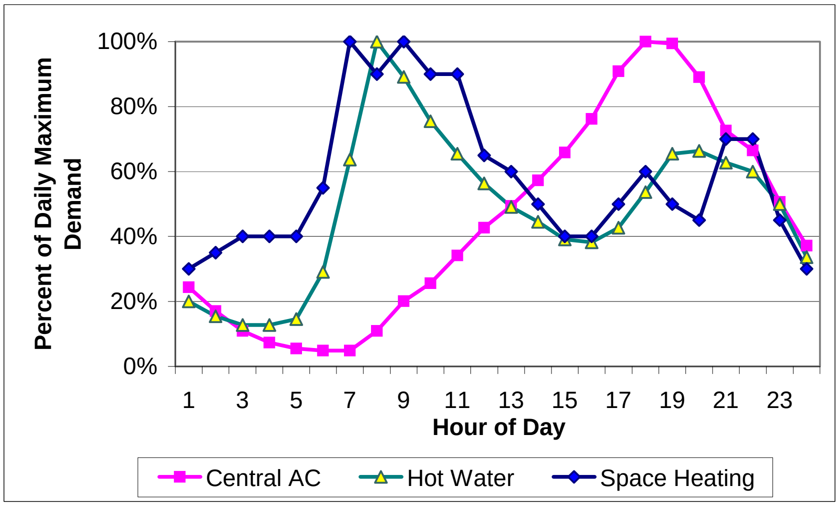
Given the interconnected nature of the West, regional wholesale power prices reflect the significant demand for summer air conditioning in California, Nevada and the remainder of the desert Southwest. Consequently, wholesale power prices are as high as or higher during the peak air conditioning season in July and August than they are when the Northwest system peak demand occurs in the winter. Consequently, 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.

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-3 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

[5] To simplify this analysis the Council divides each day and week into four time segments representing high, medium high, medium and low demand hours, resulting in four price "periods" per day for each month for a total of 48 prices per year.

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 during over the course of the entire day. The horizontal axis shows the hour of the day, with hour "0" representing midnight.

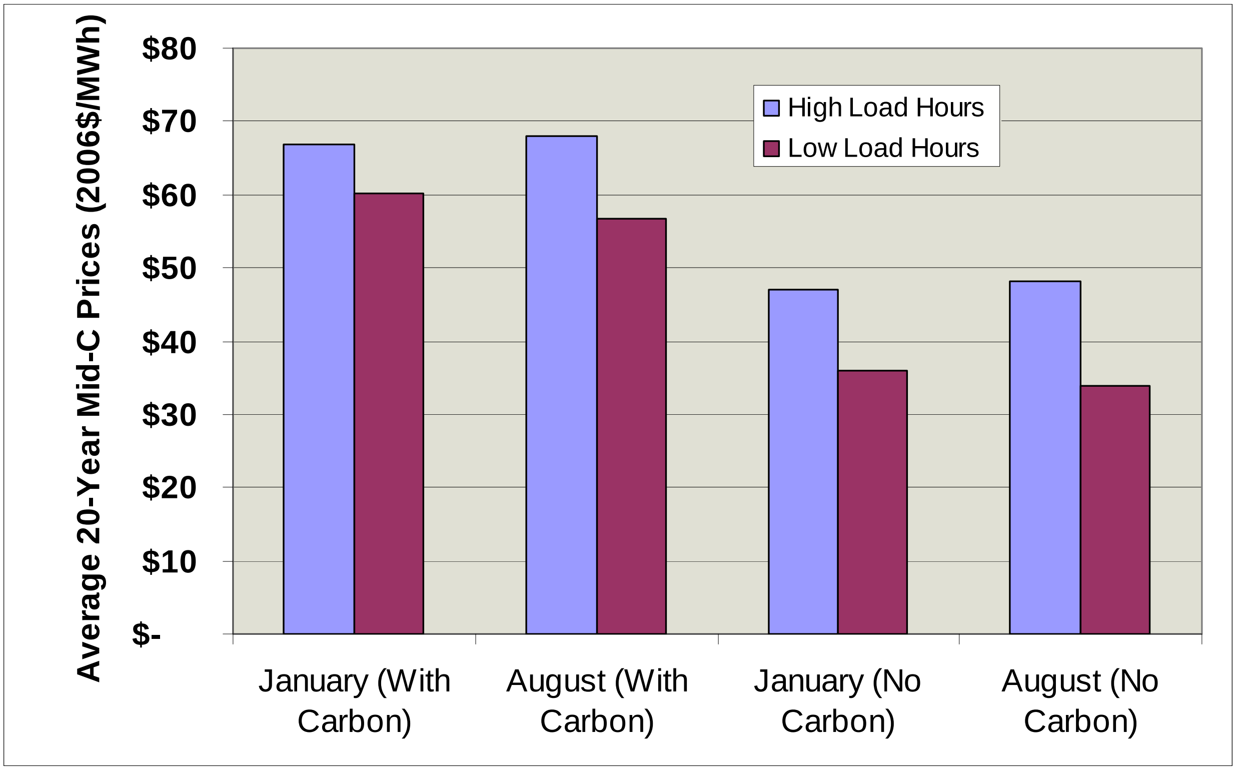
**Figure E-3: Hour Load Profile for Residential Central Air Conditioning Water Heating and Space Heating Conservation Savings**




As can be seen from inspecting Figure E-3, 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 over the course of typical summer and winter days. Figure E-4 shows the average levelized wholesale market prices at Mid-C for January and August for high and low load hours, with and without carbons costs. As can be seen from Figure E-4, high load hour savings are more valuable than those that occur during low-load hours both summer and winter. However, the gap between high- and low-load hour market prices narrows when average carbon costs are included. This occurs because increases in carbon cost have a greater impact on coal fired generating cost than on natural gas fired generation and across the WECC high-load hour electricity is being generated by natural gas turbines, while demand during low-load hours is met by coal-fired generation.

**Figure E-4:  Forecast Levelized Wholesale Power Market Prices at Mid Columbia Trading HUB for January and August High-Load and Low-Load Hours**



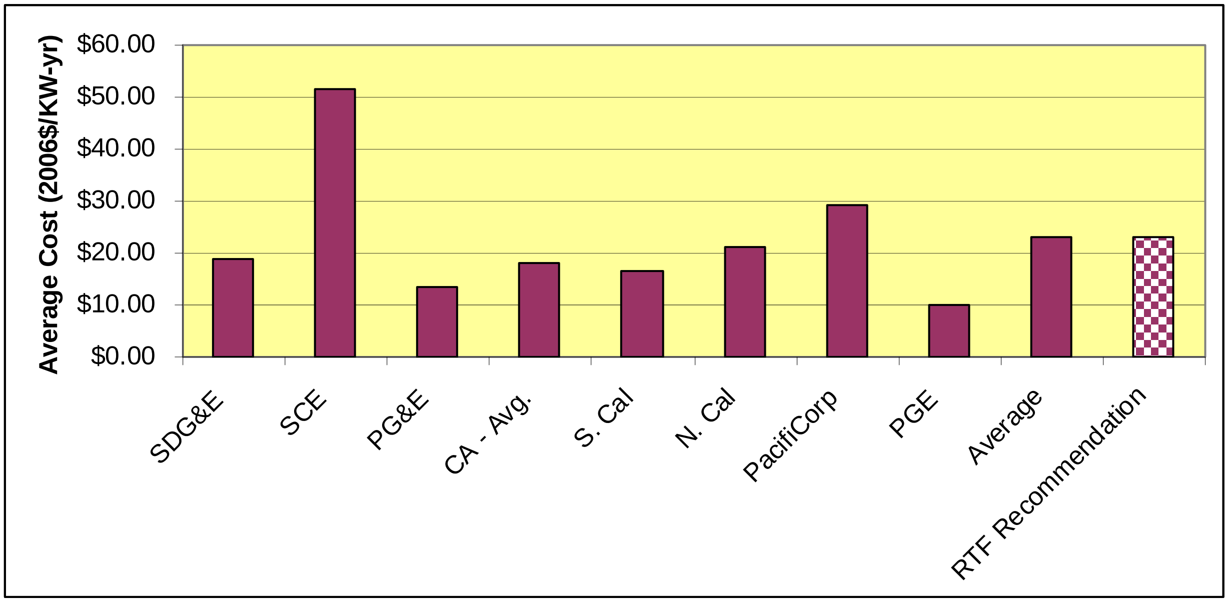

In order to capture this differential in benefits, the Council computes the weighted average time-differentiated value of the savings of each conservation measure based on its unique conservation load shape.  Each month's savings are valued at the avoided cost for that time period based on the daily and monthly load shape of the savings.  The weighted value of the all time period's avoided costs establishes the cost-effectiveness limit for a particular end use.

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.  The Council currently uses its "base case" AURORA model forecast of future wholesale market prices to determine conservation cost-effectiveness. However, in order to reflect the uncertainty of future market prices rather than a single market price forecast, the Council adjusts the AURORA market price forecast to incorporate the value that conservation provides as a hedge against future market price volatility. The derivation of this value is described fully in Chapter 9 of the sixth plan.

## *Value of Deferred Transmission and Distribution Capacity*

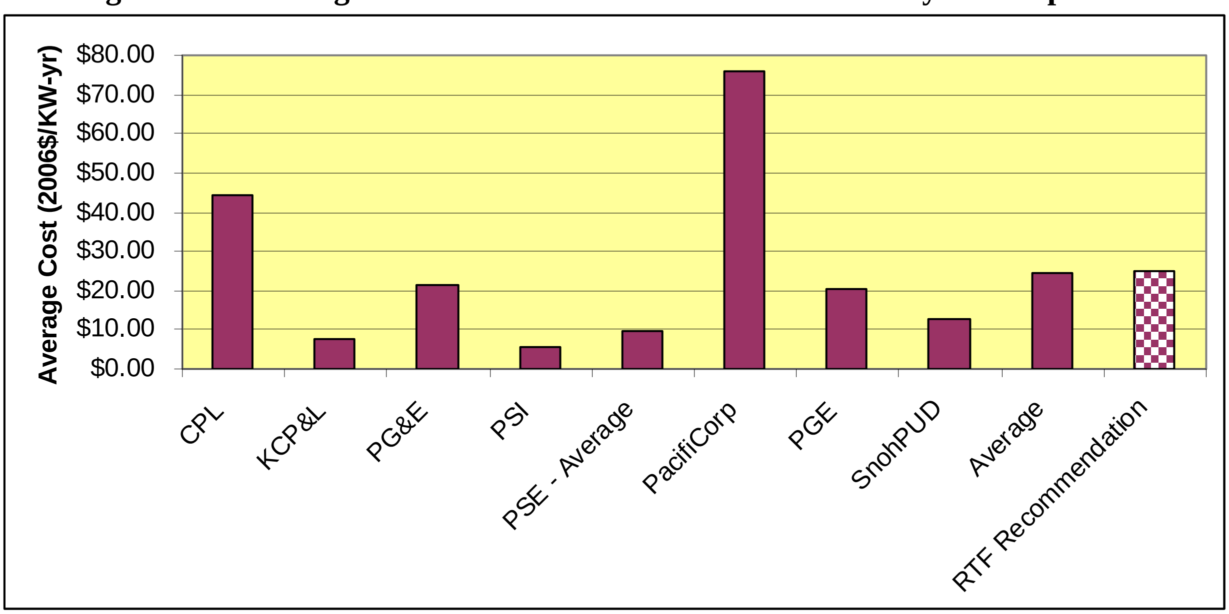
In addition to its value in offsetting the need for generation, conservation also reduces the need to expand local power distribution system capacity.  The next step used to determine conservation's cost effectiveness is to determine whether the installation of a particular measure will defer the installation 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) to develop a representative estimate of avoided transmission and distribution costs. Figure E-5 presents data for the avoided cost of transmission system expansion and Figure E-6 presents data for the avoided cost of distribution system expansion.

**Figure E-5: Average Avoided Cost of Deferred Transmission System Expansion**




After reviewing this data the RTF recommended a value of $23/kW-yr for "representative" of avoided transmission system expansion cost and $25/kW-yr as "representative" of avoided cost of distribution system expansion. The Council adopted the RTF recommended value for distribution system avoided cost. However, because the value of avoiding the transmission system investments is already included in the wholesale market prices produced by the AURORA model the Council did not use the RTF estimate of the benefits of deferring transmission system expansion so as to avoid double counting.

**Figure E-6: Average Avoided Cost of Deferred Distribution System Expansion**



As discussed above, due to the interconnected nature of the West coast wholesale power market, conservation measures that reduce consumption during the on peak hours are the most valuable, even though the region has significant peaking resources from the hydro-system. 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.[6] 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 was also used to determine the "on-peak" savings for each conservation measure.

## *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.[7] The Council does this by calculating the Act credit as 10 percent of the value of energy saved at wholesale market prices, plus ten percent of the value of savings from deferring electric transmission and distribution system expansion and risk avoidance. The Council's Resource Portfolio Model (RPM) does not include the Act's credit for conservation as a decision criteria, so the levelized cost of conservation in the supply curves used by the RPM must be adjusted downward so that this credit is reflected in the RPM's comparison of conservation cost with generating resource costs. The economic value of the Act credit for conservation varies by conservation measure. Each measure has a unique value of energy saved based on when the savings occur and a unique impact on distribution capacity based on the coincidence of savings with peak system loads.

[6] Some areas of the region now experience both summer and winter peaks of almost equal magnitude due to increased use of air conditioning.
[7] Northwest Power Act,§3(4)(D), 94 Stat. 2699.

## *Financial Input Assumptions*

The present value cost of conservation is determined by who pays for it. The RTF was asked to provide recommendations on the anticipated "cost-sharing" between utilities and consumers. Staff also developed estimates of the cost of capital and equity used to pay for conservation based on the mix of consumers in each of the major sectors. Tables E-2 through E-5 show the financial assumptions used in the economic analysis of conservation opportunities in each of the four major economic sectors.

**Table E-2: Residential Sector Financial Input Assumptions**

| Sponsor Parameters | Customer | Wholesale Electric | Retail Electric | Natural Gas |
|---|---|---|---|---|
| Real After-Tax Cost of Capital | 3.90% | 4.40% | 4.90% | 5.00% |
| Financial Life (years) | 15 | 1 | 1 | 1 |
| Sponsor Share of Initial Capital Cost | 35% | 20% | 45% | 0% |
| Sponsor Share of Annual O&M | 100% | 0% | 0% | 0% |
| Sponsor Share of Periodic Replacement Cost | 100% | 0% | 0% | 0% |
| Sponsor Share of Administrative Cost | 0% | 50% | 50% | 0% |
| Last Year of Non-Customer O&M & Period Replacement | | 20 | | |

**Table E-3: Commercial Sector Financial Input Assumptions**

| Sponsor Parameters | Customer | Wholesale Electric | Retail Electric | Natural Gas |
|---|---|---|---|---|
| Real After-Tax Cost of Capital | 6.70% | 4.40% | 4.90% | 5.00% |
| Financial Life (years) | 20 | 1 | 1 | 1 |
| Sponsor Share of Initial Capital Cost | 35% | 10% | 55% | 0% |
| Sponsor Share of Annual O&M | 100% | 0% | 0% | 0% |
| Sponsor Share of Periodic Replacement Cost | 100% | 0% | 0% | 0% |
| Sponsor Share of Admin Cost | 0% | 50% | 50% | 0% |
| Last Year of Non-Customer O&M & Period Replacement | | 20 | | |

**Table E-4: Industrial Sector Financial Input Assumptions**

| Sponsor Parameters | Customer | Wholesale Electric | Retail Electric | Natural Gas |
|---|---|---|---|---|
| Real After-Tax Cost of Capital | 7.60% | 4.40% | 4.90% | 5.00% |
| Financial Life (years) | 20 | 1 | 1 | 1 |
| Sponsor Share of Initial Capital Cost | 35% | 10% | 55% | 0% |
| Sponsor Share of Annual O&M | 100% | 0% | 0% | 0% |
| Sponsor Share of Periodic Replacement Cost | 100% | 0% | 0% | 0% |
| Sponsor Share of Admin Cost | 0% | 50% | 50% | 0% |
| Last Year of Non-Customer O&M & Period Replacement | | 20 | | |

**Table E-5: Agriculture Sector Financial Input Assumptions**

| Sponsor Parameters | Customer | Wholesale Electric | Retail Electric | Natural Gas |
|---|---|---|---|---|
| Real After-Tax Cost of Capital | 7.60% | 4.40% | 4.90% | 5.00% |
| Financial Life (years) | 5 | 1 | 1 | 1 |
| Sponsor Share of Initial Capital Cost | 35% | 10% | 55% | 0% |
| Sponsor Share of Annual O&M | 100% | 0% | 0% | 0% |
| Sponsor Share of Periodic Replacement Cost | 100% | 0% | 0% | 0% |
| Sponsor Share of Admin Cost | 0% | 50% | 50% | 0% |
| Last Year of Non-Customer O&M & Period Replacement | | 20 | | |

# RESIDENTIAL SECTOR

## *Residential Sector Definition and Coverage*

For the Council's conservation analysis the residential sector includes single family, multifamily and manufactured homes buildings. Single family buildings are defined as all structures with four or fewer separate dwelling units, including both attached and detached homes. Multifamily structures include all housing with five our more dwelling units, up to four stories in height.[8] Manufactured homes are dwellings regulated by the US Department of Housing and Urban Development (HUD) construction and safety standards (USC Title 42, Chapter 70). Modular homes, which are regulated by state codes, are considered single family dwellings.

One of primary inputs into the residential sector conservation assessment is the number of units that each conservation measure or measure bundle could be applied to in the region. Space conditioning savings are a function of both the characteristics of the structure and the climatic conditions where the home is located. Therefore, the Council's assessment includes estimates of the number of new and existing dwelling units of each type (i.e., single family, multifamily, manufactured homes) in nine different climate zones. The Council defines climate zones by specific combinations of heating and cooling degree days. Table E-6 shows the nine climate zones in the region.

## *Measure Bundles*

Nearly 60 individual residential-sector measures are analyzed in the Sixth Power Plan. In the case of heat pumps and central air conditioning three measures were consolidated into a single bundle of related measures. Two levels of efficiency above the current federal minimum standards were tested, HSPF 8.5/SEER 14 and HSPF 9.0/SEER 14. For purposes of analytical expediency it was assumed that when a high efficiency heat pump was installed it would also undergo commissioning to ensure it functions properly and that it would have controls installed to optimize its operation. In addition, it was also assumed that in the case of existing homes the duct system would be sealed and in the case of new homes the duct system would be located inside the conditioned space or be sealed. As a result "duct sealing" and "heat pump commissioning and controls" are not identified separated in the supply curve, but are bundled

[8] The conservation potential for water heating, lighting, appliances and consumer electronics in high rise multifamily dwellings (i.e., those covered by non-residential codes) are included in the residential sector. However, the savings from building shell and HVAC improvements in high rise multifamily buildings is not included in the Council's assessment of regional conservation potential due to lack of data.

with “heat pump efficiency upgrades” and “heat pump conversions.” These measure bundles do not and should not dictate the way measures are bundled for programmatic implementation.

**Table E-6: Regional Heating and Cooling Climate Zones**

| Climate Zone | Heating Degree Days | Cooling Degree Days |
|---|---|---|
| Climate Zone: Heating 1 - Cooling 1 | < 6,000 | <300 |
| Climate Zone: Heating 1 - Cooling 2 | < 6,000 | > 300 - 899 |
| Climate Zone: Heating 1 - Cooling 3 | < 6,000 | > 900 |
| Climate Zone: Heating 2 - Cooling 1 | 6,000 - 7,499 | <300 |
| Climate Zone: Heating 2 - Cooling 2 | 6,000 - 7,499 | > 300 - 899 |
| Climate Zone: Heating 2 - Cooling 3 | 6,000 - 7,499 | > 900 |
| Climate Zone: Heating 3 - Cooling 1 | > 7,500 | <300 |
| Climate Zone: Heating 3 - Cooling 2 | > 7,500 | > 300 - 899 |
| Climate Zone: Heating 3 - Cooling 3 | > 7,500 | > 900 |

Measures are also consolidated into three types of application modes. These modes are new, natural replacement and retrofit. The new mode applies primarily to new buildings or new equipment. The natural replacement mode applies to subsystems and equipment within buildings that are replaced on burnout, at the end of their useful life, or at the time of remodel of the building or system within a building. Examples of this mode include appliance and water heater replacements and conversions of electric forced air furnaces to air source heat pumps are assumed to take place when the existing furnace needs to be replaced. Retrofit mode is used where a measure or a building subsystem upgraded, replaced or retired before the end of its useful life. The installation of insulation, window replacements and installation of ductless heat pumps to provide higher efficiency supplemental space conditioning are all examples of retrofit measures.

There are three reasons to distinguish the new, natural replacement and retrofit application modes. First, costs and savings can be different by application mode. Second, in the case of new and natural replacement, the available stock for the measure depends on the forecast of new additions and replacement rate for equipment. These opportunities are tracked separately over course of the forecast period and limit the annual availability of conservation opportunities. Third, the Council’s portfolio model treats new and natural replacement applications as lost-opportunity measures that can only be captured at the time of construction or natural replacement.

Measure costs, savings, applicability, and achievability estimates are identified separately for each of the new, natural replacement and retrofit application modes. The Council analyzes measure costs and savings on an incremental basis. Measure cost is the incremental cost over what would be done absent the measure or program. The same is true for savings. Incremental measure costs and savings can be different depending on the application mode. For example, incremental costs of high performance windows in a new application only include the additional cost of the windows required by code. In a retrofit application, the labor cost of removing and replacing the existing window are added to the measure cost.

## *Overview of Methods*

Measure costs and savings are developed at a level of detail compatible with data availability, expected variance in measure costs and savings, the diversity of measure applications and practical limitations on the number of measures that can be analyzed. Costs and savings are based both on engineering estimates as well as estimates based on results from the operation of existing programs. Savings potential is the product of savings per unit and the forecast of number of units that the measure is applicable to. For the residential sector measures the unit of measure is a function of the measure type. Most measures apply to a fraction of the building stock in a particular building type. For example, insulation measures are a function of the number of households with electric heat, refrigerator efficiency improvements are a function of the number of refrigerators that are replaced or purchase new each year and the potential savings from ductless heat pumps are function of the number of single family homes with zonal electric heating systems.

For every measure or practice analyzed, there are four major methodological steps to go through. These steps establish baseline conditions, measure applicability, and measure achievability. For the residential-sector conservation measures, each of these is treated explicitly for each measure bundle.

### Baseline Characteristics

Baseline conditions are estimated from current conditions for existing buildings and systems. Estimates of current conditions and characteristics of the building stock come from several sources. Key among these are the market research projects of the Northwest Energy Efficiency Alliance (NEEA), selected studies from utilities, Energy Trust of Oregon, and other sources.

For new buildings and new and replacement equipment, baseline conditions are estimated from a combination of surveys of new buildings, state and local building energy codes and federal and state appliance efficiency standards. The most recent survey data used is from the NEEA New Single Family and New Multifamily Buildings Characteristics studies completed in 2007 which looked at buildings built in the 2003-2004. Codes and standards are continually being upgraded. The baseline assumptions used in the Sixth Power Plan are those that were adopted at the end of 2008, with a few exceptions. Some of these include standards that are adopted now but with effective dates that occur in the future. For such codes or standards, both savings estimates and the demand forecast reflect the effective dates of adopted standards. Baseline characteristics for major appliances (washers, dishwashers, refrigerators and freezers) are the national sales weighted average efficiency levels. This data was obtained from the American Home Appliance Manufacturer's Association (AHAM). Cost data for appliances was obtained from an analysis of the Oregon Residential Energy Tax Credit data and Internet searches. Heating, cooling, insulation and window cost were obtained from an analysis of program data from Puget Sound Energy and the Energy Trust of Oregon.

### Measure Applicability

Measure applicability reflects several major components. First is the technical applicability of a measure. Technical applicability includes what fraction of the stock the measure applies to. Technical applicability can be composed of several factors. These include the fraction of stock that the measure applies to, overlap with mutually exclusive measures and the existing saturation of the measure. Existing measure saturation reflects the fraction of the applicable stock that has already adopted the measure and for which savings estimates do not apply. There are hundreds of applicability assumptions in the residential-sector conservation assessment. Applicability assumptions by measure appear in the three supply curve summary workbooks. Table E-6 shows the measures covered by each of these three workbooks.

## Measure Achievability

The Council assumes that only a portion of the technically available conservation can be achieved. Ultimate achievability factors are limited to 85 percent of the technically available conservation over the twenty-year forecast period. In addition to a limit of 85 percent, the Council considers near-term achievable penetration rates for bundles of conservation measures. Several factors are used to estimate near-term achievability rates. Recent experience with region wide conservation program accomplishments is one key factor. But in addition to historic experience, the Council also considers a bottom-up approach to estimate near-term achievability.

In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described
In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described
and consideration of likely delivery mechanisms. This detailed bottom-up approach is a new element in the Sixth Power Plan. In the Sixth Plan, the Council uses a suite of typical ramp rates to reflect near-term penetration rates. For example, measures involving emerging technology might start out at low penetration rates and gradually increase to 85 percent penetration. Measures suitable for implementation by a building code or a federal equipment standard might increase rapidly to 85 percent penetration in new buildings and major remodels. Measures requiring new delivery mechanisms might ramp up slowly. Simple measures with well-established delivery channels, like efficient shower heads, might take only half a dozen years to fully implement. Whereas retrofit measures in complex markets might take 20 years to reach full penetration. Assumptions for the bottom-up approach are detailed in the conservation supply curve workbooks shown in Table E-7 below.

**Table E-7: Measures Covered in Residential Supply Curve Summary Worksheets**

| Measures | Worksheet Name |
|---|---|
| New and existing lighting<br>Clothes washers and dryers<br>Dishwashers<br>Refrigerators and Freezers<br>Microwaves and ovens<br>High efficiency water heaters, including heat pump water heaters<br>Showerheads<br>Waste water heat recovery<br>Solar water heating<br>Solar photovoltaic | PNWResDHWLight&ApplianceCurve_6thPlanv1_7.xls |
| Thermal Envelop Improvements (insulation, windows, air sealing)<br>High Efficiency heat pumps (upgrades and system conversions)<br>High Efficiency air conditioners (Room AC and Central AC)<br>Duct Efficiency (sealing and interior ductwork)<br>Heat pump commissioning and controls<br>Ductless heat pumps | PNWResSpaceConditioningCurve_6thPlanv1_8.xls |
| Televisions<br>Set Top Boxes<br>Desktop computers<br>Desktop computer monitors | PNWConsumerElectronicsSupplyCurve_6thPlanv1_7.xls |

### Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on. In the residential sector analysis, the applicable unit estimates for space conditioning, water heating, lighting and appliances are based on the number of existing housing units and forecast of future housing growth from the Council's Demand Forecasting Model. The housing units from the forecasting model were allocated to climate zones based on the population weighted average heating and cooling degrees for each county in the region. The housing unit data and zone allocations are all contained in the spreadsheet entitled "PNWResSectorSupplyCurveUnits_6thPlan.xls." The estimates of physical units available include the number of units available annually. For example, for new buildings, the estimate of available new building stock is taken from the Council's baseline forecast for annual additions by building type. Similarly for equipment replacement measures the annual stock available is taken from estimates of the turnover rate of the equipment in question. For retrofit measures, the annual stock availability is a fraction of the estimated stock remaining at the end of the forecast period.

The number of applicable and achievable units for consumer electronics were derived from national and regional sales data and forecast for televisions, set top boxes and desktop computers and monitors. The estimates of physical units for these products are embedded in the consumer electronics supply curve workbooks cited in Table E-7.

## *Guide to the Residential Conservation Workbooks*

Table E-8 provides a cross-walk between the measures included in the Council's assessment of regional conservation potential in the residential sector and the name of the individual workbooks. The most recent versions of these workbooks are posted on the Council's website and are available for downloading.

**Table E-8: Residential Sector Supply Curve Input Workbooks**

| File Scope | File Name |
|---|---|
| **Lighting - Existing** | EStarLighting_ExistingFY09v1_1.xls |
| **Lighting - New** | EStarLighting_NewFY09v1_0.xls |
| **Refrigerator** | EStarRefrigeratorFY09v1_0.xls |
| **Dishwasher** | EStarResDishwasherFY09v1_0.xls |
| **Freezer** | EStarResFreezersFY09v1_0.xls |
| **Window AC Upgrades** | EStarRoomACFY09v1_0.xls |
| **Clothes Washers and Dryers - Multifamily** | EStarWasher_DryerMultifamily_FY09v1_0.xls |
| **Clothes Washers and Dryers - Single Family** | EStarWasher_DryerSingleFamily_FY09v1_1.xls |
| **Marginal Cost and Load Shape Date File (needed to run Procost models to update cost-effectiveness)** | MC_and_LoadShape_6P.xls |
| **Climate Zone Assignments by State and County** | PNWClimateZones_6thPlan.xls |
| **Consumer Electronics (Televisions, Set-top-Boxes, Computers & Monitors)** | PNWConsumerElectronicsSupplyCurve_6thPlanv1_7.xls |
| **Housing Foundation Types** | PNWFoundTypes-_6thPlan.xls |
| **Residential Appliance, Lighting and Domestic Water Heating Supply Curve for Draft 6th Plan** | PNWResDHWLight&ApplianceCurve_6thPlanv1_7.xls |
| **Residential Supply Curve Housing and Appliance Units** | PNWResSectorSupplyCurveUnits_6th_Fnl.xls |
| **Residential Space Conditioning Supply Curve** | PNWResSpaceConditioningCurve_6thPlanv1_8.xls |
| **New and Existing Single Family & Manufactured Home HVAC Conversions and Upgrades to High Efficiency Heat Pumps** | ResDHP&HPConversions_UpgradesFY09v1_5.xls |
| **Showerhead** | ResDHW_2_0gpmShowerheads_FY09v1_0.xls |
| **Efficient Water Heater Tanks and Heat Pump Water Heaters** | ResDHWFY09v1_1.xls |
| **Waste Water Heat Recovery** | ResDHWHeatRecoveryFY09v1_1.xls |
| **New Multifamily Thermal Shell** | ResNewMF_wAdvancedLightingsqftFY09v1_2.xls |
| **New Manufactured Home Thermal Shell** | ResNewMH_wAdvancedLightingsqftFY09v1_2.xls |
| **New Single Family Thermal Shell** | ResNewSF_wAdvancedLightingsqftFY09v1_2.xls |
| **Microwaves and Ovens** | ResOven_MicrowaveFY09v1_0.xls |
| **Residential Sector Supply Curve Summary** | ResSectorConAsmnt_112509Summary.xls |
| **Multifamily Weatherization** | ResWxMF_w/AdvancedLightingsqftFY09v1_2.xls |
| **Manufactured Home Weatherization** | ResWxMH_w/AdvancedLightingsqftFY09v1_2.xls |
| **Single Family Weatherization** | ResWxSF_w/AdvancedLightingsqftFY09v1_2.xls |
| **Solar Domestic Water Heating** | SolarDHW_FY09v1_1.xls |
| **Solar Photovoltaic** | SolarPV_FY09v1_0.xls |

# COMMERCIAL SECTOR

## *Commercial Sector Definition and Coverage*

For the Council’s conservation analysis the commercial sector includes non-residential buildings except for industrial, as well as non-building economic activities such as street and highway lighting, outdoor area lighting, municipal sewage treatment, and water supply systems.

Commercial building floor area is one of the key drivers of the commercial conservation assessment. Floor area estimates are driven by economic forecasts of business activity, employment, demographics, and other factors such as floor area per employee. The development of the commercial floor area and load forecasts is described in Appendix C. The commercial building sector is categorized into 11 economic activity types and 18 separate building types. These building types are listed in Table E-9.

**Table E-9: Building Types Covered in Commercial Supply Curve Summary Worksheets**

| Primary Activity | Council Building Type | Gross Floor Area in Square Feet | Number of Stories | Note, Comment, or Example |
|---|---|---|---|---|
| **Office** | Large Office | > 100,000 | Any | |
| **Office** | Medium Office | 20,000 to 100,000 | Any | |
| **Office** | Small Office | < 20,000 | Any | |
| **Retail** | Big Box | > 50,000 | 1 | Includes some Grocery |
| **Retail** | Small Box | <50,000 | 1 | |
| **Retail** | High End | < 20,000 | 1 | High lighting density |
| **Retail** | Anchor | > 50,000 | >1 | |
| **Education** | K-12 | Any | Any | |
| **School** | University | Any | Any | University, community college |
| **Warehouse** | Warehouse | Any | Any | Excludes refrigerated warehouse |
| **Retail Food** | Supermarket | > 5000 | Any | |
| **Retail Food** | MiniMart | < 5000 | Any | |
| **Restaurant** | Restaurant | Any | Any | Fast food, sit-down, café & bar |
| **Lodging** | Lodging | Any | Any | Hotel, motel & residential care |
| **Health Care** | Hospital | Any | Any | Medical, surgical, psychiatric |
| **Health Care** | Other Health | Any | Any | Outpatient health, labs, ambulance |
| **Assembly** | Assembly | Any | Any | Churches, museums, airports, stadiums, etc. |
| **Other** | Other | Any | Any | Parking lots, fire protection, car wash, gasoline , cemetery, air traffic control |

Estimates of existing stock by building type and vintage cohort are based on data from the Commercial Building Stock Assessments from 2001 and 2004, construction data from F.W. Dodge, and other sources. Figure E-7 identifies floor area estimates for the 18 building types for 2010. Figure E-8 shows total historic and base case forecast commercial floor area for the period 1987 through 2029. Figure E-9 shows annual additions to commercial floor space for the same period. The year-by-year forecast of floor area by building type, employment and population used to estimate future stock is in the workbook Commercial Forecast 6P.xls identified in table E-13. The file also contains a detailed mapping of economic activity types to building types. Economic activity definitions are base on the North American Industry Classification System (NAICS) codes.

**Figure E-7: Commercial Floor Area by Building Type for 2010**

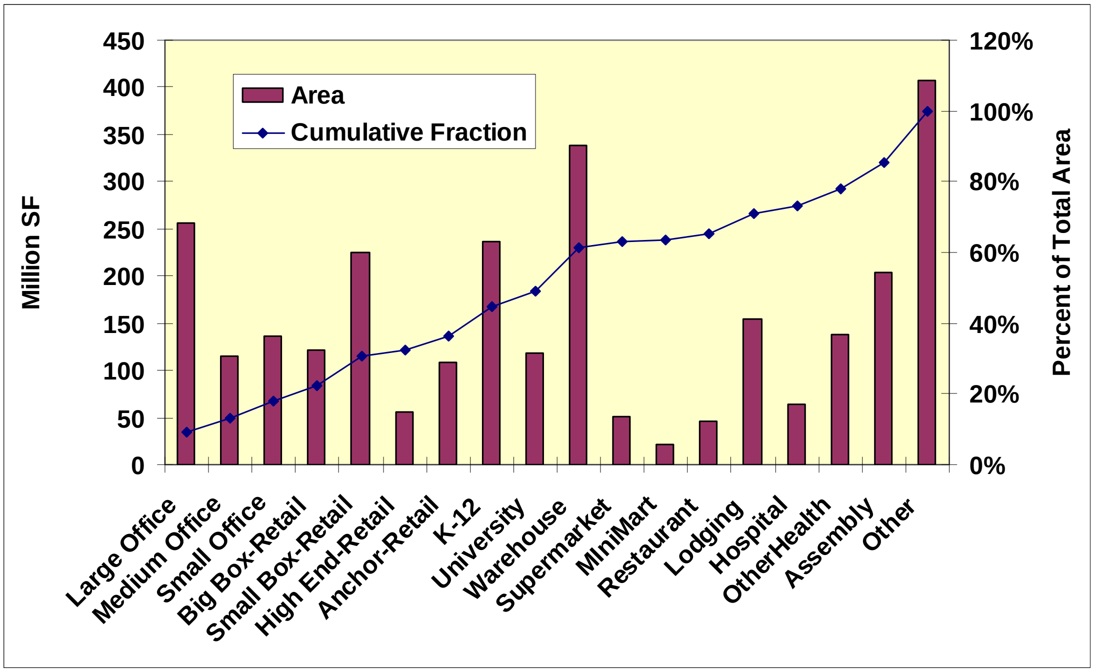



**Figure E-8: Total Commercial Floor Area 1987-2029**

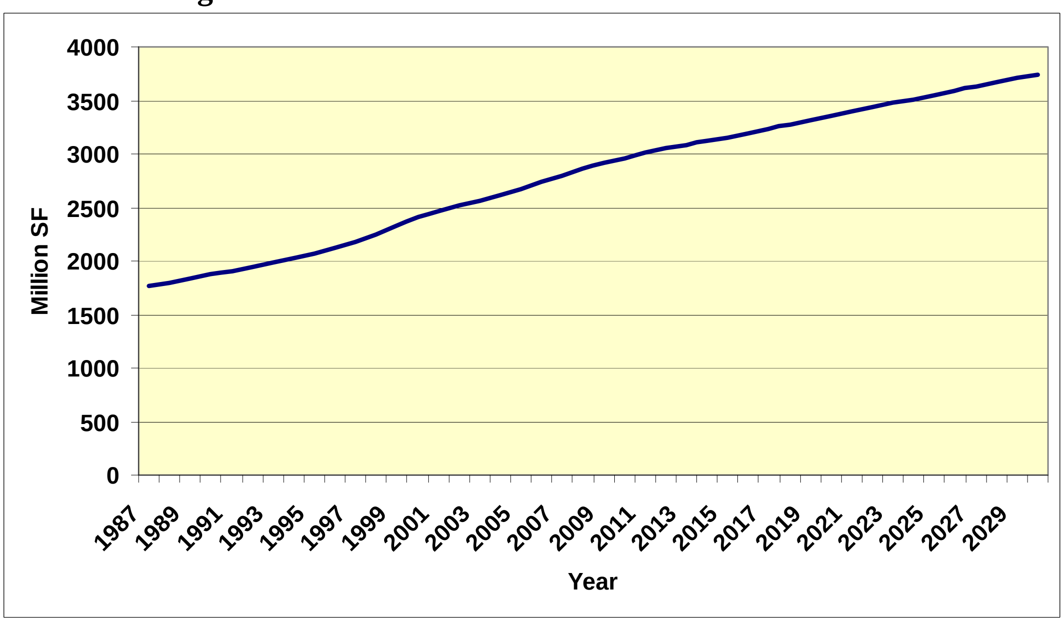
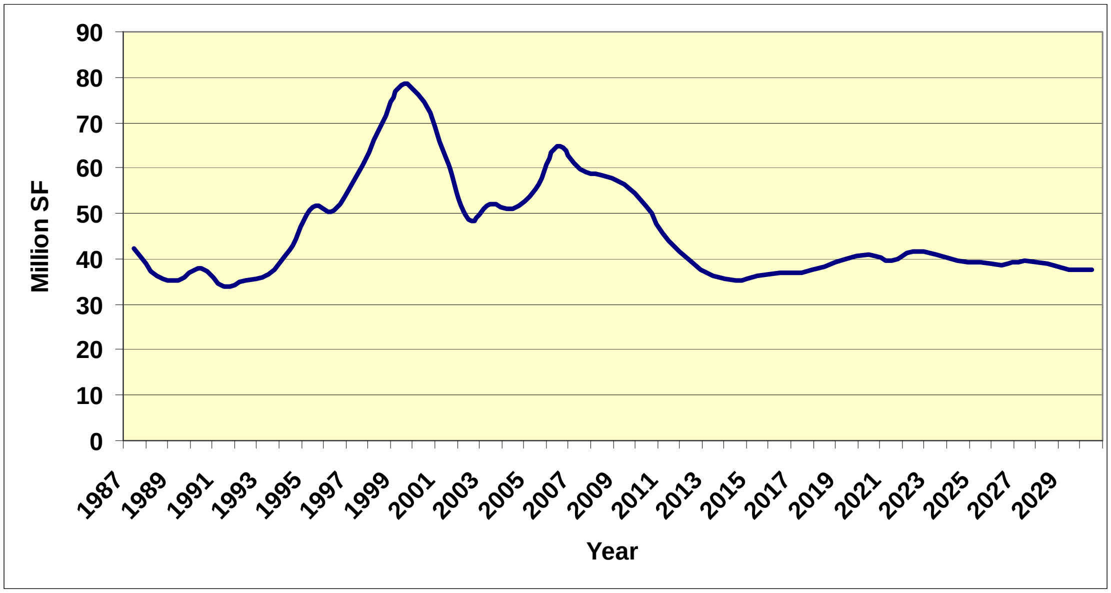


**Figure E-9: Annual Commercial Floor Area Additions 1987-2029**




## *Measure Bundles*

Over 250 individual commercial-sector measures are analyzed in the Sixth Power Plan. These measures are consolidated into 45 bundles of related measures. The measure bundles are chosen primarily for analytical expediency. For example, measures that reduce interior lighting power density (LPD) are bundled together. Measures that reduce lighting hours through occupancy sensors are bundled separately. Measures that reduce interior lighting through daylighting are also bundled separately. Measure bundles do not always correspond to the way measures are bundled for programmatic implementation.

Measures are also consolidated into three types of application modes. These modes are new, natural replacement and retrofit. The new mode applies primarily to new buildings or new equipment. The natural replacement mode applies to subsystems and equipment within buildings that are replaced on burnout, at the end of their useful life, or at the time of remodel of the building or system within a building. Retrofit mode is used where a measure or a building subsystem is replaced or retired before the end of its useful life.

There are three reasons to distinguish the new, natural replacement and retrofit application modes. First, costs and savings can be different by application mode. Second, in the case of new and natural replacement, the available stock for the measure depends on the forecast of new additions and replacement rate for equipment. These opportunities are tracked separately over course of the forecast period and limit the annual availability of conservation opportunities. Third, the Council's portfolio model treats new and natural replacement applications as lost-opportunity measures that can only be captured at the time of construction or natural replacement.

Measure costs, savings, applicability, and achievability estimates are identified separately for each of the new, natural replacement and retrofit application modes. The Council analyzes measure costs and savings on an incremental basis. Measure cost is the incremental cost over what would be done absent the measure or program. The same is true for savings. Incremental measure costs and savings can be different depending on the application mode. For example, incremental costs for high performance T8 fluorescent lamps and ballasts in a new application only include the additional cost above standard T8 lamps and ballast. But in a retrofit application, the cost of removing and disposing of existing tubes and ballast are added to the measure cost.

Table E-10 lists the commercial sector measure bundles, a short description of the measures, the number of measures in each bundle and the technical energy savings potential by 2029 in each bundle by application mode.

## Table E-10: Commercial Sector Measure Bundles

| Measure Bundle | End Use | Number of Measures in Bundle | Measure Description | Technical Potential in MWa by Year 2029 New | Natrual Replacement | Retrofit | Total |
|---|---|---|---|---|---|---|---|
| Lighting Power Density | Lighting | 54 | Lamp, ballast and fixture improvements to lighting power density | 51 | 354 | 38 | 443 |
| Daylighting with Skylights | Lighting | 6 | Skylights with lighting controls | 16 | 0 | 0 | 16 |
| Daylighting with Windows | Lighting | 6 | Perimeter daylighting controls | 3 | 12 | 0 | 15 |
| Lighting Controls Interior | Lighting | 6 | Occupancy controls for areas not required by code such as open office, warehouse aisle, classrooms | 6 | 65 | 8 | 79 |
| Exit Signs | Lighting | 2 | LED and electroluminescent "Exit" signs | 0 | 0 | 0 | 0 |
| Premium HVAC Equipment | HVAC | 4 | HVAC equipment more efficient than applicable code or standard practice | 8 | 31 | 0 | 39 |
| Variable Speed Chiller | HVAC | 2 | Variable speed chillers | 1 | 14 | 0 | 15 |
| Controls Commission Complex HVAC | HVAC | 20 | Commissioning on HVAC systems in buildings with complex HVAC systems | 10 | 0 | 124 | 134 |
| Package Roof Top Optimization and Repair | HVAC | 8 | Suite of measures and control strategies for buildings served by package roof top HVAC units | 4 | 8 | 16 | 29 |
| Low Pressure Distribution Complex HVAC | HVAC | 2 | Dedicated Outside Air or Underfloor Air distribution systems in buildings with complex HVAC systems | 6 | 0 | 0 | 6 |
| Demand Control Ventilation | HVAC | 5 | Fan control strategies, DCV and Fleet Strategy DOAS with heat recovery in simple HVAC systems | 4 | 4 | 14 | 22 |
| ECM Motors on Variable Air Volume Boxes | HVAC | 2 | Electically Commutated Motors on Variable Air Volume Boxes | 3 | 9 | 0 | 12 |
| Evaporative Assist Cooling | HVAC | 0 | Evaporative Assist Cooling | 0 | 0 | 0 | 0 |
| Windows | HVAC | 39 | Windows and glazing more efficiecnt that code or standard practice | 3 | 8 | 22 | 33 |
| Roof Insulation | HVAC | 2 | Add insulation during re-roofing | 0 | 3 | 0 | 3 |
| Duct Sealing and Repair | HVAC | 0 | Sealing and repair of ductwork in unconditioned spaces | 0 | 0 | 0 | 0 |
| Efficienct fans, pumps and drives | HVAC | 0 | Variable speed fans, pumps and drives, pump and fan system efficiencies and demand control | 0 | 0 | 0 | 0 |
| Exterior Building Lighting | Ext Lighting | 4 | Effiicient façade, walkway, area and decorative exterior lighting, such as LED | 0 | 67 | 0 | 67 |
| Integrated Building Design | Multi | 13 | Multiple measures applied in integrated design practice | 61 | 0 | 0 | 61 |
| Street and Roadway Lighitng | Ext Lighting | 2 | Efficient street and roadway lighting, LED and induction | 8 | 42 | 0 | 51 |
| Parking Lighting | Ext Lighting | 2 | Efficient parking lot and garage lighting and controls | 1 | 38 | 0 | 38 |
| LED Traffic Lights | Ext Lighting | 1 | LED traffic signals | 0 | 0 | 0 | 0 |
| Signage | Ext Lighting | 1 | LED advertizing signs | 0 | 5 | 0 | 5 |
| Municipal Sewage Treatment | Process | 10 | Suite of measures for sewage treatment | 0 | 0 | 27 | 27 |
| Municipal Water Supply | Process | 5 | Suite of measures for water supply systems | 0 | 0 | 13 | 13 |
| Network PC Power Management | Process | 1 | Control of a networked computer's advanced energy management systems | 0 | 0 | 40 | 40 |
| Packaged Refrigeration Equipment | Process | 20 | Efficient refrigerators and freezers, beverage merchandizers, ice makers and vending machines | 52 | 0 | 0 | 52 |
| Commercial Clothes Washers | Process | 0 | Clotheswashers more efficient than federal standard | 0 | 0 | 0 | 0 |
| Cooking Equipment | Process | 0 | Efficient cooking equipment such as hot food holders, grills, fryers and steam tables | 0 | 0 | 0 | 0 |
| Office Equipment | Process | 2 | Efficient Desktop PC and Efficient Monitor | 0 | 0 | 0 | 0 |
| Computer Servers and IT | Process | 2 | Consolidation & virtualization & upgrade of servers in embedded server rooms in buildings | 0 | 0 | 88 | 88 |
| DCV Restaurant Hood | Process | 1 | Demand control ventilation systems for large restaurant hoods | 0 | 0 | 4 | 4 |
| DCV Parking Garage | Process | 1 | Demand control ventilation systems for parking garages | 0 | 0 | 0 | 0 |
| Grocery Refrigeration Bundle | Process | 12 | Grocery store refrigeration measures | 0 | 0 | 68 | 68 |
| Plug Load Sensor | Process | 1 | Occupancy controls for task lighting and other ancillary loads in offices | 0 | 0 | 0 | 0 |
| Premium Fume Hood | Process | 1 | Effiicient fume hoods in labs | 21 | 0 | 0 | 21 |
| Pre-Rinse Spray Wash | Process | 1 | Low-flow pre-rinse spray valves for restaurant kitchens, cafeterias, and food-serving | 0 | 0 | 2 | 2 |
| **Total** | | **238** | | **258** | **662** | **462** | **1382** |

## *Overview of Methods*

Measure costs and savings are developed at a level of detail compatible with data availability, expected variance in measure costs and savings, the diversity of measure applications and practical limitations on the number of measures that can be analyzed. Costs and savings are based both on engineering estimates as well as estimates based on results from the operation of existing programs. Savings potential is the product of savings per unit and the forecast of number of units that the measure is applicable to. For most of the commercial sector measures, building floor area, by building type, is the primary unit of measure. Most measures apply to a fraction of the building stock in a particular building type. In addition to building floor area, several of the measure potential estimates are based on forecast of equipment stock, equipment turnover rates, equipment sales data, population, and process capacity.

For every measure or practice analyzed, there are four major methodological steps to go through. These steps establish baseline conditions, measure applicability, and measure achievability. For the commercial-sector conservation measures, each of these is treated explicitly for each measure bundle.

### Baseline Characteristics

Baseline conditions are estimated from current conditions for existing buildings and systems. Estimates of current conditions and characteristics of the building stock come from several sources. Key among these are the Pacific Northwest Commercial Building Stock Assessment (CBSA), the national Commercial Building Energy Consumption Survey (CBECS), market research projects of the Northwest Energy Efficiency Alliance (NEEA), selected studies from utilities, Energy Trust of Oregon, and other sources.

For new buildings, new and replacement equipment, baseline conditions are estimated from a combination of surveys of new buildings, state and local building energy codes and federal and state appliance efficiency standards. The most recent survey data used is from the NEEA New Buildings Characteristics study completed in 2008 which looked at buildings built in the 2002-2004. Codes and standards are continually being upgraded. The baseline assumptions used in the Sixth Power Plan are those that were adopted at the end of 2008, with a few exceptions. Some of these include standards that are adopted now but with effective dates that occur in the future. For such codes or standards, both savings estimates and the demand forecast reflect the effective dates of adopted standards.

### Measure Applicability

Measure applicability reflects several major components. First is the technical applicability of a measure. Technical applicability includes what fraction of the stock the measure applies to. Technical applicability can be composed of several factors. These include the fraction of stock that the measure applies to, overlap with mutually exclusive measures and the existing saturation of the measure. Existing measure saturation reflects the fraction of the applicable stock that has already adopted the measure and for which savings estimates do not apply. There are hundreds of applicability assumptions in the conservation assessment. Applicability assumptions and source references are detailed in the workbooks for each measure bundle.

## Measure Achievability

The Council assumes that only a portion of the technically available conservation can be achieved. Ultimate achievability factors are limited to 85 percent of the technically available conservation over the twenty-year forecast period. In addition to a limit of 85 percent, the Council considers near-term achievable penetration rates for bundles of conservation measures. Several factors are used to estimate near-term achievability rates. Recent experience with region wide conservation program accomplishments is one key factor. But in addition to historic experience, the Council also considers a bottom-up approach to estimate near-term achievability.

In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described and consideration of likely delivery mechanisms. This detailed bottom-up approach is a new element in the Sixth Power Plan. In the Sixth Plan, the Council uses a suite of typical ramp rates to reflect near-term penetration rates. For example, measures involving emerging technology might start out at low penetration rates and gradually increase to 85 percent penetration. Measures suitable for implementation by a building code or a federal equipment standard might increase rapidly to 85 percent penetration in new buildings and major remodels. Measures requiring new delivery mechanisms might ramp up slowly. Simple measures with well-established delivery channels, like efficient shower heads, might take only half a dozen years to fully implement. Whereas retrofit measures in complex markets might take 20 years to reach full penetration.

Assumptions for the bottom-up approach are detailed in the conservation supply curve workbooks. The worksheet "ACHIEV" in the workbook ComMaster contains all the achievability assumptions by measure bundle.

## Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on. In the commercial sector analysis, the applicable units' estimates come from several sources. For measures in buildings, the units are primarily floor area with applicable characteristics. These data come primarily from the Commercial Building Stock Assessment (CBSA). For some of the equipment measures, additional unit data from utility surveys of characteristics, national data from Commercial Building Energy Consumption Survey (CBECS), equipment sales data, census data, and many others.

The estimates of physical units available include the number of units available annually. For example, for new buildings, the estimate of available new building stock is taken from the Council's baseline forecast for annual additions by building type. Similarly for equipment replacement measures the annual stock available is taken from estimates of the turnover rate of the equipment in question. For retrofit measures, the annual stock availability is a fraction of the estimated stock remaining at the end of the forecast period. The estimates of physical units available are called stock models and are embedded in the measure bundle workbooks. The worksheets that contain the stock models are identified by the prefix "SC".

## *Guide to the Commercial Conservation Workbooks*

There are about 50 Excel workbooks used to develop the commercial-sector conservation assessment. In addition there are dozens of outside sources of data which are referenced. The Council workbooks are available from the Council website.[9] Supporting data sources are identified in the workbooks and the key supporting data from these sources is summarized in the Council workbooks. All outside source data is cited in the workbooks or otherwise made available to the extent it is not proprietary.

Figure E-10 describes the main components and structure of the commercial conservation assessment workbooks. The workbooks and brief descriptions of their purpose are listed in Table E-11.

[9] http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm

## Figure E-10: Main Components and Structure of the Commercial Conservation Assessment Workbooks

**ProCost Measure Workbooks:** These workbooks contain the detailed analysis for all the measures. Generally there is one workbook for each bundle of similar or related measures.

Naming convention starts with PC (For example: PC-ECMVAV-6P-D1.xls means is the ProCost workbook for the measure Electronically Commutated Motors on VAV systems, 6th Plan, Draft 1)

These files contain the ProCost engine used for cost-effectiveness analysis. They also contain the supporting analysis of measure cost and savings as well as links to data used to support the analysis. They also contain supply curves for the measure bundle.

Basic layout as follows:

<u>SC worksheets:</u> Calculates supply curve total savings potential by cost bin by year. Uses output data from MData worksheets along with unit forecasts from floor space sheet and achievability rates from ComMaster. Usually there are several SC worksheets for new, retrofit and natural-replacement applications since cost and savings and units are different for each application.

<u>ProData worksheet:</u> Control panel for ProCost analysis.

<u>MData worksheets:</u> Measure data sheets. Measure level inputs and outputs for ProCost. Normalized to floor area with one to several hundred permutations of costs and savings. At least two permutations of the MData tab exist in each sheet. One is for the "measure" level which represent costs and savings for an individual measure. This provides the cost and savings estimates for individual measures regardless of the measure's applicability. The other is the "regional" level which includes costs and savings weighted for applicability across the region. ProCost output by measure ends up here too and is passed to the supply curve sheets to develop supply curves. Inputs to MData are usually harvested from MMap tab.

<u>MMap worksheet:</u> Measure Map. Used to assign costs and savings inputs to each application and permutation of the measure. Feeds MData worksheets.

<u>Notes and Sources worksheet</u> Contains notes, savings calculations and links to sources.

<u>Supporting worksheets</u>: A variety of supporting worksheets, documentation and administrative notes are also included.

<u>6PSummary:</u> Summarizes key input assumptions, sources and calculation methodology.

ComMaster

Contains measure list, links to all supporting files and sheets for other administrative functions.

Contains key characteristics common among measures used to calculate savings estimates. Includes measure applicability (APPLIC), baseline penetration (BASE), applicable vintage cohort (STOCK), achievability rates (ACHIEV), fuel saturations, equipment saturations and other key characteristics (CHAR) used in the analysis by building occupancy type and application (New, Retro or Natural Replacement (NR)) . Also includes common variables, labels (VAR & Labels) and other administrative functions.

ComFloorAreaForecast.xls (or similar name)

Output from regional forecast model. Supply curve estimates are driven primarily by floor space estimates, equipment count or population. File contains stock estimates relevant to the measures by building occupancy type, state and vintage.

MC_AND_ LOADSHAPE

Contains avoided cost and shape of savings data. Called by ProCost.

SUPPLYCURVEBUNDLER

Bundles all measures into supply curves by cost bin and year for input to portfolio model.

**Table E-11:  List of Commercial-Sector Workbooks**

| File Name | File Description |
|---|---|
| **Com_Master** | Master Workbook for Commercial Sector Conservation |
| **ComLighting_v2008-D2** | Support file for lighting power density measure workbook |
| **Commercial Forecast 6P** | Floor area and population forecast |
| **InteractionsBldgType01082004-** | Space Heat and Cooling Interaction Factors for Lighting Savings |
| **MC_AND_LOADSHAPE_6P** | Marginal Cost and Load Shape Data File |
| **PC-Cooking-6P-D1** | Measure workbook:  Cooking |
| **PC-DCVGarage-6P-D1** | Measure workbook:  Demand Control Ventilation Parking Garage |
| **PC-DCVHood-6P-D1** | Measure workbook:  Demand Control Ventilation Restaurant |
| **PC-DemandControlVent-6P-D4** | Measure workbook:  Demand Control Ventilation for HVAC |
| **PC-DuctSeal-6P-D1** | Measure workbook:  Duct Sealing |
| **PC-ECMVAV-6P-D4** | Measure workbook:  ECM Motors in Variable Air Volume HVAC |
| **PC-EvapAssist-6P-D1** | Measure workbook:  Evaporative Assist Cooling |
| **PC-Exit Sign-6P-D2** | Measure workbook:  Exit Signs |
| **PC-ExtLight-6P-D1** | Measure workbook:  Exterior Building Lighting |
| **PC-FanPumpDrive-6P-D1** | Measure workbook:  Adjustable Drives for Fans & Pumps |
| **PC-FumeHood-6P-D1** | Measure workbook:  Efficient Lab Fume Hood |
| **PC-Grocery-6P-D3** | Measure workbook:  Grocery Store Measures |
| **PC-HVACControls-6P-D4** | Measure workbook:  Controls Commission Complex HVAC |
| **PC-HVACEQUIP-6P-D7** | Measure workbook:  Premium HVAC Equipment |
| **PC-IntDesign-6P-D1** | Measure workbook:  Integrated Building Design |
| **PC-Lighting Controls Interior-6p-** | Measure workbook:  Lighting Controls Interior |
| **PC-Lodging-6P-D1** | Measure workbook:  Lodging-Specific Measures |
| **PC-LowPressureDist-6P-D1** | Measure workbook:  Low Pressure Distribution Complex HVAC |
| **PC-LPDPackage-6P-D16** | Measure workbook:  Lighting Power Density Interior |
| **PC-NetworkPC Power** | Measure workbook:  Network PC Power Management |
| **PC-OfficeEquip-6P-D1** | Measure workbook:  Office Equipment |
| **PC-Pack Refrig Equip-6P-D3** | Measure workbook:  Refrigerators, freezers, ice makers, |
| **PC-PackRTOptimize-6P-D6** | Measure workbook:  Package Roof Top Optimization and Repair |
| **PC-Parking Lighting-6P-D1** | Measure workbook:  Parking Lighting |
| **PC-PlugLoadSensor-6P-D1** | Measure workbook:  Plug Load Sensor |
| **PC-ReRoof-6P-D1** | Measure workbook:  Roof Insulation |
| **PC-ServerRooms and IT-6P-D1** | Measure workbook:  Computer Server Room Efficiency |
| **PC-SideDaylight-6P-D1** | Measure workbook:  Day Lighting Control - Windows |
| **PC-Singage-6P-D1** | Measure workbook:  LED Signage |
| **PC-Spray Head-6P-D1** | Measure workbook:  Pre-Rinse Spray Valve |
| **PC-StreetRoadway-6P-D2** | Measure workbook:  Street and Roadway Lighting |
| **PC-TopDaylightNew-6P-D5** | Measure workbook:  Day Lighting Control - Skylights |
| **PC-Traffic Signals-6P-D1** | Measure workbook:  LED Traffic Signals |
| **PC-VSDChiller-6P-D3** | Measure workbook:  Variable Speed Chillers |
| **PC-Wastewater-6P-D1** | Measure workbook:  Municipal Wastewater |
| **PC-WaterSupply-6P-D3** | Measure workbook:  Municipal Water Supply |
| **PC-Windows-6P-D10** | Measure workbook:  Windows |
| **ProCostFinAssumptions_Sector** | Financial Assumptions |
| **SupplyCurveBundlerLO** | Bundles all Lost-Opportunity Measures into Supply Curves |
| **SupplyCurveBundlerRetro** | Bundles all Retrofit Measures into Supply Curves |

The main workbook is named ComMaster.  ComMaster contains the master measure list, the measure bundles, common assumptions used throughout the analysis and links to the ProCost measure files where detailed measure-specific analysis resides. The reference data in ComMaster are primarily in matrices by measure bundle and building type. The reference data in the ComMaster file are listed and described in Table E-12.

**Table E-12: Reference Data in ComMaster Workbook**

| Sheet Name | Contents |
|---|---|
| Overview | Overview of model structure |
| MLIST | Master List of measure bundles |
| FILES | List and links to measure-level files. Plus housekeeping. |
| APPLIC | Applicability factor for the measure. Fraction of stock the measure applies to. |
| BASE | Baseline penetration of measure. Estimated fraction of stock where the measure is already in place. |
| STOCK | Vintage cohort that the measure applies to. |
| TURN | Turnover rate for stock to which measure applies. |
| ACHIEVE | Achievable rate of acquisition for measure bundles by year |
| CODE | Tables developed to estimate regional baseline penetration for various elements of energy codes by jurisdiction |
| CHAR | Key characteristics for stock by vintage cohort and building subtype. Used to develop regional application of meas |
| FLOOR | Floor area forecast summary used to develop data in CHAR |
| VARS | List of variables used in the CHAR tab and elsewhere in the files. |
| Labels | Map of building types labels from different sources. |
| Lookup | Lookup table for vintage cohort |
| EUI | Reference EUI from various sources including CBECS & CBSA. |

# INDUSTRIAL SECTOR

## *Overview*

The Sixth Plan Industrial Supply Curve (ISC) conservation assessment was prepared by a contractor, Strategic Energy Group (SEG) with guidance from Council staff and an advisory group. The assessment includes an Excel workbook, referred to as the Measure Analysis Tool, which contains industrial load data, measure data, conservation supply curves and documentation. There is another Excel workbook, referred to as the NPCC Supply Curve Generator, which converts measure costs and savings data to conservation supply curves for input to the Council's Resource Portfolio Model. The contractor also prepared documentation of the development of the analysis, the Measure Analysis Tool, and a detailed description of the modeling of a subset of the measures referred to as System Optimization Measures.

In addition to these major components, the assessment includes a rich dataset of sources referred to as the Industrial Data Catalogue and a guide to that catalogue. Finally, the project also developed a detailed database on motor loads at industrial facilities in the Northwest. This is called the Northwest Industrial Motor Database.

## *Industrial Sector Overview and Coverage*

The Council's industrial sector analysis covers most of the region's non-DSI industries plus refrigerated warehouse storage. The assessment does not include savings estimates for the direct-service industries. Nor does it cover savings potential in the information technology sector (IT). These two subsectors were beyond the scope of the industrial assessment.

## *Structure of the Analysis*

The conservation assessment model is structured differently that the Council's assessments in other sectors. The ISC model uses estimates of energy savings as a fraction of load by end use by industry.

First, data were collected on electricity use by industry by state. These data came from a variety of sources primarily utility-provided reports. But other sources were considered too including data supplied by individual plants, proprietary datasets and publicly-available data. These data were calibrated to industrial load data reported by state to EIA. Then the consumption estimates were split into estimates of electricity use by major process end use. Then energy conservation measures (ECMs) are applied to the use by end use estimates as a percent savings with associated costs. Finally, factors for measure applicability, measure interaction, and achievability rates over time are applied. A detailed summary of the structure of the assessment is available in the document entitled "ISC Model Review R4".

## *Guide to the Industrial Sector Workbooks and Data*

Table E-13 identifies the key workbooks and files that comprise the industrial conservation assessment.

**Table E-13: List of Industrial Sector Workbooks**

| Item | Description |
|---|---|
| **Measure Analysis Tool** | Excel workbook containing the major elements of the industrial sector characterization, the estimates of end use splits and the details on the energy conservation measures |
| **Description of Measure Analysis Tool** | Description of the structure and development of the Measure Analysis Tool |
| **NPCC Supply Curve Generator** | Excel workbook which translates the costs and savings from the Measure Analysis Tool into supply curve data for the Regional Portfolio Model. Uses ProCost to develop TRC Net levelized costs consistent with estimates in other sectors |
| **Documentation on System Optimization Measures** | Excel workbook containing detailed derivation of costs, savings and measure applicability for a suite of measures related to system optimization of key industrial processes |
| **Systems Whole Plant Optimization Overview** | Description of the system optimization and whole plant measure bundles, the input assumptions, and supporting sources |
| **Industrial Data Catalogue and Guide** | Large database of industrial data sources. A compilation of published and unpublished resource assessments, market and technology reports, datasets, case studies and guidebooks focused on industrial energy efficiency and energy management. The files include N electronic collection of these resources |
| **Northwest Industrial Motor Database** | Information on motors that collected over 20 years by the Industrial Assessment Center (IAC) at Oregon State University (OSU). The Northwest Industrial Motor Database includes a database of a total of 22,514 records, each with detailed motor application data. |

# AGRICULTURAL SECTOR

## *Overview*

The Sixth Power Plan's assessment of conservation potential in the agriculture sector covers irrigation hardware system efficiency improvements, irrigation water management (scientific irrigation scheduling) and diary farm milk processing. Consistent with the conservation assessments in prior plan's the largest potential savings in the agriculture sector are available through irrigation hardware system efficiency improvements, including reducing system operating pressures, reducing system leaks and improving pump efficiency. The next largest savings in this sector come from improved water management practices followed by dairy milk processing savings. This is the first Council plan to estimate savings from irrigation water management and diary milk production.

## *Measure Bundles*

Seven generic irrigation hardware system efficiency improvements and three "operation and maintenance" (e.g., gasket and nozzle replacement) measures are analyzed in the Sixth Power Plan. Irrigation water management practices were considered as a bundled measure consisting of moisture monitoring hardware and software. Four individual, non-interactive measures were considered for improving the energy efficiency of dairy milking barns and milk processing.

## *Overview of Methods*

The irrigation hardware efficiency measures were evaluated using savings derived from an engineering spreadsheet model that simulates the energy use of a center pivot system using alternative pump efficiencies, static and dynamic head, annual water throughput and system leakage rates. Each hardware efficiency measure's savings were estimated based on water supplied by a well of average depth and water supplied by a deep well for each of the Northwest states. Data on well depth, amount of water applied, average pump size and irrigated acreage served by each type of irrigation system were drawn from the most recent USDA Farm and Ranch Survey. All data used from this survey are shown in the "IrrgAgHardwareSupplyCurve_6Pv1_1.xls."

Irrigation water management savings were estimated using a spreadsheet developed by the Columbia Basin Ground Water Management Association (GAMA). This spreadsheet was modified to reflect the average water savings achieved in Bonneville's evaluation of irrigation water management. This evaluation documented the average water savings from scientific irrigation water management as well as the cost of carrying out improved practices. Dairy efficiency improvements were based on detailed audits and retrofits of 30 dairies in New York carried our by the New York State Energy Research and Development Administration (NYSERDA).

### Baseline Characteristics

Baseline conditions for irrigation hardware system efficiency improvements were estimated from the USDA Farm and Ranch survey and discussions with Bonneville and utility staff with in-depth experience working with farmers on these systems. Baseline characteristics (i.e., the average amount of water applied by crop type and acreage) for irrigation water management in the Columbia Basin Project was provided by GAMA. Dairy efficiency in the region was assumed to parallel that found by NYSERDA.

### Measure Applicability and Measure Achievability

No quantitative study has been conducted in the region to determine the current saturation and remaining opportunities for improvement in either irrigation system hardware or on diaries. Therefore, judgment, based on discussions with Bonneville and utility program staff served as the basis estimating the remaining number of systems and diaries in the region that could carry out cost-effective energy efficiency improvements. Where quantitative data was available (e.g. the acreage irrigated with high pressure systems) this data was used to size the remaining opportunities for savings.

### Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on. In the irrigation sector analysis, the applicable unit estimates for irrigated acreage, system types and annual water application were drawn from the USDA Farm and Ranch Survey. GAMA provided data on the acreage and crop types present in Columbia Basin Project. The estimate of current diary production in the region also comes from the USDA and the US Department of Commerce. Staff developed a forecast of future milk production growth in the region using historical trends.

The three workbooks containing the Agriculture Sector conservation resource assessment are downloadable from the web. These are:

- Irrigation Hardware System Efficiency Improvements - IrrgAgHardwareSupplyCurve_6Pv1_1.xls
- Irrigation Water Management - SIS_SupplyCurve_6thPlanv1_1.xls
- Diary Efficiency Improvement - DairySupplyCurve_6thPlanv1_1.xls

# DISTRIBUTION SYSTEM

## *Overview*

The Sixth Power Plan includes a conservation potential assessment on the region's electric distribution system. The assessment is based on a study completed in 2007 by R.W. Beck for the Northwest Energy Efficiency Alliance (NEEA).

## *Structure of the Analysis*

The distribution system conservation assessment uses savings estimates from measured data on 33 utility feeders, and analytical methods developed by RW Beck in the NEEA study. Costs and savings for four major measures were identified and applied to a descriptive data set of the region's distribution system. The dataset contains system loads by customer class, substation counts, feeders counts, customer counts and climate zones for 137 regional utilities used to generate the units estimates. Table E-14 below identifies the key workbooks and data used in the analysis.

Table E-14 identifies the key workbooks and files that comprise the distribution system conservation assessment.

**Table E-14: List of Agriculture Sector Workbooks**

| Item | Description |
|---|---|
| **NPPC Supply Curve** | Excel workbook used to generate the supply curves with documentation |
| **Supporting Data** | Excel workbook containing the data on distributions systems and the key factors for the savings estimates |
| **Distribution Efficiency Initiative** | 2007 RW Beck Study for NEEA. Findings from this study were used to develop the conservation supply curves |

# Appendix F: Model Conservation Standards

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## 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 ELECTRONICALLY 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

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

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 all 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. 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:

## *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 E-1 for 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 E-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.

[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.]

[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: 6,000-7,499 heating degree days; and Zone 3: over 7,500 heating degree days.

## *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. 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 Model Conservation Standard for New Site Built Electrically Heated Residential Buildings**

| | Climate Zone | | |
|---|---|---|---|
| **Component** | **Zone 1** | **Zone 2** | **Zone 3** |
| **Ceilings** | | | |
| • Attic | R-49 (U-0.020)[a,b] | R-49 (U-0.020)[a,b] | R-49 (U-0.020)[a,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-21 | R-21 | R-21 |
| **Floors** | | | |
| • Crawlspaces and Unheated Basements | R-30 (U-0.029) | R-30 (U-0.029) | R-30 (U-0.029) |
| • Slab-on-grade - Unheated[e] | R-10 Full Under Slab | R-10 Full Under Slab | R-10 Full Under Slab |
| • Slab-on-grade - Heated | R-10 Full Under Slab w/R-5 Thermal Break | R-10 Full Under Slab w/R-5 Thermal Break | R-10 Full Under Slab w/R-5 Thermal Break |
| Glazing[f,g] | R-3.33 (U-0.30) | R-3.33 (U-0.30) | R-3.33 (U-0.30) |
| Exterior Doors | R-5 (U-0.19) | R-5 (U-0.19) | R-5 (U-0.19) |
| Thermal Infiltration Rate[h] | 0.35 ach | 0.35 ach | 0.35 ach |
| Ventilation and Indoor Air Quality[i] | ASHRAE Standard 62.2-2007 with Heat Recovery Ventilation | | |
| Service Water Heater[j] | Energy Factor = 2.2 | | |
| Hardwired Lighting | Maximum Lighting Power Density - 0.6 Watts/sq.ft. | | |
| Space Conditioning System | Minimum Heating Season Performance Factor (HSPF) - 9.0<br>Minimum Seasonal Energy Efficiency Rating (SEER) - 14.0 | | |

[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 all zones shall be framed using techniques to ensure full insulation depth to the exterior of the wall. Attics in multifamily buildings in all zones 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] Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values. Reference case glazing area equal to15 percent of conditioned floor area shall be used in thermal envelope component tradeoff calculations.

[h] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage without heat recovery ventilation..

[i] The dwelling shall have a heat recovery mechanical ventilation system that is sized to comply with the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62.2-2007*, Ventilation and Acceptable Indoor Air Quality in Low-rise Residential Buildings.*

.[j] Water Heater Energy Factor (EF) varies by tank capacity. EF shown is for 50 gallon nominal tank capacity. EF may be adjusted higher or lower based on actual nominal water heater tank capacity.

**Table F-2: Illustrative Paths for the Model Conservation Standard for New Electrically Heated Manufactured Homes**

| | Climate Zone | | |
|---|---|---|---|
| **Component** | **Zone 1** | **Zone 2** | **Zone 3** |
| **Ceilings** | | | |
| • Attic | R-49[a] (U-0.023) | R-49 (U-0.023) | R-49 (U-0.023) |
| • Vaults | R-38 (U-0.030) | 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,c] | R-3.33 (U-0.30) | R-3.33 (U-0.30) | R-3.33 (U-0.30) |
| Exterior Doors | R-5 (U-0.19) | R-5 (U-0.19) | R-5 (U-0.19) |
| Thermal Infiltration Rate[d] | 0.35 ach | 0.35 ach | 0.35 ach |
| Overall Conductive Heat Loss Rate (Uo) | 0.047 | 0.047 | 0.047 |
| Ventilation and Air Quality[e] | ASHRAE Standard 62.2-2007 | | |
| Service Water Heater[f] | Energy Factor = 2.2 | | |
| Hardwired Lighting | Maximum Lighting Power Density - 0.6 Watts/sq.ft. | | |
| Space Conditioning System | Minimum Heating Season Performance Factor (HSPF) - 9.0<br>Minimum Seasonal Energy Efficiency Rating (SEER) - 14.0 | | |

[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] Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values. Reference case glazing area equal to15 percent of conditioned floor area shall be used in thermal envelope component tradeoff calculations.

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

[e] The dwelling shall have a heat recovery mechanical ventilation system that is sized to comply with the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62.2-2007, *Ventilation and Acceptable Indoor Air Quality in Low-rise Residential Buildings.*

[f] Water Heater Energy Factor (EF) varies by tank capacity. EF shown is for 50 gallon nominal tank capacity. EF may be adjusted higher or lower based on actual nominal water heater tank capacity.

## *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 90.1-2007, 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 90.1-2007 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 90.1-2007 -- Energy Standard for Buildings Except Low-Rise Residential Buildings (IESNA cosponsored; ANSI approved; Continuous Maintenance Standard), I-P Edition and addenda 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.

## *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.

## *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.

## *Conservation Programs not Covered by Other Model Construction 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, because of the current economic conditions, some utilities are experiencing significantly slower or negative load growth. Investments in conservation, like any other resource acquisition, will increase utility cost and place additional upward pressure on rates. Furthermore, there is some uncertainty regarding how public utilities will respond to Bonneville's implementation of rate designs that will result in at least some portion of their loads exposed to cost of new resources. Bonneville has committed to ensure that the "public system" meet its share of the Sixth Plan's conservation targets. It is working with its customers to put in place programs and rate structures that designed to achieve this objective. However, should an individual utility fail to meet its share of the regional conservation goal, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customer's rates to recover those costs.

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.

[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.

# Appendix G: MCS Cost-effectiveness for Residences

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## INTRODUCTION

This appendix provides an overview of the method and data used to evaluation the regional cost-effectiveness and consumer economic feasibility of the Council's Model Conservation Standards for New Electrically Heated 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 | R30 | 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) | R21 | Not Applicable |
| Slab-below-Grade (F-Value/lin.ft. perimeter) | R10 | Not Applicable |
| Window | Class 35 (U<0.35) | 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 and cost estimates provided to the Regional Technical Forum based on program data from the Energy Trust of Oregon and Mission Valley Power.[2] These costs were converted to year 2006 dollars using the GDP Deflator. Costs include a 20 percent markup for builder overhead and profit. Table G-2 provides a summary of the incremental costs used in the analysis for site built homes.

[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.

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

| Conservation Measure | Incremental Installed Cost (2006$/sq.ft.) |
|---|---|
| Wall R19 Standard Framing | Base |
| Wall R21 Advanced Framing | $0.15 |
| Wall R21 Standard Framing + R5 Foam | $0.87 |
| Wall R30 Stressed Skin Panel | $1.19 |
| Wall R38 Double Wall | $0.61 |
| Attic R38 Standard Framing | Base |
| Attic R49 Advanced Framing | $0.39 |
| Attic R60 Advanced Framing | $0.39 |
| Vault R30 (Joisted) | Base |
| Vault R38 (Joisted w/High Density Insulation) | $0.62 |
| Vault R50 Stressed Skin Panel | $2.18 |
| Underfloor R30 | Base |
| Underfloor R38 (Truss joist) | $0.41 |
| Window Class 35 (U<0.35) | Base |
| Window Class 30 (U<0.30) | $0.89 |
| Window Class 25 (U<0.25) | $2.00 |
| Exterior Door R5 | Base |
| Slab-On-Grade R10 Perimeter, down 2 ft | Base |
| Slab-On-Grade R10 Perimeter, down 4 ft | $.27 |
| Slab-On-Grade R10 Full Under Slab w/R5 TB | $0.81 |
| Below-Grade Wall R21 Interior | Base |
| Below-Grade Wall R21 Interior + R5 Foam | $0.87 |

Cost for new manufactured home energy efficiency improvements were obtained from regional manufacturers, insulation and window.[3] Table G-3 summarizes this same information for manufactured homes. These costs 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.

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

| Conservation Measure | Incremental Installed Cost (2006$/sq.ft) |
|---|---|
| Wall R19 Standard Framing | Base |
| Wall R21 Standard Framing | $0.17 |
| Attic R19 | Base |
| Attic R25 | $0.10 |
| Attic R30 | $0.10 |
| Attic R38 | $0.15 |
| Attic R49 | $0.23 |
| Vault R19 | Base |
| Vault R25 | $0.10 |
| Vault R30 | $0.10 |
| Vault R38 | $0.15 |
| Underfloor R22 | Base |
| Underfloor R33 | $0.18 |
| Underfloor R44 | $0.18 |
| Window Class 35 (U<0.35) | Base |
| Window Class 30 (U<0.30) | $0.89 |
| Window Class 25 (U<0.25) | $2.00 |
| Exterior Door R5 | $4.54 |

## *Energy Use Assumptions*

The Council used an engineering simulation model, SEEM©, that is an improved version of the SUNDAY© simulation that has been calibrated to end-use metered space heating for electrically heated homes built across the region.[4]  Thermal shell 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 SEEM© simulation model was then used to estimate the space heating and space cooling 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** | 1344 sq.ft. | 2200 sq.ft. | 2268 sq.ft. | 924 sq.ft. | 1568 sq.ft. | 2352 sq.ft. |
| **Attic** | 1344 | 1784 | 1344 | 924 | 1568 | 2352 |
| **Door** | 40 | 40 | 40 | 40 | 40 | 40 |
| **Floor over Crawlspace** | 1,344 | 1,784 | 0 | 924 | 1,568 | 2,352 |
| **Volume** | 10,752 | 18,700 | 22,848 | 7,392 | 12,544 | 18,816 |
| **Slab-on-Grade (F-Value/lin.ft. perimeter)** | - | - | 140 | - | - | - |
| **Wall (Above Grade)** | 969 | 1,805 | 1,064 | 1,125 | 1,108 | 1,234 |
| **Wall Below Grade (Interior)** | - | - | 962 | - | - | - |
| **Slab-below-Grade (F-Value/lin.ft. perimeter)** | - | - | 148 | - | - | - |
| **Window** | 175 | 365 | 376 | 116 | 196 | 294 |

Five locations, Seattle, Portland, Boise, Spokane and Kalispell were selected to represent the range of climates found across the region. The SEEM© simulation model was run using the most recent (version 3) Typical Meteorological Year weather files for each of these locations. 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 | Kalispell |
|---|---|---|---|---|---|
| **Heating Zone 1** | 20% | 50% | 15% | 15% | 0% |
| **Heating Zone 2** | 0% | 0% | 10% | 85% | 5% |
| **Heating Zone 3** | 0% | 0% | 0% | 0% | 100% |

In order to determine whether a measure is regionally cost-effective the Council then compared the 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 G-6 through G-8 show the results of the cost-effectiveness analysis for each heating climate zone for site built homes and Tables G-9 through G-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 | | | | 2688 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** |
| WINDOW CL30 | 298 | 156 | 1.7 | WINDOW CL30 | 644 | 326 | 1.7 | WINDOW CL30 | 644 | 336 | 1.7 |
| INFILTRATION @ 0.20 ACH w/HRV | 1027 | 672 | 1.4 | INFILTRATION @ 0.20 ACH w/HRV | 1784 | 1100 | 1.4 | INFILTRATION @ 0.20 ACH w/HRV | 2281 | 1344 | 1.5 |
| ATTIC R49 ADVrh | 524 | 520 | 0.9 | ATTIC R49 ADVrh | 723 | 690 | 0.9 | ATTIC R49 ADVrh | 602 | 520 | 1.0 |
| WINDOW CL25 | 321 | 349 | 0.8 | WINDOW CL25 | 713 | 730 | 0.9 | SLAB R10-FULL | 1078 | 1088 | 0.9 |
| WALL R21 INT+R5 | 749 | 988 | 0.7 | WALL R21 INT+R5 | 1459 | 1840 | 0.7 | WINDOW CL25 | 729 | 753 | 0.9 |
| FLOOR R38 STD w/12"Truss | 335 | 552 | 0.5 | FLOOR R38 STD w/12"Truss | 454 | 733 | 0.5 | BGWALL R21 | 117 | 146 | 0.7 |
| ATTIC R60 ADVrh | 138 | 520 | 0.2 | ATTIC R60 ADVrh | 190 | 690 | 0.2 | WALL R21 INT+R5 | 802 | 1084 | 0.7 |
| WALL 8" SSPANEL | 213 | 1150 | 0.2 | WALL 8" SSPANEL | 382 | 2142 | 0.2 | ATTIC R60 ADVrh | 121 | 520 | 0.2 |
| WALL R33 DBL | 24 | 590 | 0.0 | WALL R33 DBL | 45 | 1099 | 0.0 | WALL 8" SSPANEL | 199 | 1262 | 0.1 |
| | | | | | | | | WALL R33 DBL | 25 | 647 | 0.0 |

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

| 1344 sq. ft | | | | 2200 sq. ft | | | | 2688 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** |
| WINDOW CL30 | 392 | 156 | 2.2 | WINDOW CL30 | 830 | 326 | 2.3 | WINDOW CL30 | 836 | 336 | 2.2 |
| INFILTRATION @ 0.20 ACH w/HRV | 1349 | 672 | 1.8 | INFILTRATION @ 0.20 ACH w/HRV | 2309 | 1100 | 1.9 | INFILTRATION @ 0.20 ACH w/HRV | 2956 | 1344 | 1.9 |
| ATTIC R49 ADVrh | 692 | 520 | 1.2 | ATTIC R49 ADVrh | 940 | 690 | 1.2 | ATTIC R49 ADVrh | 762 | 520 | 1.3 |
| WINDOW CL25 | 402 | 349 | 1.0 | WINDOW CL25 | 878 | 730 | 1.1 | SLAB R10-FULL | 1331 | 1088 | 1.1 |
| WALL R21 INT+R5 | 933 | 988 | 0.8 | WALL R21 INT+R5 | 1805 | 1840 | 0.9 | WINDOW CL25 | 900 | 753 | 1.1 |
| FLOOR R38 STD w/12"Truss | 435 | 552 | 0.7 | FLOOR R38 STD w/12"Truss | 594 | 733 | 0.7 | BGWALL R21 | 144 | 146 | 0.9 |
| ATTIC R60 ADVrh | 183 | 520 | 0.3 | ATTIC R60 ADVrh | 251 | 690 | 0.3 | WALL R21 INT+R5 | 1025 | 1084 | 0.8 |
| WALL 8" SSPANEL | 289 | 1150 | 0.2 | WALL 8" SSPANEL | 519 | 2142 | 0.2 | ATTIC R60 ADVrh | 162 | 520 | 0.3 |
| WALL R33 DBL | 33 | 590 | 0.0 | WALL R33 DBL | 61 | 1099 | 0.0 | WALL 8" SSPANEL | 272 | 1262 | 0.2 |
| | | | | | | | | WALL R33 DBL | 34 | 647 | 0.0 |

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

| 1344 sq. ft | | | | 2200 sq. ft | | | | 2688 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** |
| WINDOW CL30 | 466 | 156 | 2.6 | WINDOW CL30 | 989 | 326 | 2.7 | WINDOW CL30 | 1006 | 336 | 2.7 |
| INFILTRATION @ 0.20 ACH w/HRV | 1610 | 672 | 2.1 | INFILTRATION @ 0.20 ACH w/HRV | 2751 | 1100 | 2.2 | INFILTRATION @ 0.20 ACH w/HRV | 3522 | 1344 | 2.3 |
| ATTIC R49 ADVrh | 823 | 520 | 1.4 | ATTIC R49 ADVrh | 1115 | 690 | 1.4 | ATTIC R49 ADVrh | 898 | 520 | 1.5 |
| WINDOW CL25 | 473 | 349 | 1.2 | WINDOW CL25 | 1019 | 730 | 1.2 | SLAB R10-FULL | 1567 | 1088 | 1.3 |
| WALL R21 INT+R5 | 1096 | 988 | 1.0 | WALL R21 INT+R5 | 2100 | 1840 | 1.0 | WINDOW CL25 | 1060 | 753 | 1.2 |
| FLOOR R38 STD w/12"Truss | 523 | 552 | 0.8 | FLOOR R38 STD w/12"Truss | 708 | 733 | 0.9 | BGWALL R21 | 170 | 146 | 1.0 |
| ATTIC R60 ADVrh | 220 | 520 | 0.4 | ATTIC R60 ADVrh | 297 | 690 | 0.4 | WALL R21 INT+R5 | 1223 | 1084 | 1.0 |
| WALL 8" SSPANEL | 356 | 1150 | 0.3 | WALL 8" SSPANEL | 641 | 2142 | 0.3 | ATTIC R60 ADVrh | 198 | 520 | 0.3 |
| WALL R33 DBL | 41 | 590 | 0.1 | WALL R33 DBL | 76 | 1099 | 0.1 | WALL 8" SSPANEL | 345 | 1262 | 0.2 |
| | | | | | | | | WALL R33 DBL | 43 | 647 | 0.1 |

## Table G-9: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 1

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** | **Measure** | **Savings (kWh/yr)** | **Installed Cost** | **Benefit/ Cost Ratio** |
| WINDOW CL35 | 676 | 135 | 4.5 | WINDOW CL35 | 1078 | 228 | 4.2 | WINDOW CL35 | 1579 | 343 | 4.1 |
| FLOOR R33 | 465 | 163 | 2.5 | FLOOR R33 | 806 | 276 | 2.6 | FLOOR R33 | 1213 | 415 | 2.6 |
| WINDOW CL30 | 230 | 103 | 2.0 | WINDOW CL30 | 406 | 175 | 2.1 | WINDOW CL30 | 619 | 263 | 2.1 |
| VAULT R30 | 95 | 47 | 1.8 | ATTIC R30 | 171 | 79 | 1.9 | ATTIC R30 | 261 | 118 | 2.0 |
| ATTIC R30 | 94 | 47 | 1.8 | VAULT R30 | 171 | 79 | 1.9 | VAULT R30 | 261 | 118 | 2.0 |
| DOOR R5 | 324 | 211 | 1.4 | DOOR R5 | 347 | 211 | 1.5 | DOOR R5 | 353 | 211 | 1.5 |
| WALL R21 ADV | 256 | 195 | 1.2 | WALL R21 ADV | 281 | 192 | 1.3 | WALL R21 ADV | 320 | 214 | 1.3 |
| ATTIC R38 | 66 | 70 | 0.8 | ATTIC R38 | 164 | 118 | 1.2 | ATTIC R38 | 252 | 178 | 1.3 |
| WINDOW CL25 | 159 | 231 | 0.6 | WINDOW CL25 | 394 | 392 | 0.9 | WINDOW CL25 | 604 | 588 | 0.9 |
| VAULT R38 | 40 | 70 | 0.5 | VAULT R38 | 98 | 118 | 0.7 | VAULT R38 | 152 | 178 | 0.8 |
| ATTIC R49 | 53 | 105 | 0.5 | ATTIC R49 | 126 | 178 | 0.6 | ATTIC R49 | 192 | 266 | 0.6 |
| FLOOR R44 | 53 | 163 | 0.3 | FLOOR R44 | 109 | 276 | 0.4 | FLOOR R44 | 186 | 415 | 0.4 |

## Table G-10:  Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 2

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio | Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio | Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio |
| WINDOW CL35 | 894 | 135 | 5.9 | WINDOW CL35 | 1367 | 228 | 5.3 | WINDOW CL35 | 1969 | 343 | 5.1 |
| FLOOR R33 | 614 | 163 | 3.3 | FLOOR R33 | 1065 | 276 | 3.4 | FLOOR R33 | 1593 | 415 | 3.4 |
| WINDOW CL30 | 304 | 103 | 2.6 | WINDOW CL30 | 532 | 175 | 2.7 | WINDOW CL30 | 811 | 263 | 2.7 |
| VAULT R30 | 127 | 47 | 2.4 | ATTIC R30 | 224 | 79 | 2.5 | ATTIC R30 | 342 | 118 | 2.6 |
| ATTIC R30 | 126 | 47 | 2.4 | VAULT R30 | 224 | 79 | 2.5 | VAULT R30 | 342 | 118 | 2.6 |
| DOOR R5 | 434 | 211 | 1.8 | DOOR R5 | 456 | 211 | 1.9 | DOOR R5 | 463 | 211 | 1.9 |
| WALL R21 ADV | 336 | 195 | 1.5 | WALL R21 ADV | 374 | 192 | 1.7 | WALL R21 ADV | 424 | 214 | 1.8 |
| ATTIC R38 | 93 | 70 | 1.2 | ATTIC R38 | 217 | 118 | 1.6 | ATTIC R38 | 333 | 178 | 1.7 |
| WINDOW CL25 | 222 | 231 | 0.8 | WINDOW CL25 | 524 | 392 | 1.2 | WINDOW CL25 | 798 | 588 | 1.2 |
| VAULT  R38 | 56 | 70 | 0.7 | VAULT  R38 | 129 | 118 | 1.0 | VAULT  R38 | 202 | 178 | 1.0 |
| ATTIC R49 | 74 | 105 | 0.6 | ATTIC R49 | 162 | 178 | 0.8 | ATTIC R49 | 246 | 266 | 0.8 |
| FLOOR R44 | 74 | 163 | 0.4 | FLOOR R44 | 145 | 276 | 0.5 | FLOOR R44 | 237 | 415 | 0.5 |

## Table G-11:  Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 3

| 924 sq. ft | | | | 1568 sq. ft | | | | 2352 sq. ft | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio | Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio | Measure | Savings (kWh/yr) | Installed Cost | Benefit/ Cost Ratio |
| WINDOW CL35 | 1073 | 135 | 7.1 | WINDOW CL35 | 1636 | 228 | 6.3 | WINDOW CL35 | 2362 | 343 | 6.1 |
| FLOOR R33 | 739 | 163 | 4.0 | FLOOR R33 | 1276 | 276 | 4.1 | FLOOR R33 | 1908 | 415 | 4.1 |
| WINDOW CL30 | 365 | 103 | 3.1 | WINDOW CL30 | 641 | 175 | 3.2 | WINDOW CL30 | 975 | 263 | 3.3 |
| VAULT R30 | 151 | 47 | 2.9 | ATTIC R30 | 270 | 79 | 3.0 | ATTIC R30 | 411 | 118 | 3.1 |
| ATTIC R30 | 151 | 47 | 2.9 | VAULT R30 | 270 | 79 | 3.0 | VAULT R30 | 411 | 118 | 3.1 |
| DOOR R5 | 523 | 211 | 2.2 | DOOR R5 | 549 | 211 | 2.3 | DOOR R5 | 556 | 211 | 2.3 |
| WALL R21 ADV | 407 | 195 | 1.9 | WALL R21 ADV | 448 | 192 | 2.1 | WALL R21 ADV | 508 | 214 | 2.1 |
| ATTIC R38 | 117 | 70 | 1.5 | ATTIC R38 | 263 | 118 | 2.0 | ATTIC R38 | 402 | 178 | 2.0 |
| WINDOW CL25 | 280 | 231 | 1.1 | WINDOW CL25 | 631 | 392 | 1.4 | WINDOW CL25 | 962 | 588 | 1.5 |
| VAULT  R38 | 70 | 70 | 0.9 | VAULT  R38 | 154 | 118 | 1.2 | VAULT  R38 | 241 | 178 | 1.2 |
| ATTIC R49 | 94 | 105 | 0.8 | ATTIC R49 | 195 | 178 | 1.0 | ATTIC R49 | 296 | 266 | 1.0 |
| FLOOR R44 | 94 | 163 | 0.5 | FLOOR R44 | 179 | 276 | 0.6 | FLOOR R44 | 286 | 415 | 0.6 |

Once the cost-effective level of the thermal shell was established the Council tested the cost-effectiveness of improving the efficiency of the homes space conditioning system. This was done by applying running the SEEM© model with higher performance heat pumps, improved duct systems, including moving all duct work and HVAC system inside the conditioned space, and carrying out heat pump commissioning and controls to ensure the system operated as designed. The average costs of these measures are shown in Table G-12. All of the measures listed in Table G-12 are regionally cost-effective, with total resource cost benefit-to-cost ratio greater than 1.0.

**Table G-12: Heating System Efficiency Improvements**

| HVAC System Efficiency Improvements | Incremental Cost (2006$) |
|---|---|
| PTCS Heat Pump Commissioning | $225 |
| PTCS - Duct Sealing | $300 |
| PTCS-Interior Ducts & HVAC | $350 |
| Air Source Heat Pump - Baseline (HSPF 7.7/SEER 13) | $3,880 |
| Air Source Heat Pump - (HSPF 8.5/SEER 14) | $5,790 |
| Air Source Heat Pump - Baseline (HSPF 9.0/SEER 14) | $6,900 |

In addition to space conditioning system efficiency improvements, recent changes to state energy codes have included lighting efficiency improvements. National model codes also include minimum lighting efficiency requirements. Therefore, the Council also analyzed lighting efficiency improvements. Four levels of efficiency, including baseline lighting power densities were reviewed for cost-effectiveness. It was assumed that all of these levels could be achieved with higher efficacy lighting technologies (compact fluorescent, LEDs) without reducing lumen levels. The estimated cost of these improvements is shown in Table G-13.

Reduction in lighting power densities interact with the space heating and cooling needs of a home. Therefore, to properly estimate the net savings from these lighting reductions the SEEM© model was run to calculate the space heating and cooling loads after their implementation. All of the lighting levels shown in Table G-13 are regionally cost-effective, with total resource cost benefit-to-cost ratios greater than 1.0.

**Table G-13: Lighting System Efficiency Improvements and Cost**

| Efficiency Level | Lighting Power Density (Watts/sq.ft.) | Cost/sq.ft. |
|---|---|---|
| Baseline | 1.75 | |
| Energy Star | 1.00 | $0.11 |
| Advanced | 0.75 | $0.17 |
| Full | 0.60 | $0.23 |

The 5$^{th}$ Plan's Model Conservation Standards did not cover water heating. Higher efficiency tanks have been available for decades and with the anticipated availability of heat pump water heaters, there is now a potentially cost-effective technology to reduce water heating consumption by as much as half. The estimated average cost and savings assumed for improving water heating efficiency are shown in Table G-14. Using these costs and savings, all of the water heating measures shown in Table G-14 are regionally cost-effective, with total resource cost benefit-to-cost ratios greater than 1.0.

**Table G-14: Water Heating System Efficiency Improvements and Cost**

| Water Heating System Type | DHW System Cost (2006$) | DHW Use (kWh/yr) |
|---|---|---|
| EF 0.90 | $649 | 3,655 |
| EF 0.92 | $669 | 3,576 |
| EF 0.94 | $746 | 3,500 |
| EF 2.2 | $1,450 | 1,499 |

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 conditioning, water heating and lighting 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-15 shows the maximum annual energy budget for space conditioning, water heating and lighting use permitted under the draft sixth 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 G-6 through G-14 that have a benefit-to-cost ratio of 1.0 or higher on a total resource cost basis.

**Table G-15: Draft Sixth Plan Model Conservation Standards Annual Space Conditioning, Water Heating and Lighting Budgets**[5]

| | Site Built Homes (kWh/sq.ft./yr) | Manufactured Homes (kWh/sq.ft/yr) |
|---|---|---|
| **Heating Zone 1** | 2.87 | 2.54 |
| **Heating Zone 2** | 4.27 | 3.54 |
| **Heating Zone 3** | 5.15 | 4.10 |

The Council compared the requirements underlying the performance shown in Table G-15 for site built homes with the requirements of state energy codes in the region. It also compared the requirements underlying the performance shown in Table G-15 with the requirements of regional Energy Star® site built and manufactured home program specifications. This comparison revealed that neither the region's energy codes, nor the Energy Star® program specifications, 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.

# 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-15 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

[5] Annual space conditioning, water heating and lighting use for a typical 2,250 sq.ft. site built home and 1,750 sq.ft. manufactured home. Both homes are assumed to have air source heat pumps with a minimum HSPF 9.0/SEER 14, heat pump water heater and maximum lighting power density of 0.6 Watts/sq.ft.

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 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 1,500 different combinations of major variables that determine a specific consumer's life cycle cost of home ownership for each heating climate zone. Table G-16 lists these variables and the data sources used to derive the actual distribution of values used.

**Table G-16: 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 |
| **Downpayment** | Federal Housing Finance Board |
| **Private Mortgage Insurance Rates** | Mortgage Bankers Association |
| **Retail Electric Rates** | Energy Information Administration |
| **Retail Gas Rates** | Energy Information Administration |
| **Retail Electric and Gas Price Escalation Rates** | Council Draft 6th Plan 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 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 used 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 G-1 through G-6 show the distributions used for each of the major financial input assumptions to the life cycle cost analysis.

**Figure G-1: Distribution of Nominal Mortgage Rates**

**Figure G-2: Distribution of Downpayment Amounts**

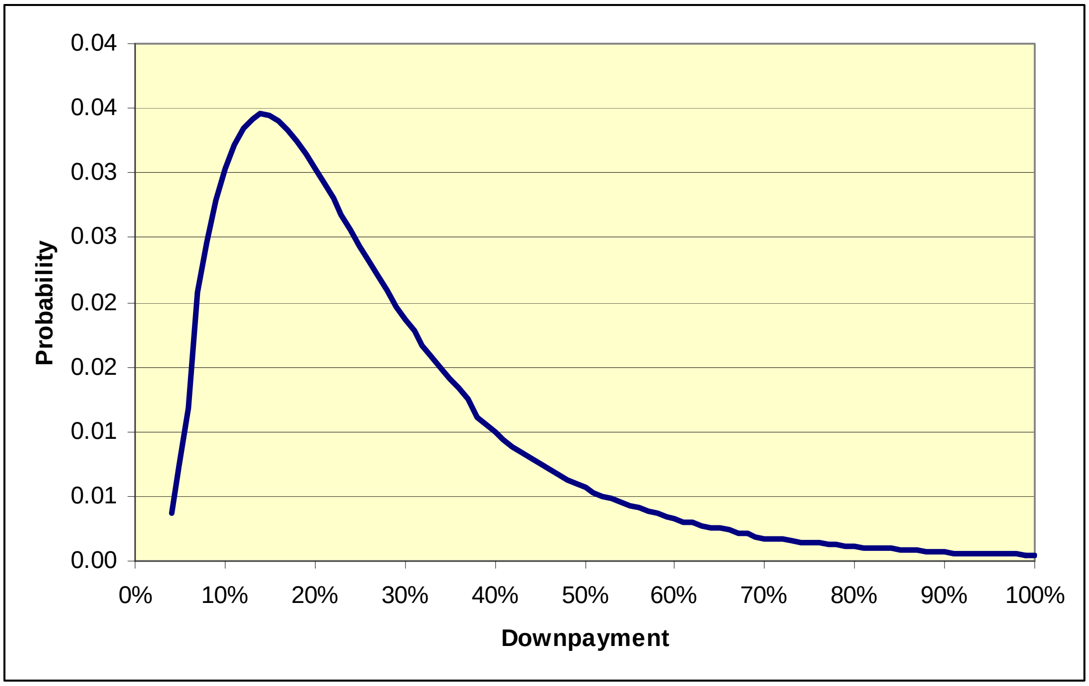



**Table G-17: Distribution of Marginal State and Federal Income Tax Rates**

| | Idaho | | | Montana | | | Oregon | | | Washington | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Adjusted Gross Income | Federal Tax Rate | State Income Tax Rate | Share of Returns | Federal Tax Rate | State Income Tax Rate | Share of Returns | Federal Tax Rate | State Income Tax Rate | Share of Returns | Federal Tax Rate | State Income Tax Rate | Share of Returns |
| Under $10,000 | 10% | 5.1% | 20.0% | 10% | 3.0% | 24.4% | 10% | 7.0% | 18.6% | 10% | 0.0% | 16.8% |
| $10,000 Under $20,000 | 15% | 7.1% | 19.3% | 15% | 5.0% | 20.8% | 15% | 9.0% | 18.1% | 15% | 0.0% | 16.1% |
| $20,000 Under $30,000 | 15% | 7.8% | 15.0% | 15% | 6.0% | 14.2% | 15% | 9.0% | 14.4% | 15% | 0.0% | 13.7% |
| $30,000 Under $50,000 | 18% | 7.8% | 19.6% | 18% | 8.0% | 18.0% | 19% | 9.0% | 19.5% | 20% | 0.0% | 19.8% |
| $50,000 Under $75,000 | 25% | 7.8% | 13.6% | 25% | 9.0% | 12.1% | 25% | 9.0% | 14.1% | 25% | 0.0% | 15.5% |
| $75,000 Under $100,000 | 25% | 7.8% | 5.7% | 25% | 10.0% | 4.6% | 25% | 9.0% | 6.8% | 25% | 0.0% | 8.1% |
| $100,000 Under $150,000 | 28% | 7.8% | 3.2% | 28% | 11.0% | 2.4% | 28% | 9.0% | 4.3% | 28% | 0.0% | 5.5% |
| $150,000 Under $200,000 | 28% | 7.8% | 0.9% | 29% | 11.0% | 0.8% | 29% | 9.0% | 1.3% | 29% | 0.0% | 1.5% |
| $200,000 Under $500,000 | 33% | 7.8% | 0.9% | 33% | 11.0% | 0.8% | 33% | 9.0% | 1.3% | 33% | 0.0% | 1.5% |
| $500,000 Under $1,000,000 | 35% | 7.8% | 0.2% | 35% | 11.0% | 0.1% | 35% | 9.0% | 0.2% | 35% | 0.0% | 0.3% |
| $1,000,000 and Over | 35% | 7.8% | 0.1% | 35% | 11.0% | 0.0% | 35% | 9.0% | 0.1% | 35% | 0.0% | 0.2% |

**Figure G-3: Property Tax Rates by State**

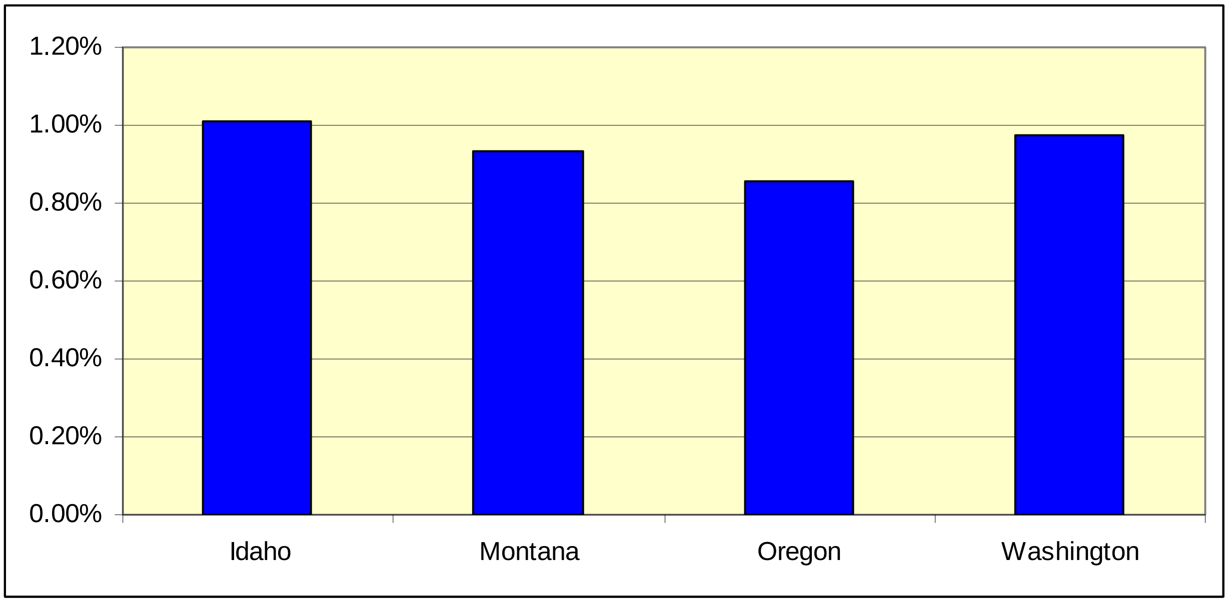



**Figure G-4: Base Year Retail Electric Rates by Climate Zone**

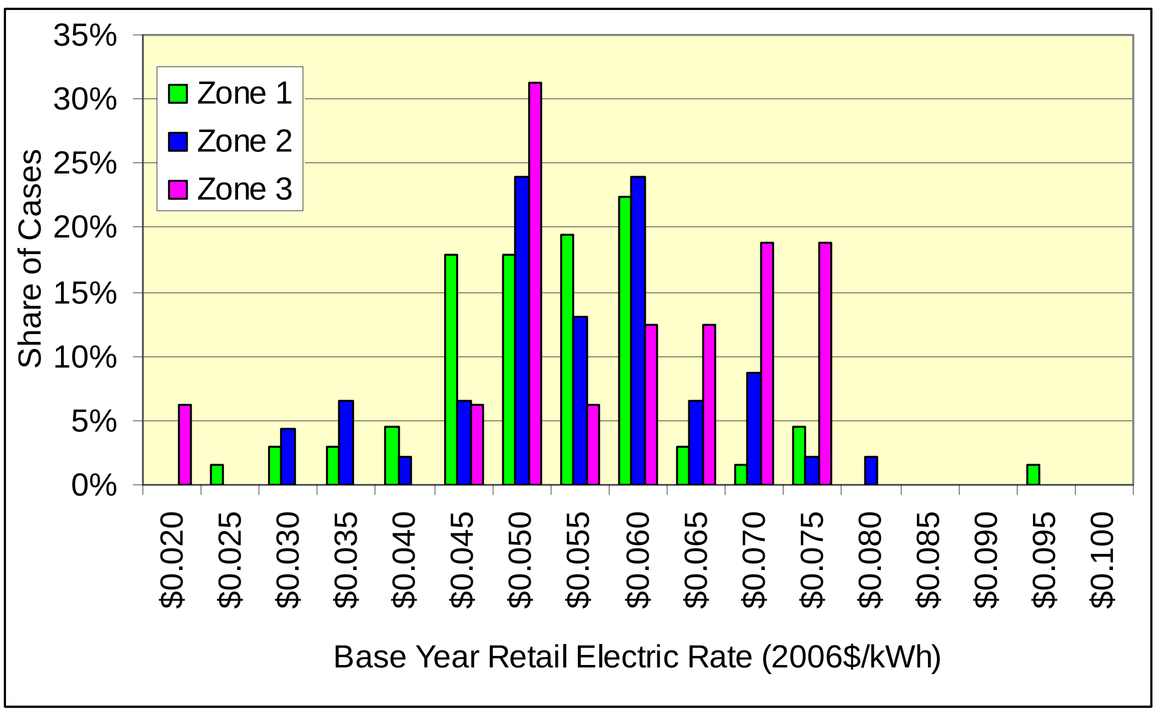
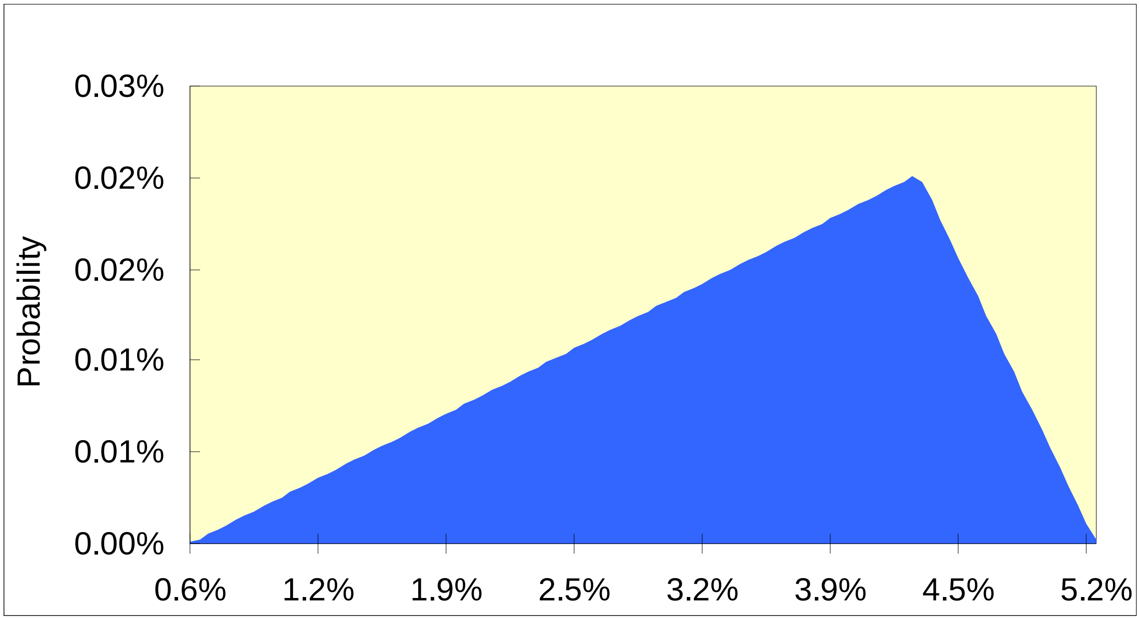


**Figure G-5:  Nominal Escalation Rates for Retail Electricity Prices - All Climate Zones**




The incremental costs of conservation measures described in the prior section on regional cost-effectiveness were used in the life cycle cost calculations.  Annual space heating and cooling energy use was computed for four heating system types using the system efficiency assumptions shown in Table G-12 and the water heating and lighting use shown in Tables G-13 and G-14.

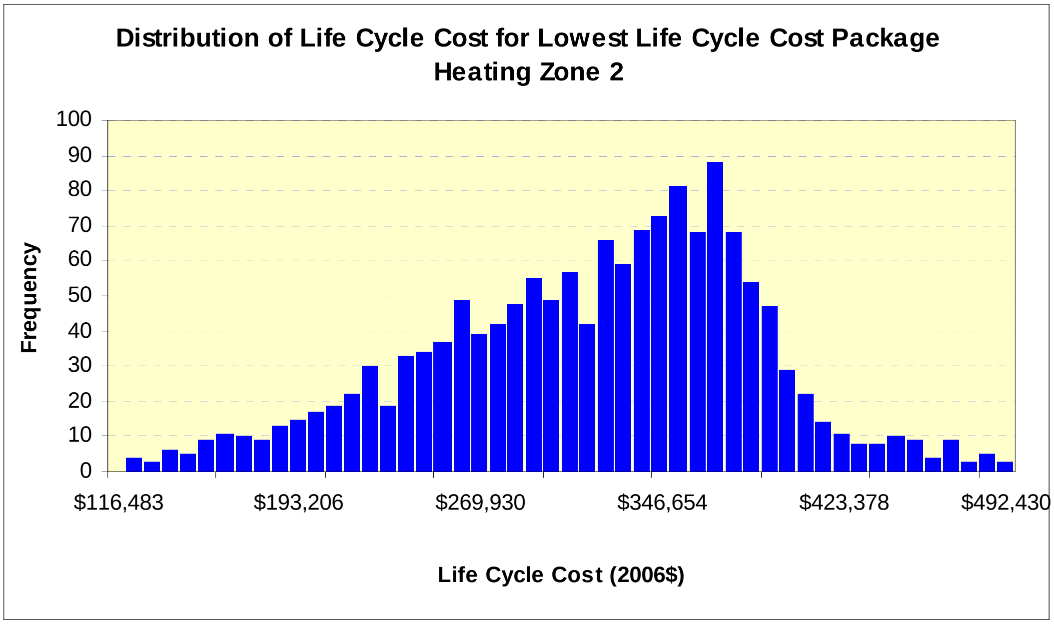
The life cycle cost simulation model used the same 1,500 combinations of input assumptions for each level of energy efficiency tested.  As a result, the Council could compare the distribution of 1,500 different life cycle cost results for a home built to incrementally higher levels of efficiency, rather 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-6 illustrates a typical distribution of net present value results for one of the lowest life cycle cost package identified for Heating Zone 2.  The graph plots the life cycle cost value of a conservation package (i.e., thermal shell, space conditioning system, water heating system and lighting system) costs and energy use over the term of the mortgage on the horizontal (x) axis. The frequency of obtaining a given life cycle cost is plotted on the vertical (y) axis.

The simulation model was set up to seek out the lowest life cycle cost path to comply with current codes. In this case, the model was only permitted to select different electric space conditioning systems.  That is, it was not allowed to choose improvements in thermal shell, water heating, lighting or duct system efficiency. Table G-18 shows the mean life cycle cost, first cost and energy use of for each of the regions three heating zones for new single-family homes and for new manufactured homes.

Once the “base case” homes life cycle cost was established the model was set up to seek out the lowest life cycle cost package of measures by selecting various combinations of thermal shell improvements, space conditioning systems, duct system efficiencies and lighting and water heating system efficiency improvements. Table G-19 shows the mean life cycle cost, first cost and annual energy use for the package that performed best across all 1,500 different combinations of financial inputs.

**Figure G-6: Illustrative Distribution of Life Cycle Cost Results**




Finally, the simulation model was run to determine the life cycle cost of the package for each heating zone that includes all measures that were found to regionally cost-effective to the power system. Table G-20 shows the mean life cycle cost, first cost and annual energy use for these packages for each climate zone.

A comparison of the energy use for the lowest life cycle cost packages shown in Table G-19 with the life cycle cost of the packages containing all regionally cost-effective measures shown in Table G-20 reveals that across all climate zones and building types, life cycle costs are higher for those packages containing all regionally cost-effective measures.

**Table G-18: Lowest Life Cycle Minimally Code Compliant Packages (Base Case)**

| | Life Cycle Cost - 30 yrs | | First Cost | | Total Use (kWh/yr) | |
|---|---|---|---|---|---|---|
| | Single Family | Manufactured Home | Single Family | Manufactured Home | Single Family | Manufactured Home |
| Zone 1 | $314,247 | $99,749 | $2,297 | $8,732 | 17,575 | 10,131 |
| Zone 2 | $324,608 | $104,167 | $2,297 | $8,732 | 19,551 | 14,528 |
| Zone 3 | $255,368 | $103,076 | $2,297 | $8,732 | 26,752 | 17,158 |

**Table G-19: Lowest Life Cost Cycle Packages (Economically Feasible)**

| | Life Cycle Cost - 30 yrs | | First Cost | | Total Use (kWh/yr) | |
|---|---|---|---|---|---|---|
| | Single Family | Manufactured Home | Single Family | Manufactured Home | Single Family | Manufactured Home |
| Zone 1 | $307,500 | $93,705 | $10,899 | $10,908 | 9,265 | 5,431 |
| Zone 2 | $315,460 | $95,623 | $10,899 | $10,904 | 10,462 | 7,165 |
| Zone 3 | $242,302 | $91,231 | $10,899 | $11,107 | 12,453 | 8,173 |

**Table G-20:  All Regionally Cost-Effective Packages (MCS)**

| | Life Cycle Cost - 30 yrs | | First Cost | | Total Use (kWh/yr) | |
|---|---|---|---|---|---|---|
| | Single Family | Manufactured Home | Single Family | Manufactured Home | Single Family | Manufactured Home |
| Zone 1 | $308,254 | $94,593 | $12,068 | $11,617 | 6,449 | 4,334 |
| Zone 2 | $316,107 | $96,303 | $12,068 | $11,617 | 9,776 | 6,204 |
| Zone 3 | $242,780 | $91,658 | $12,068 | $11,617 | 11,714 | 7,170 |

Table G-21 shows differences in the buildings shell between the lowest life cycle cost packages and the packages that contain all regionally cost-effective measures.  A review of Table G-21 reveals that the only difference in the thermal shell is in the level of attic insulation and air sealing.

**Table G-21:  Comparison of Thermal Shell Measures in Lowest Life Cycle Cost Packages and All Regionally Cost-Effective Packages**

| Component | Regionally Cost-Effective (All Zones) | Minimum Life Cycle Cost (All Zones) |
|---|---|---|
| **Wall – Above Grade** | R21 Advanced Framing | R21 Advanced Framing |
| **Wall – Below Grade** | R19 | R19 |
| **Attic** | R49 Advanced | R38 STD |
| **Vault** | R30 | R30 |
| **Floor** | R30 | R30 |
| **Window** | Class 25 | Class 25 |
| **Door** | R5 | R5 |
| **Slab** | R10 Full Under Slab | R10 Full Under Slab |
| **Wall – Ext. Below grade** | R10 | R10 |
| **Infiltration** | Air Sealing w/HRV | Current Practice |

Table G-22 shows the differences in the space conditioning, water heating and lighting system efficiency components between the lowest life cycle cost packages and the packages containing all regionally cost-effective measures.  As can be seen in Table G-22 the only difference between the lowest life cycle cost package and the package containing all regionally cost-effective measures is the minimum efficiency requirements for the heat pump space conditioning system.

**Table G-22:  Comparison of Space Conditioning, Water Heating and Lighting Measures in Lowest Life Cycle Cost Packages and All Regionally Cost-Effective Packages**

| Component | Regionally Cost-Effective | Minimum Life Cycle Cost |
|---|---|---|
| **HVAC System** | HSPF 9.0/SEER 14 Heat Pump | HSPF 7.7/SEER 13 Heat Pump |
| **Duct System** | Interior Ducts | Interior Ducts |
| **Water Heater** | Heat Pump | Heat Pump |

| | | |
|---|---|---|
| **Lighting** | 0.6 Watts/sq.ft. | 0.6 Watts/sq.ft. |

# Appendix H: Demand Response

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## INTRODUCTION

The Council's definition of demand response (DR) is voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in use is usually a reduction, but there could be situations in which an increase in use would relieve stress on the power system and would qualify as DR.

Demand response is similar to conservation in that it occurs on the consumer's side of the meter. However, while conservation is an increase in efficiency that reduces energy use while leaving consumers' levels of service unchanged, demand response is a change in use of electricity at particular times that may change quality or level of service and may in some cases actually increase energy use overall.

This appendix reviews the treatment of demand response in the Council's Fifth Power Plan, reviews progress in understanding and implementation of demand response since that plan, and describes the work on demand response in the Sixth Power Plan.

# DEMAND RESPONSE IN THE COUNCIL'S FIFTH POWER PLAN

The Council's Fifth Power Plan[1] was the first of the Council's plans to consider demand response as a resource.[2] The plan explained that concern with demand response rises from a disconnect between power system costs and consumers' prices. While costs of providing electricity vary with power system circumstances that change from hour to hour and season to season, electricity consumers seldom see prices that reflect these "real time" costs. This disconnect leads to higher consumption at high cost times than is optimal, with overinvestment in peaking capacity.

The Fifth Power Plan examined two general categories of options to remedy the disconnect, pricing and programs.

## *Pricing Options*

The Fifth Power Plan outlined the main categories of retail pricing options that have been proposed for incenting demand response. The objective of these options is to give consumers prices that more closely approximate actual system costs through the hours of the year, leading consumers to reduce their usage appropriately when system costs are high. The plan described three main categories of time sensitive pricing structures and their advantages and disadvantages:

***Real time prices*** vary with demand and supply conditions as they develop, so that consumers receive efficient signals to guide their usage decisions. Since real time prices will often vary from one hour to the next, they require meters that record hourly use and that can notify customers of the hourly changes in prices. These meters were less common when the fifth plan was being developed than they are now, but they are still an obstacle to universal use of real time prices. Real time prices can convey the most accurate reflection of electricity costs as events occur, but they can also be the most volatile of pricing structure, and that volatility has been a concern for many customers and regulators.

***Time of use prices*** are set based on expected costs of serving loads in specified seasons and times of day. Time of use prices are set for a year or more at a time, so are less volatile than real time prices, but they are inherently less able to reflect the unexpected demand and supply situations that occur and that represent the greatest opportunities for demand response to benefit the power system. In short, time of use rates raise less concerns among regulators and ratepayers, but they have less potential benefits.

***Critical peak prices*** can be viewed as a compromise between real time prices and time of use prices. Critical peak prices are usually set at mutiples (4-6 times) of ordinary retail rates, but only apply to a small part of the year, typically 1 percent of all hours (87 hours/year), limiting volatility in customers' bills. At the same time, critical peak prices have some of the efficiency

[1] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf.

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

potential of real time prices, because utilities can call critical peak price events when the system is most in need of demand response (with previous notice, commonly 24 hours).

## *Program Options*

The Fifth Power Plan described the main categories of program alternatives to pricing policies to achieve demand response. These program alternatives all involve some form of compensation to customers willing to modify their use, or allow the utility to modify their use, of power when it benefits the power system:

***Interruptible contracts*** have been used for many years to help utilities manage the risk of unexpected problems. For a discount in the customer's underlying price, the utility has the right to cut service to the customer when necessary. The discount and terms of interruption vary.

***Direct control*** has also been used for many years, typically applied to air conditioners. The customer is typically compensated with a seasonal discount in exchange for the utility's right to reduce air conditioning service for a specified number of times during the season.

***Demand buyback*** has been used in the Pacific Northwest and elsewhere to enable customers who were unwilling to make the commitment called for by interruptible contracts or direct control programs to play a part in demand response. Customers participating in demand buyback programs respond on a day-ahead basis to offers from the utility or system operator of payment for load reduction. Typically the utility announces what it is willing to pay for load reduction the next day and the customer responds with an amount of reduction it is willing to make for that level of compensation. The utility notifies customers whose reductions will be compensated usually the afternoon of the day before reductions are needed.

***Emergency generation*** installed in such facilities as hospitals, data centers and office buildings can be dispatched by the local utility, subject to environmental limitations. Arrangements between the utility and the owners of emergency generation can be anything acceptable to both parties, but may include a reservation or capacity payment and an energy payment when the generator is operated.

## *Estimate of Potential Demand Response*

The Fifth Power Plan reviewed DR experience in the Pacific Northwest and elsewhere in the U.S. While the Pacific Northwest pursued some kinds of demand response during the 2000-01 West Coast electricity market crisis, historically the hydroelectric system of our region had made it relatively easy to meet our regional peak demands without demand response. By contrast, elsewhere in the U.S. the costs of meeting peak loads were closely related to building more thermal generation, at higher costs, creating incentives to consider demand side alternatives, i.e. demand response. As a result, demand response experience was generally more common outside the Pacific Northwest.

The Fifth Power Plan made a very simple estimation of the possible size of the demand response, arriving at about 1,600 megawatts[3] by a set of conservative assumptions, and the plan used 2,000

[3] Page H-13, Appendix H of the Fifth Power Plan

megawatts as the basis for its portfolio analysis of the effect of demand response on long run cost and risk. These estimates matched rules of thumb and experience from around the country, which suggested that demand response potential in the range of 5 percent of peak load[4] was a reasonable target.

## Estimates of Cost Effectiveness of Demand Response

The plan's exploration of cost effectiveness measures of demand response examined three methods of estimating the generating cost avoided by demand response:

***A simplistic estimate of the cost/MWh at an assumed number of hours of operation of a "stand-alone" peaking generator.*** This method resulted in estimates of $677/MWh to $1,179/MWh for generators running 100 hours/year, with higher costs for generators running fewer hours/year.[5]

***The estimation of the incremental cost of electricity from peaking generators added to the existing system, with credit of operational savings and spot market sales from the new units.*** This estimation used the AURORA® model to simulate the operation of the interconnected power system of the entire Western U.S. along with the Canadian provinces of British Columbial and Alberta and the norther part of Baja California in Mexico. The resulting estimates of avoided cost ranged from $519/MWh to over $14,000/MWh, depending on hydro conditions and reserve margin assumptions.[6]

***The simulation of the effect of demand response on the cost and risk of the power system over a range of 750 possible 20-year futures, using the Council's portfolio model.*** This simulation did not estimate avoided cost, but compared the cost and risk combinations of portfolios that included up to 2,000 megawatts of demand response with fixed costs of $2,260/MW-yr and variable costs of $150/MWh,[7] compared to portfolios with no demand response. The comparison showed substantial net reductions in both cost and risk when demand response was included in the portflios. These net benefits clearly indicate that demand response at these costs is cost effective.

The results of the different methods differed, but they all indicated that reductions in demand for electricity at appropriate times could avoid very significant costs, and in the case of the portfolio model method could reduce the financial risks to the system as well.

## Action Plan

The Fifth Power Plan set a target of 500 megawatts of demand response to be achieved by 2009. This target was not based on detailed analysis of acquisition costs of demand response, since our experience with these costs was slim. Instead, the target was intended to encourage utilities and others in the region to gain experience with demand response, putting future programs and analysis on a firmer basis.

[4] The system peak load has ranged up to 36,000 megawatts in the period 1992-2007, five percent of this would be 1,800 megawatts.
[5] Page H-16, Appendix H of the Fifth Power Plan
[6] Table H-2, Appendix H of the Fifth Power Plan
[7] Page H-21, Appendix H of the Fifth Power Plan

Finally, the Fifth Power Plan also included eight action items for the region to accomplish by 2009:

1. Expand and refine existing programs.

2. Develop cost effectiveness methodology for demand response.

3. Incorporate demand response in utilities' integrated resource plans.

4. Evaluate the cost and benefits of improved metering and communication technologies.

5. Monitor cost and availability of emerging demand response technologies.

6. Explore ways to make price mechanisms more acceptable.

7. Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation.

8. The Council will host several workshops to identify and coordinate efforts to accomplish these action items.

# PROGRESS SINCE THE FIFTH PLAN

## *Action Plan Items*

Since the release of the Council's Fifth Power Plan there have been a number of developments related to demand response. Several of these developments are related to the action items just listed:

**Action Item 1.** A number of existing demand response programs have been expanded. Idaho Power and PacifiCorp have expanded programs that allow them to interrupt air conditioning and irrigation. Portland General Electric has substantially increased the number of their customers' standby generators that PGE can dispatch when necessary.

**Action Items 2, 6, and 8.** Council staff held 3 workshops in 2005 and 2006. These workshops focused mainly on cost effectiveness methodology. Beginning in 2007 the Council, along with the Regulatory Assistance Project (RAP) and Lawrence Berkeley National Laboratory (LBNL),[8] formed the Pacific Northwest Demand Response Project (PNDRP).

The objective of the PNDRP is to provide suggestions to the region's regulators to help encourage the development of demand response. Consultation with the regulators resulted in narrowly focusing the topics to be taken up by the PNDRP: cost effectiveness methodology, pricing strategies, and the integration of demand response into transmission and distribution planning. By December of 2008 PNDRP had succeeded in agreeing on a set of cost effectiveness guidelines, and began to examine pricing strategies. These cost effectiveness guidelines provide an initial valuation framework for demand response resources and should be

[8] The participation of the RAP and LBNL is supported by the U.S. Department of Energy.

considered as a screening tool by state commissions and utilities in the Pacific Northwest. The cost effectiveness guidelines are at the end of this Appendix in Appendix H-1.

The PNDRP is expected to continue work on pricing strategies in the spring of 2010.

Council staff is also working on incorporating risk into the evaluation of cost effectiveness of demand response, using the Council's portfolio model. Progress in this work is described below, in the "Portfolio Analysis of Demand Response since the Fifth Plan" section.

**Action Item 3.** Utilities are including demand response in their integrated resource plans, and further expansions of demand response programs are planned.

**Action Item 4.** Portland General Electric and Idaho Power have begun to install advanced metering for all their customers. In addition, with funding from the American Recovery and Reinvestment Act (ARRA) the U.S. Department of Energy has awarded grants to Avista Utilities, Central Lincoln People's Utility District, Idaho Power Company, Pacific Northwest Generating Cooperative, and Snohomish Public Utility District to support the purchase and installation of smart grid technologies, which will include improved metering and communication. U.S. DOE has also awarded a grant to the Western Electricity Coordinating Council (WECC) for similar purposes, which will involve the participation of three regional utilities, Bonneville Power Administration, Idaho Power Company, and PacifiCorp. These grants require negotiations between the recipients and U.S. DOE to finalize details, so that the final list of projects that will proceed was not known when this was written.

Bonneville, Battelle and 12 partners also have submitted a proposal to U.S. DOE to demonstrate the practicality and value of smart grid technologies. This project had not been approved when this was written, but the proposers hope to hear about funding before the end of 2009.

**Action Item 5.** Council staff and others in the region have continued to monitor potential new demand response technologies. Perhaps the most significant development in this area is the growth of demand response aggregators. These aggregators are not really new technology, rather a combination of existing communication and control technology, together with a business model that calls makes the aggregator the intermediary between the utility and the customer when demand response is needed. The aggregator enlists customers, installs controls on selected equipment on the customers' premises, and guarantees reductions to utilities or system operators when needed. Utilities, both in our region and elsewhere, can "pay for performance" without developing all the program capability themselves, which is attractive to many utilities.

**Action Item 7.** In the last year or so the combination of increasing demand for electricity together with the necessity to accommodate increasing amounts of wind generation has focused attention on ancillary services, in particular regulation and load following.[9] Bonneville's balancing authority has been the one most affected by wind development in the region, and Bonneville has done significant analysis on the cost of incremental ancillary services. Bonneville also distributed a Request for Information (RFI) in August of 2008, asking for information on generation or loads that could provide regulation or load following to help integrate wind generation.

[9] More complete discussion of regulation and load following is in Chapter 11.

Achievement of 500 megawatts of demand response by 2009: The achievement of the 500 megawatt target for demand response developed by 2009 depends on how the megawatts are counted. Regional utilities have at least 700 megawatts of demand response acquired or planned by the end of 2009. Significant parts of this demand response are outside our region in the eastern part of PacifiCorp's service territory, though this demand response benefits the western part of PacifiCorp's system (in our region) as well. While we cannot precisely allocate the share of total demand response that is in our region, it is less than the 500 megawatts target.

Some of the details of these accomplishments are proprietary, but the major components are: reductions in air conditioning and irrigation by Idaho Power and PacifiCorp, curtailable industrial loads, dispatchable standby generation by Portland General Electric,[10] and day-ahead demand buyback programs by PacifiCorp and Portland General Electric.

While our region as a whole is winter peaking, much of the 2005-2009 experience with demand response affects summer loads. However, even though summer demand response may not reduce the region's absolute peak loads it could have as much or more value than winter demand response. Analysis by the Adequacy Forum[11] suggests that summer peaking capacity may become short before winter peaking capacity. Further, regional spot prices for electricity, heavily influenced by summer peaking loads in California and the Southwest, already tend to be higher in the summer than in the winter. As a result, the experience with summer demand response programs has significant value for the region.

There have also been developments that were not anticipated by the Fifth Power Plan's action items. Several utilities have contracted estimates of supply curves for demand response.[12] This work, based on our current level of experience, cannot foresee all the demand response measures we will eventually discover, or foresee all the means of obtaining demand response we will eventually devise, but the estimates are steps forward in our understanding of demand response.

## *Portfolio Analysis of Demand Response since the Fifth Plan*

Compared to no demand response, including demand response in the Fifth Plan reduced both cost and risk all along the "efficient frontier" of possible portfolios. Since the release of the Fifth Power Plan Council staff have conducted additional portfolio analysis of the effects of demand response. Much of this analysis explored the cost effectiveness of demand response. The work estimated combinations of fixed and variable costs that that result in power system costs and risks that are equivalent to no demand response at all.[13] At these combinations of costs, the costs of the demand response program just balance the reductions in other resource costs. These combinations of costs can be characterized as the "cost effectiveness frontier" and can be illustrated by Figure H-1.

[10] Other utilities have called on customers' standby generation on an ad hoc basis in special circumstances.
[11] See the 2008 Assessment at http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc
[12] Including Bonneville, PacifiCorp, Puget Sound Energy and Portland General Electric
[13] See Appendix H-3 for a detailed description of the work and findings.

**Figure H-1: Cost Effectiveness Frontier of Demand Response**

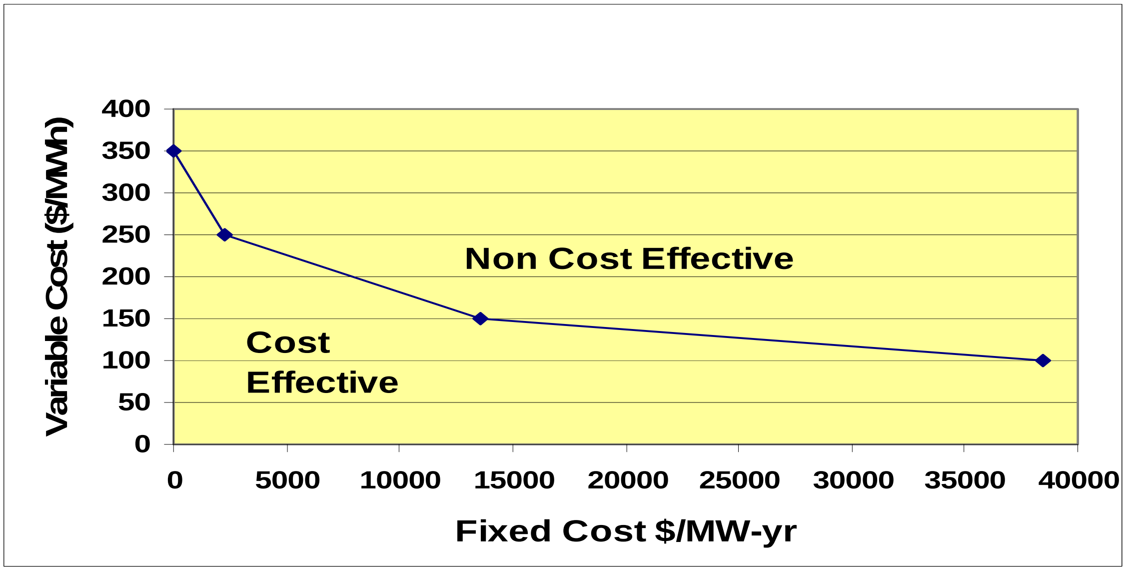


Figure H-1 shows combinations of fixed costs, graphed on the horizontal axis, and variable costs, graphed on the vertical axis. The cost effectiveness frontier divides all possible combinations of fixed and variable costs into two sets, combinations above the frontier and combinations below it. Combinations whose costs graph below the frontier are cost effective; that is, demand response with these costs reduces system costs and risks.

The cost effectiveness frontier offers some advantages to regulators and utility program designers, compared to alternative indicators of cost effectiveness. Since it is based on the Council's portfolio analysis, the effects of demand response not only on cost but also on risk are incorporated. The frontier takes into account the tradeoff between fixed costs and variable costs of demand response, and provides a rough measure of effectiveness that helps identify programs that are worthy of more detailed analysis.

But this cost effectiveness frontier has shortcomings. It represents a single, simplified "generic" demand response program that is available in all seasons at the same cost and capacity, and it is modeled in the portfolio as a resource to help the power system meet peak demand. As has been discussed earlier, we're coming to appreciate that demand response may be able to provide a range of services to the power system, from peak load service, to contingency reserves, to reguation and load following. Some loads may be able to provide more than one of these services. To reflect this world, several demand response programs will need to be simulated in the portfolio model. In addition, the portfolio model currently cannot simulate ancillary services, so the cost effectiveness frontier cannot reflect reflect benefits from ancillary services provided by demand response.

For the time being, the cost-effectiveness frontier approach to identifying cost effective demand response is a work in progress, and is not proposed as a proven and mature measure for decision making.

# DEMAND RESPONSE IN THE SIXTH PLAN

## *Estimation of Available Demand Response*

The Fifth Power Plan used estimated short-term price elasticities to arrive at a very rough estimate of the potential size of the demand response resource.[14] The estimate was presented not as being accurate within 10 or 20 percent, but as supporting the potential significance of a resource that we were just beginning to understand. While there is now more experience with demand response, there is still a great deal to learn about how much demand response is possible and how best to achieve it.

The concept of a supply curve for demand response is very attractive -- the region has worked (and still works) on supply curves for conservation, arranging conservation measures and programs in order of increasing costs, to help identify which measures are most attractive and to help identify where to draw the line for cost effectiveness. We'd like similar help with demand response, but some qualities of demand response make the estimation of supply curves for it more complicated:

1. The amount of available demand response varies with season, time of day, and power system conditions. For example, on an August afternoon customers can accept higher temperatures to reduce air-conditioning load, but that response is not available when there is little or no air-conditioning load, such as the cool night hours in most months.

2. Demand response can provide a variety of services to the power system (e.g. peak load service, contingency reserves, regulation, load following) as described later in this Appendix. Each of these services will have its own supply, which will vary over time. To estimate a supply curve for demand response to help meet peak loads we must consider whether some of the same customers and actions will be providing contingency reserves or load following services as well -- otherwise we run the risk of counting the same actions twice in separate supply curves.

3. The costs of demand response are more complex than those of conservation. The costs of conservation are generally fixed, as are the amount and schedule of energy savings. In contrast, demand response often comes with fixed and variable cost components, and requires a "dispatch" decision (by the utility or the customer) to reduce energy use at a particular time. The variable cost of demand response is the major factor in that decision.

4. Displaying demand response in the normal cost vs. quantity format of a supply curve requires some sort of aggregation of the fixed and variable costs into a single measure, such as the "average cost per megawatt of a demand response program that operates 100 hours per year." But a supply curve displaying such aggregated costs may distort critical information about a demand response program. In this example, depending on the variable cost of the program, it may or may not make sense to operate it the assumed 100 hours per year.

[14] Page A-8, Chapter 4 of the Fifth Power Plan

5. Estimates of conservation potential have depended on understanding the performance of "hardware" such as insulation and machinery, predictable by engineering analysis. Estimates of demand response, on the other hand, depend more on understanding the behavior of consumers exchanging comfort or convenience for compensation. This behavior is not so predictable without actual experience, which so far is quite limited.

6. The economics of demand response will be powerfully influenced by technological change, particularly the development of "Smart Grid" technologies,[15] which promise to make more and cheaper demand response available. Such technological change is impossible to predict in specifics, but it seems inevitable that there will be significant change over the next 20 years, and that the change will make demand response more attractive.

With the limited experience available now, a balance must be struck between the precision and the comprehensiveness of estimates of potential demand response. Precise estimates need to be limited to customers, end uses, and incentives where there is experience. These estimates necessarily exclude some possibilities that are virtually certain to have significant demand potential, eventually. Comprehensive estimates avoid this tendency to underestimate potential by including possibilities where there is less experience, but the estimates are therefore less precise.

Each of these approaches has its place. An estimate for a near-term implementation plan must focus on the "precise" end of this spectrum. An estimate for a long run planning strategy, such as the Council's, should focus on the "comprehensive" end. The long term goal should be to expand experience with various forms of demand response to the point that a precise estimate of available demand response is also comprehensive. It's fair to say this goal has been reached in the estimation of conservation potential, but has not yet been reached for demand response, at least for the region as a whole.

## Studies of Potential

With these caveats about the limitations of estimating potential demand response based on limited experience, the regional discussions and analysis since the Fifth Power Plan have advanced our understanding of the resource. In our region, Bonneville, PacifiCorp, Portland General Electric, and Puget Sound Energy have contracted studies of potential.

Global Energy Partners and The Brattle Group performed Bonneville's study. The study estimated demand response available through 2020 and included direct load control of residential and small commerical customers, an "Emergency Demand Response"[16] program for medium and large commercial and industrial customers, capacity market options,[17] customers' participation in a market for ancillary services, and two pricing options. The study estimated potential demand response for each of theses options. The estimates took each option alone, with no attempt to estimate the interactions among them -- as a result, adding the estimates together risks double counting some demand response.

[15] See Appendix K
[16] Customers are offered payment for load reductions during system events, but are not penalized if their usage does not change.
[17] Customers are paid to commit to reduce loads when required by the power system, and receive additional payment when they are actually called to reduce load.

Council staff extended this study's results for direct load control, emergency demand response, and capacity market options proportionally to the entire region by assuming that these programs did not double count potential so that they could be summed. The upper end of the range of regional estimates resulting from this extension amounted to about 1.4 percent of peak load in the winter and 2.2 percent of peak load in the summer in 2020.

Puget Sound Energy (PSE) commissioned a study by Cadmus in 2009 that is still being revised. Preliminary results indicate that about demand response equal to about 3 percent of 2029 forecast peak load will be available.

The studies of demand response potential for PacifiCorp and Portland General Electric had not been completed at the time the Council approved the Sixth Power Plan.

## Experience

In addition to estimates of demand response available in the future, there is considerable experience around the country with demand response that has been acquired or is in the last stages of acquisition by utilities and system operators. This experience gives some idea of the total amount of demand response that can be expected when utilities pursue it aggressively over a period of time.

In the Pacific Northwest, PacifiCorp has been quite active in acquiring demand response. By 2009, PacifiCorp expected to have over 500 megawatts of demand response, including direct load control of air conditioning and irrigation, dispatchable standby generation, and interruptible load. PacifiCorp also calls on demand buy back and "Power Forward."[18] These last two components are considered non-firm resources, but have combined to provide reductions in the 100 to 200 megawatts range in addition to the 500 megawatts of firm megawatts. The demand response, compared to PacifiCorp's forecasted peak load of 9,800 megawatts for 2009, means that PacifiCorp has more than 5 percent of peak load in firm demand response, and another 1-2 percent in non-firm demand response.

Idaho Power had about 60 megawatts of demand response in 2008, made up of direct load control of residential air conditioning and timers on irrigation pumps. The company is committeed to expand their demand response to 293 megawatts by 2013 by converting much of their irrigation demand response to dispatchable[19] and adding demand response from the commercial and industrial sectors. This level would be 7.7 percent of their projected peak demand in 2013 of 3,800 megawatts. In the longer run the company is planning on reaching 500 megawatts of demand response by 2021, which would make demand response equal to 11.4 percent of its 2021 forecasted peak demand of about 4,400 megawatts.

Portland General Electric expects to have 125 megawatts of dispatchable standby generation (DSG) in place by 2012. While this generation is licenced to operate 400 hours per year, PGE is using it to provide contingency reserves, which means it only operates when another resource is unexpectedly unavailable, or a much smaller number of hours per year. PGE also has received

[18] Power Forward is a program coordinated with the governor's office in Utah that makes public service announcements asking for voluntary reductions from the general public when the power system is stressed. Estimated response varies, but has been as much as 100 megawatts.

[19] Instead of having reductions on fixed schedules, some customers on Monday, some on Tuesday, etc., the company would be able to call on all of the participating customers at the same time when the need arises.

responses from a Request for Proposals (RFP) asking for proposals to provide demand response up to 50 megawatts by 2012. These responses make the company confident that it can actually secure 50 megawatts of new demand response by 2012. PGE also has 10 megawatts that is interruptible. The sum of these three resources, 185 megawatts, is equal to 4.1 percent of the company's projected peak load of 4,500 megawatts in 2012.

Elsewhere in the country, the New York Independent System Operator (NYISO) has been enlisting and using demand response in its operations for several years. The NYISO currently has about 2,300 megawatts of demand response participating in their programs. About 2,000 megawatts of that total are subject to significant penalties if they don't deliver promised reductions when called upon, so should be considered firm resources. About 300 megawatts of the total are voluntary and are better counted as nonfirm, although the typical response of these resources is around 70 percent, according to NYISO staff. The 2,000 megawatts of firm demand response amount to about 5.9 percent of the NYISO's expected 2009 peak load of 34,059 megawatts. Adding the expected 70 percent of the 300 megawatts of non firm demand response would raise the expected total demand response to 2,210 megawatts, or 6.5 percent of peak load.

The New England Independent System Operator (ISO-NE) cites 1,678 megawatts of demand response without dispatchable standby generation and 2,278 megawatts of demand response with dispatchable standby generation in 2007. These figures are 6.1 and 8.3 percent of ISO-NE's average weather summer peak load of 27,400 megawatts, (winter 22,775 megawatts).[20]

PJM Interconnection (PJM) is a Regional Transmission Organization that manages a wholesale market and the high-voltage transmission system for 13 mid-Atlantic Coast and Midwest states and the District of Columbia. PJM estimates 4,460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts[21] or about 3.2 percent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, and Kentucky) that is not included in this total.

California dispatched 1,200 megawatts of interruptible load on July 13, 2006, to help meet a record peak load of 50,270 megawatts. California had 1,200 megawatts more of DR available if it had been needed.[22] The 2,400 megawatts of total demand response used and available amounted to 4.8 percent of actual peak load. By 2011 the three investor-owned utilities expect to have at least 3,500 megawatts of demand response available, or 6.5 percent of the California Energy Commission's forecast of the three utilities' peak loads total for 2011 (53,665 megawatts).[23]

## *Portfolio Analysis of Demand Response in the Sixth Plan*

In the development of the Sixth Power Plan, staff considered possible refinements in the treatment of demand response in the portfolio model. The fifth plan treated demand response

[20]http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf Table 5-7 page 47, Table 5-8 page 49, and Table 3-3 pg 25

21 http://www.pjm.com/documents/~/media/documents/presentations/pjm-summer-2008-reliability-assessment.ashx

[22] "Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets" Markets Committee of the ISO/RTO Council October 16, 2007

[23] The California Energy Commission's forecast of the three utilities peak demands can be found at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF, in the Form 4 table for each utility.

very much like a peaking generator, with especially low fixed costs and high variable costs, but available at all times for as many hours per year as necessary. In fact most demand response is not available at all times (e.g. demand response from irrigation pumping is only available in the summer,) and there is generally some fairly low number of hours that customers are willing to tolerate reduced service. To better reflect this reality, the sixth plan analyzed demand response programs that are only available seasonally and have a maximum number of hours per season they can be exercised.

The analysis also simulated more than one kind of demand resource program, which will allow examination of the effect of demand response programs with varying proportions of fixed and variable costs on system costs and risks.

## Council Assumptions

Based on the studies of demand response potential and experience elsewhere described above, the Council adopted cost and availability assumptions for several demand response programs. For this analysis of long-term planning strategies, the assumptions lean more toward the comprehensive end of the “precise/comprehensive” spectrum. These assumptions were used in the regional portfolio model to analyze the impact on expected system costs and risk of alternative resource strategies. Accordingly, they can be regarded as achievable technical potential, with the portfolio model analysis determining the programs and amounts that are cost- and risk- effective.[24]

The Council based its assumptions in part on the evidence that demand response of at least 5 percent of peak load has been accomplished by a number of utilities and system operators in periods of five to ten years, so that accomplishing a similar level of total demand response over 20 years in our region is reasonable. The total assumed potential brackets the 5 percent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,550 megawatts in the winter and 1,750 megawatts in the summer (about 3.9 percent and 4.4 percent of the forecast 40,000 megawatt peak load forecast for 2030, respectively). With dispatchable standby generation, the totals are 2,550 megawatts in the winter and 2,750 megawatts in the summer, or 6.4 percent and 6.9 percent of forecast peak load, respectively.

The assumptions are summarized in Table H-1. Two points are worth making about these assumptions: First, they include demand response that has already been achieved, amounting to more than 160 megawatts by 2009. Second, they include announced plans to acquire demand response by regional utilities amounting to more than 350 megawatts.

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own characteristics that determine the demand response available in that area. Further, while the allocation of the total potential to individual components is reasonable, more experience could well support changes in the allocation.

For example, ALCOA has offered to provide reserves as part of its proposed contract with Bonneville that could provide from about 15 megawatts to over 300 megawatts of demand response, depending on how much aluminum production capacity is operating and the level of

[24] For more information about the working of the portfolio model, see Chapter 9.

compensation.  A complete potline (in the case of the ALCOA Ferndale plant, about 160 megawatts) can be reduced by about 10 percent for an extended time (i.e. about 16 megawatts for a number of hours) or shut down entirely for at least an hour without the risk of the alumina "freezing" in the pots.  If two or more potlines are operating, they can alternate shutting down for an hour, so that load can be reduced by about 160 megawatts on a continuous basis without freezing pots.  The alternating potlines would not have to be at the same plant – the result could be achieved by negotiating the cooperation of other smelter owners (e.g. Columbia Falls Aluminum) and other electricity suppliers to aluminum smelters (e.g. Chelan County Public Utility District).

Cold storage facilities for food are estimated to use about 140 average megawatts of energy in the region and could be interrupted briefly without compromising the quality and safety of food.  These facilities have participated in demand response programs in other regions, with reductions in load of 50 percent at peak load hours.  The large thermal mass of food products stored in these facilities allows them to cut load for hours with minimal change in food temperatures.  The same quality could also allow a form of energy storage by pre-cooling the product slightly below nominal temperatures if the power system has a temporary (i.e. a few minutes or hours) surplus of energy.

As the region gains more experience with as-yet-unexamined resources such as these, the Council will revise its assumptions on potential for demand response.

**Table H-1:  Demand Response Assumptions**

| Program | MW | Fixed Cost | Variable Cost or hours/year Limit | Season available |
|---|---|---|---|---|
| **Air Conditioning (Direct Control)** | 200 | $60/kW-year | 100 hours/year | Summer |
| **Irrigation** | 200 | $60/kW-year | 100 hours/year | Summer |
| **Space heat/Water Heat (Direct Control)** | 200 | $100/kW-year | 50 hours/year | Winter |
| **Aggregators (Commercial)** | 450 | $70/kW-year | $150/MWh<br>80 hours/year | Summer + Winter |
| **Interruptible Contracts** | 450 | $80/kW-year | 40 hours/year | Summer + Winter |
| **Demand Buyback** | 400 | $10/kW-year | $150/MWh | All year |
| **Dispatchable Standby Generation** | 1,000 | $20-$40/kW-year | $175-300/MWh | All year |

The resource programs examined were:

***Direct load control for air conditioning***.  Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common DR programs across the country, and is most attractive in areas where electricity load peaks in the summer.  The Pacific Northwest as a whole is still winter-peaking, but new forecasts show the region's summer peak load growing faster than winter peak load.  PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking load.  The two utilities have acquired and exercised more than 100 peak megawatts of demand response from direct control of air conditioning.  Most of those 100 megawatts are outside the Council's planning region, in Utah.  Air conditioning is increasing in the region as a whole, as is the importance of the summer peak load in the region.  The assumption for the portfolio model analysis is that there will be 200 megawatts of this resource in the region by 2030. Based on PacifiCorp's experience, the resource is assumed to cost $60 per kilowatt a year and to be limited to 100 hours per summer.

1. **Irrigation.** PacifiCorp and Idaho Power are currently reducing irrigation load by nearly 100 megawatts by scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. There is significant irrigation load elsewhere in the region as well. The assumption for the portfolio model analysis is that 200 megawatts of irrigation DR will be available by 2030. Based on PacifiCorp's experience, this resource is assumed to cost $60 per kilowatt a year, limited to 100 hours per summer. Since the adoption of these assumptions for the draft plan, the Council has learned that the planned acquisition of demand response from irrigation by Idaho Power alone would exceed 200 megawatts.

2. **Direct load control of space heat and water heat.** While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited. The assumption for the portfolio model analysis is 200 megawatts, at $100 per kilowatt a year for a maximum of 50 hours per winter. These assumptions are informed by the Global Energy and Brattle Group study for Bonneville. The megawatt assumption is about half the study's estimate for residential and commercial direct control programs when the study's most optimistic result is extended from Bonneville's customers to the whole region.

3. **Aggregators.** Increasingly, aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other. These aggregators are known by a variety of titles such as "demand response service providers" for the independent system operators in New York and New England and "curtailment service providers" for the PJM regional transmission organization. Aggregators could recruit demand response from loads already described here, in which case aggregators would not add to the total of available demand response. But in the Council's analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured in the assumptions. This resource is assumed to be 450 megawatts. The assumed fixed costs of $70 a kilowatt per year and variable costs of $150 per megawatt hour are based on conversations with aggregators. The resource is assumed available for a maximum of 80 hours during the winter or summer.

4. **Interruptible contracts.** Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is an old mechanism for reducing load in emergencies, although in some cases they became de facto discounts with no expectation that the utility would ever actually interrupt service. These contracts are usually arranged with industrial customers, and PacifiCorp has about 300 megawatts of interruptible load under such contracts. The assumption for the portfolio analysis is that 450 megawatts will be available by 2030 at a fixed cost of $80 a kilowatt per year, limited to 40 hours any time during the year. The costs of existing interruptible contracts are considered proprietary, so the Council's cost assumption is based on conversations with aggregators.

5. **Demand buyback.** Utilities with demand buyback programs offer to pay customers for reducing load for hours-long periods on a day-ahead basis. Early in the 2000-2001 energy crisis, Portland General Electric conducted a program that had significant participation. Other utilities were developing similar programs, but the idea of buying back power for several hours a day was overtaken by high prices in all hours, and deals were made that bought back power for months rather than hours (mostly from Direct Service Industries). Since 2001, the most active buyback program has been PacifiCorp's program. Buyback programs still exist elsewhere in principle, but have not been maintained in a ready-to-use state. While this option could be replaced by expanded aggregator programs, the assumption for the Council's portfolio model analysis is that demand buyback programs with customers who deal directly with utilities (not through aggregators) could amount to 400 megawatts by 2030, at fixed costs of $10 a kilowatt per year and variable costs of $150 per megawatt hour available all year. These cost assumptions are based on the experience of Portland General Electric with its Demand Exchange program in 2000-2001.

***Dispatchable standby generation.*** This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electric power even when the grid is down. The generators can also be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not simulated in the portfolio model, but dispatchable standby generation is nevertheless a form of demand response that has significant potential and cannot be overlooked. Portland General Electric has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE has 53 megawatts of dispatchable standby generation available in early 2009, and plans to have 125 megawatts by 2012. This potential will grow over time as more facilities with emergency generation are built and existing facilities are brought into the program. The Council assumes that at least 300 megawatts would be available in PGE's service territory by 2030, and that the rest of the region will have at least twice as much, for a total of about 1,000 megawatts by 2030. Based on Portland General Electric's program, cost assumptions are $20-$40 per kilowatt per year fixed cost and $175-$300 per megawatt-hour variable cost, available all year.

The dispatchable standby generation component was not modeled by the regional portfolio model, since it is expected to be used for contingency reserves, which cannot be represented in the model. The other programs were simulated in the portfolio model, with schedules based on those in Table H-2. The air conditioning and irrigation programs were treated as one program, since their costs and dispatch constraints were identical. That program, the space and water heating program, the aggregator's component, and the interruptible contracts component were modeled similarly. For each of these components, the portfolio model could try:

1. No demand response at all,

2. Demand response on the 2009-2019 schedule in Table H-2 followed by no additional demand response,

3. No demand response for 2009-2019 followed by demand response in 2019-2029 following the 2009-2019 schedule in Table H-2,

4. Demand response for 2009-2029 on the schedule in Table H-2.

Previous analysis with the portfolio model has shown the demand buyback program to consistently reduce costs and risks. It was modeled on the schedule shown in Table H-2.

**Table H-2: Schedule of Demand Response Programs in the Regional Portfolio Model**

| | Megawatts | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Program** | **2009** | **2011** | **2013** | **2015** | **2017** | **2019** | **2021** | **2023** | **2025** | **2027** | **2029** |
| **AC and Irrigation** | 100 | 200 | 230 | 260 | 290 | 320 | 350 | 380 | 400 | 400 | 400 |
| **Space and Water Heat** | | 10 | 20 | 30 | 40 | 50 | 70 | 90 | 120 | 160 | 200 |
| **Aggregators** | | 20 | 60 | 100 | 150 | 200 | 250 | 300 | 350 | 400 | 450 |
| **Interruptible Contracts** | | 50 | 100 | 150 | 200 | 250 | 300 | 350 | 400 | 450 | 450 |
| **Demand Buyback** | 70 | 100 | 130 | 160 | 190 | 220 | 250 | 290 | 340 | 370 | 400 |

### Pricing Structures

The Council is not making assumptions now about the amount of demand response that might be available from pricing structures. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, most residential customers don't yet have them, which makes time-of-day pricing, critical peak pricing, peak time rebates, and real time prices unavailable to those customers for the time being. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There is also the potential for double counting between demand response programs and any pricing strucuture initiatives.

The Pacific Northwest Demand Response Project, co-sponsored by the Council and the Regulatory Assistance Project is taking up the subject of pricing structures as a means of achieving demand response in the spring of 2009. In addition, Idaho Power and Portland General Electric are launching pilot projects for time-sensitive electricity prices, which can be expected to provide valuable experience not only for those utilities but the region as a whole.

## *Providing Ancillary Services with Demand Response*

Demand response has usually been regarded as an alternative to generation at peak load (or at least near peak load), which occur a few hours per year. Because demand response for this purpose is only needed a few hours a year, customers need to reduce their usage for only a few hours a year. The load whose reduction provides such demand response need not be year-round load, as long as the load is present during hours when system load is at or near peaks (the most familiar example is air conditioning load for summer-peaking systems).

But demand response can do more than help meet peak load. It can help provide ancillary services such as "contingency reserves" and "regulation and load following." Historically ancillary services have not been considered a problem in the Pacific Northwest, but as loads have grown, and especially as wind generation has increased, power system planners and operators have become more concerned about ancillary services (see Chapter 12 of this plan). Not all demand response can provide such services, since they have different requirements than meeting peak load.

Ancillary services are not simulated in the Council's Regional Portfolio Model, so the potential value of demand response in this area will not be captured in the model's analysis. Nevertheless, the potential cannot be ignored, and the subject should be pursued as one of the demand response action items.

## Contingency Reserves

In some respects providing contingency reserves with demand response is similar to meeting peak loads with demand response. In both cases load reductions of a few hours per year are likely to meet the system need.[25]

But in other respects providing contingency reserves requires somewhat different demand response than meeting peak loads. To provide contingency reserves during non-peak load hours, demand response will require reductions in end use loads that are present in those hours. For example, residential space heating cannot provide reserves in the summer; residential air conditioning cannot provide reserves in the winter; but commercial lighting and residential water heating can provide contingency reserves throughout the year.

## Regulation and Load Following

Providing regulation and load following with demand response presents new requirements, compared to serving peak loads. Regulation is provided by generators that automatically respond to relatively small but quite rapid (in seconds) variations in power system loads and generation. Load following is provided by larger and slower adjustment in generator output in response to differences between the amount of prescheduled generation and the amount of load that actually occurs. Regulation and load following are needed in virtually every hour of the year, and require that generation be able to both increase and decrease.

Many customers who would be willing to provide demand response for meeting peak loads will not be available for regulation or load following. Providing regulation or load following with demand response would involve decreasing or increasing loads in virtually every hour.[26] Customers who are willing and able to decrease <u>and</u> increase use when the power system needs it will be harder to recruit than those who are willing and able only to decrease loads. Even if customers are asked only to decrease loads, many of them who could participate in, for example, a 100 hour per year demand response program that helps meet peak loads, will not be able participate in a load following program that requires thousands of actions per year.

While demand response that can provide regulation or load following will be a subset of all possible demand response, there may well be a useful amount. What kinds of loads make good candidates for this kind of demand response?

One example would be pumping for municipal water systems. Such systems don't pump continuously -- they fill reservoirs from which water is provided to customers as needed. The

[25] Contingency reserves are only called to operate when unexpected problems make the regularly scheduled resource unavailable, which occurs infrequently. Further, utilities are required to restore reserves within 105 minutes, so that the reserves' hours of operation per occurrence are limited. The result is that actual calls on contingency reserves are likely to be a few hours per year.

[26] It may be possible to achieve an equivalent effect by a combination of loads that can make reductions when necessary together with generation that can make reductions when necessary. One such combination could be DR and wind machines.

schedule of pumping can be quite flexible, as long as the reservoir level remains somewhere between specified minimum and maximum levels. For such a load, the water utility could specify the total amount of pumping for the next 24 hours based on its customers' expected usage, and allow the power system to vary the pumping over the period to help meet variation in the power system's loads (and variation of wind generation), as long as the total daily pumping requirement is satisfied. Presently, accomplishing this degree of coordination between the power system and its customers is probably not practical, but with the Smart Grid's promise of cheaper metering and communication and more automated control, it could become so.

Another example is the charging load for plug-in hybrid cars (PHEVs). Many parties have suggested this possibility, and the general outline of these cars' potential interaction with the power system is common to most proposals -- the PHEVs' individual batteries together act as a large storage battery for the power system whenever they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low (e.g. at night) and gives electricity back to the system when the cost is high (e.g. hot afternoons or during cold snaps). The Smart Grid could coordinate[27] this exchange.

Domestic water heating is yet another example of a load that could be managed to provide regulation or load following to the power system. In this case we have enough information to make a rough estimate of how much flexible reserve could be available. Current estimates of the region's total number of electric water heaters run in the 3.4 million range. If each of these heaters has heating elements of 4,500 watts, the total connected load is about 15,300 megawatts. Of course water heaters are not all on at the same time, but load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5,300 megawatts, depending on the season, day and hour.

In normal operation water heaters' heating elements come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water coming into the tank. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water in the tank is gone. This means that heating the replacement water can be delayed (reducing loads) for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5,300 megawatts, depending on when it is needed.

But to provide regulation or load following, reductions aren't sufficient -- loads need also to be increased when the power system needs it. An example of such a condition is 4:00 AM during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have too much energy and few good options – they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

Water heating can help absorb this temporary surplus of energy and make productive use of it. Water heating loads can be increased up to the maximum connected load, but the duration of the

[27] A common assumption is that this coordination includes a requirement that the charge in the PHEV's battery at the end of the day is sufficient to get home. Even if requirement is not met, however, PHEV's have the ability to charge their own batteries, so they are not stranded.

increase will be limited by the rise in water temperature above its normal setting that we allow. If, for example, we allow the temperature to rise from 120 degrees Fahrenheit to 135 degrees Fahrenheit, 3.4 million 50 gallon water heaters can accept 6,198 megawatt hours of energy, store it (at the cost of roughly 24 megawatt-hours per hour higher standby losses) and return it to the system in the form of a reduction in hot water heating requirement in a later hour.[28]

There are other loads that have some sort of reservoir of "product," a reservoir whose contents can vary within an acceptable range.  The "product" might be crushed rock, compressed and cooled air (in the process of air separation), stored ice (for commercial building air conditioning), pulped wood for paper making, or the like.  This reservoir of "product" could allow the electricity customer to tolerate variation in his rate of electricity use to provide ancillary services to the power system, assuming that the customer receives adequate compensation.

There is an industrial plant in Texas that provides 10 megawatts of regulation to the Electricity Reliability Council of Texas (ERCOT) the independent system operator of the Texas interconnected power system.  ERCOT's rules keep plant information confidential, but it is understood that the plant's process is electrochemical, and that its unique situation makes unlikely that many other plants could provide regulation to the power system.

[28] This rise could result from an increase in load of 6,198 megawatts for an hour, or an increase in load of 3,099 megawatts for two hours, etc.  See Appendix K for a fuller description of providing reserves, load following and energy storage using water heaters.

# Appendix H1: Demand Response

## Guidelines for Cost-effectiveness Valuation Framework for Demand Response Resources in the Pacific Northwest - Pacific Northwest Demand Response Project

### Background

In May 2007, the Pacific Northwest Demand Response Project (PNDRP) agreed to form several Working Groups to explore demand response (DR) issues in more detail (Cost-effectiveness, Pricing, and Integrating DR into Distribution System Planning and Investment). In July 2007, the Cost-Effectiveness Working Group met for a one-day workshop in Portland Oregon, which included presentations by a number of utilities on valuation approaches used for DR resources. In January 2008, draft guidelines for a DR Cost-effectiveness valuation framework were presented and discussed at a Working Group workshop.[29] In September 2008, the draft final guidelines were presented and discussed at a Working Group workshop; participants provided comments and suggestions. At that meeting, there was consensus among participants on the guidelines and that the final guidelines document should be provided to the Northwest Power and Conservation Council to be included as an Appendix in the Sixth Pacific Northwest Power and Conservation Plan. This document offers proposed guidelines for a cost-effectiveness valuation framework for Demand Response Resources that could be considered as a screening tool by state commissions and utilities in the Pacific Northwest.

### Purpose

The primary purposes of a cost-effectiveness valuation framework for DR resources are to:

- Propose workable methods for state commissions, utilities and others to consider for valuing the benefits and costs of different types of DR resources in long-term resource planning;
- Provide methods that can be used in *ex ante* screening of DR programs for cost-effectiveness and to evaluate the treatment of a portfolio of DR resources/program options in an integrated utility resource plan;
- Document value of demand response for the purpose of rate setting.

### Demand Response Resources

- Demand Response resources (DRR) are comprised of flexible, price-responsive customer loads that may be curtailed or shifted in the event of system emergencies and system operational needs or when wholesale market prices are high.
- It is useful to characterize Demand Response resources in terms of their “firmness” as a resource option from the perspective of the utility.
- Firm DSM Resources (Class 1)

[29] The Draft Guidelines were developed based on discussions among participants in the PNDRP Cost-effectiveness Working Group and our review of DR valuation studies and cost-effectiveness proceedings currently underway in other jurisdictions (see References).

  - This class of DR resources allows either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time. These resources can include such programmatic options as fully dispatchable programs (e.g. direct load control of air conditioning, water heating, space heating, commercial energy management system coordination) and scheduled firm load reductions (e.g. irrigation load curtailment, thermal energy storage).[30]
- "Non-firm" DSM resources (Class 3)
  - DR resources in this group are typically outside of the utility's direct control and include curtailable rate tariffs, time-varying prices (e.g., real-time pricing, critical peak pricing), demand buyback, or demand bidding programs.

**Guidelines and Principles**

1) Treat DR resources on par with alternative supply-side resources and include them in the utilities' integrated resource plans and transmission system plans.

2) Distinguish among DR programs with respect to their design purpose, dispatchability, response time, and relative certainty regarding load response (e.g., firmness).

3) In assessing cost-effectiveness of DR resources, it is important to account explicitly for all potential benefits, including avoided/deferred generation capacity costs, avoided energy costs, avoided T&D losses, deferred/avoided T&D grid system expansion, environmental benefits, system reliability benefits, and benefits to participating customers.

4) Incorporate the temporal and locational benefits of DR programs systematically (e.g. estimate avoided costs at hourly level, treat transmission congestion zones separately). Most of the benefits of DR resources are related to avoiding relatively low probability future events (e.g. unusually high peak demand or energy prices) in relatively few hours, whose occurrence could have significant economic consequences.

5) All DR program incentive and administration costs, costs of enabling technology, and participant costs should also be included. For DR programs in which customers have to voluntarily enroll, it can be assumed that total costs incurred by participants are less than or equal to the benefits, otherwise they would be unlikely to sign up and participate.[31]

6) DSM programs are often screened using a set of benefit-cost tests that compare and assess the benefits and costs from different perspectives (i.e., society, utility, participants,

[31] For participants, benefits include bill reductions and any financial incentives paid, tax credits (if available) and non-energy benefits; costs include capital and O&M costs associated with installation of DR enabling technologies, the value of service lost (e.g. reduced productivity and/or comfort), and transaction costs. As a practical matter, this means that for a voluntary DR program, utilities can assume that the benefit/cost values for the Participant Test are greater than one.

and non-participants).[32] These tests are not intended to be used individually or in isolation; results from the various tests should be compared and trade-offs between tests considered.[33] These benefit-cost tests may need to be modified and adapted in some areas to account for the distinctive characteristics and features of DR resources.

7) Utilities should consider conducting sensitivity analysis on key benefit and cost variables that have significant uncertainties which can have a major impact on program cost-effectiveness (see an Excel workbook with illustrations of the proposed cost-effectiveness screening method at: http://www.nwcouncil.org/energy/powerplan/6/final/AppendixH2.xls).

8) Initiate and conduct DR pilot programs to assess market readiness, barriers to customer participation and to obtain information on customer performance that can be used to characterize the timing and duration of load impacts for long-term resource planning. Pilot programs need to include exercises of "non-firm" DR resources with a view to identifying a fraction of the resource that could be treated as firm for planning purposes.

**Benefits of DR Resources**

1) Avoided Generation Capacity Costs
    a. "Firm" DR resources, when directly incorporated into a utility's resource and reliability planning processes, can avoid the need for a relatively high heat rate generating capacity. The market value of that type of generating capacity will typically be based on a new natural gas-fired combustion turbine (CT).
    b. There is not a consensus on methods to determine the market value of new generating capacity avoided by a DR resource. Some parties in the Pacific Northwest have raised concerns about the appropriate way to value capacity when the region is long on power.[34] Moreover, market prices for new capacity are not widely available.
    *c.* In the interim, using a benchmarking method that estimates the costs of a new gas-fired CT as a proxy to derive the market value of avoided generation capacity is a reasonable approach for screening DR programs.[35] *These costs have typically been estimated to range between $50-85 per kW-year in the past, but recent increases in costs have resulted in estimates of over $100 per kW-year.*

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[32] See *California Standard Practice Manual Economic Analysis of Demand Side Programs and Projects, October 2001* as one example. http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

[33] PUCs and utilities may consider using the Total Resource Cost (TRC) or Societal Test as the primary test in screening DR programs.

[34] Similarly, in California, the investor-owned utilities have proposed to offset the present value of the total fixed costs of that new CT by the present value of the gross margins that the new CT capacity is expected to earn from selling energy when wholesale electricity market prices exceed variable costs. Other parties in California (e.g. industrial customers) disagree with the method proposed by the California utilities.

[35] In estimating CT costs, utilities should annualize total investment using a real economic carrying charge rate that takes into account return, income taxes, and depreciation, with O&M, ad valorem and payroll taxes, insurance, costs associated with obtaining firm gas transmission, and capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants.

d. Estimates of hourly market prices for new generation capacity can be derived by allocating the estimated annual market price of generation capacity ($/kW-yr) among the hours in each year, in proportion to the relative need for generation capacity in each hour. Utilities, regulators, and other stakeholders should agree on method(s) to allocate avoided generation capacity costs to specific time periods that is appropriate for the Pacific Northwest power system.[36]
e. Avoided T&D losses and Reserve margin -- The resulting estimates of generation capacity costs avoided by DR program should be adjusted upward to reflect the T&D line losses avoided by that DR resource capacity and the capacity planning reserve margin avoided by that DR program.[37]
f. The capacity benefits of a DR resource should also be adjusted for differences that reflect operational program constraints (e.g., limits on the months, days, and/or hours in which DR program events can be called; limits on maximum duration of program events, limits on number of consecutive days on which program events can be called) compared to the capacity value of a new CT (including limits on the use of a CT).

2) Avoided Energy Costs
   a. DR resources typically result in load shifting from peak to off-peak periods or load curtailments in which customers forego consumption for relatively short time periods. Thus, DR resources also enable utilities to avoid energy costs.
   b. Because utilities can always buy or sell electricity in the wholesale energy market, the expected wholesale market electricity price in each future time period is the relevant opportunity cost for estimating the value of electricity that will be avoided by a DR resource.
   c. Avoided energy costs should be adjusted upward to reflect distribution system line losses that DR load reductions would avoid in event hours.
   d. Avoided energy costs can be particularly important in evaluating DR programs from the participants' perspective as they tend to directly affect customer bills.
   e. DR program events are most likely to be called in hours when prices are higher than expected; using expected hourly prices will tend to under-estimate actual electricity market prices in the hours in which an event-based DR program is called and will reduce loads.
   f. Avoided energy costs may be estimated using several options: (1) wholesale energy prices averaged over the highest priced hours of a price forecast, and (2) stochastic methods (e.g., Monte Carlo simulations) that analyze the correlation between electricity prices and times that DR events are expected to occur and explicitly address the uncertainty in future loads, prices, hydro conditions in the Pacific Northwest regional utility system.

3) Deferred Investments in Transmission and/or Distribution System Capacity
   a. The transmission and distribution system is comprised of three key elements: interties, local network transmission, and local distribution systems.

[36] In California, the utilities have proposed allocating the annual market value of new CT capacity to individual hours in proportion to the loss of load expectation (LOLE) in each hour.
[37] T&D losses will typically be higher during peak periods compared to average values for T&D losses.

b. DR programs that provide highly predictable load reductions on short notice may allow utilities to defer and/or reduce transmission and/or distribution (T&D) capacity investments in specifically defined congested locations on the grid. This may lead to a reduction in a utility's projected T&D capital budget and thus avoid some T&D costs.[38]
c. Utilities should consider one of two options in estimating avoided T&D costs: (1) develop a default avoided T&D cost which may be applied to DR programs that meet pre-established criteria regarding locational value and certainty of load reductions or (2) estimate avoided or deferred T&D capacity investments on a case specific basis.[39]
d. The default avoided T&D costs can be calculated by using marginal costs associated with local transmission and distribution substation equipment, which is principally related to transformer capacity.[40]

4) Environmental Benefits (and Costs)
   a. DR resources have the potential to produce environmental benefits by avoiding emissions from peaking generation units as well as some potential conservation effects (i.e. through load curtailments, foregoing usage).
   b. Assessing the environmental impacts of DR resources depends primarily on the emissions profile of the utility's generation resource mix as well as participating customer's DR strategy (e.g., load curtailment vs load shifting vs onsite generation).
   c. For DR resources that result in load curtailments, a reasonable proxy for estimating the volume of greenhouse gas (GHG) emissions avoided by a DR resource is to base it on the operating and emission rate characteristics of a new CT.

5) Reliability Benefits
   a. DR resources can provide value in responding to system contingencies that compromise electric system operator's ability to sustain system level reliability and increase the likelihood and extent of forced outages.
   b. In the context of long-term resource planning, joint consideration of economic (avoided capacity and energy) benefits and reliability benefits is challenging. In an IRP plan, the value of DR hinges primarily on its ability to displace some portion of the utility's peak demand. Once DR resources are included in the utility's projected capacity resource mix, they become part of planned capacity and are no longer available for dispatch during system emergencies.

[38] The extent to which DR programs may defer or avoid specific T&D capital investments depends on: 1) the characteristics of the individual utility system, 2) the specific T&D investment proposed, 3) the characteristics of the customer load to be served by the proposed T&D investment, 4) the attributes of the proposed DR program, and 5) the level of uncertainty associated with the projected load impacts of the DR program.
[39] The specified criteria for DR programs are designed to limit application of avoided T&D costs to DR programs that: (1) are located in areas where load growth would result in need for additional delivery infrastructure, (2) are capable of addressing local delivery capacity needs, (3) have sufficient certainty of providing long-term reduction that the risk to utility of incurring after-the-fact distribution system replacement costs is modest, and (4) can be relied upon for local T&D equipment loading relief.
[40] Marginal T&D costs often include local T&D lines, towers and power poles, underground conduit and structures which are added as service is extended into new geographic areas; these costs are generally not related to peak demands in a specific area and are typically not avoided by a DR program.

   c. Customers participating in emergency or other “non-firm” DR programs are not counted on as system resources for planning purposes; they represent an additional resource for reliability assurance; distinct from “firm” DR programs that are counted among planned reserves.[41]
   d. In assessing the value of these emergency-type DR programs, a reasonable proxy for monetizing the value of load curtailments is the product of the value of lost load (VOLL) with typical values between $3-5/kWh and the expected un-served energy (EUE).[42]

6) “Hard to quantify” benefits
   a. Some potential benefits of demand response are inherently difficult to quantify. Examples of “hard to quantify benefits” include: the long-term educational value of customers being exposed to and having a choice of how to respond to time-varying wholesale market prices or customer satisfaction in helping to avert system emergency. These non-quantifiable benefits are likely to be small but state PUCs may also want to consider them in assessing dynamic pricing (if appropriate).

**DR Resource Costs**

7) Program Administration Costs
   a. Utilities will incur initial and ongoing costs in operating DR programs. Incremental program costs attributable to DR resources can include program management, marketing, customer education, on-site hardware, customer event notification system upgrades, and payments to third party curtailment service providers that implement aspects of a DR program.

8) Customer costs
   a. Customer costs are defined as those costs incurred by the customer to participate in a DR program and can include investments in enabling technology to participate, developing a load response strategy, comfort/inconvenience costs, rescheduling costs for facility workers, or reduced product production.
   b. For a voluntary DR program, it is reasonable to assume that participant costs are less than or equal to the incentives offered by the program; otherwise most customers would not voluntarily chose to participate.[43] The exceptions are those customers who believe participation is the right thing to do, regardless of their personal costs

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[41] Emergency DR programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources have been deployed and reserve margins still cannot be maintained, curtailments under an emergency DR program reduce the likelihood and extent of forced outages.

[42] Expected unserved energy (EUE) is a measure of the magnitude of a reserve shortfall which takes into account the change in the likelihood of curtailment (i.e. loss of load probability) and the amount of load at risk.

[43] One possible exception are those customers that are motivated by civic responsibility and believe that participation in a DR program and responding to a electric power system emergency are the “right thing” to do, regardless of their personal costs.

9) Incentive payments to participating customers
    a. Incentive payments are paid to customers participating in DR programs to encourage them to enroll initially and continue in the program. Incentives also compensate customers for any reduction in the value of service that they would normally receive (e.g. higher household temperatures during an A/C cycling event or increased costs when a business shuts down some of its equipment when an emergency event is called).
    b. For voluntary DR programs, in evaluating cost-effectiveness, it is reasonable to assume that total customer costs incurred by participants will be equal to the present value of incentives expected to be paid.[44]

10) Characterizing DR Resource Costs
    a. It is reasonable to ramp up enrollment in DR programs over a multi-year period (e.g. 3-4 years) and to match the time horizon of DR costs and benefits (e.g. use expected life of DR enabling technology in assessing benefits).
    b. In modeling DR program options, it is useful to categorize costs into fixed expenses (program development, ongoing administration, communication and data acquisition infrastructure) and variable costs (e.g. incentive payments to customers, participant acquisition costs, other program costs that vary with number of participants or the number of times that DR program events are called).).

11) Relationship between DR screening and portfolio analysis
    a. A long-term resource plan that includes a portfolio analysis and accounts for the uncertainties in future loads, prices, and resources, is the preferred approach to fully value the benefits of DR resources
    b. In screening DR resources and program concepts, it is also useful to establish cost-effectiveness thresholds that allow regulators and utilities to estimate whether a DR program is worthwhile to pursue.

**References on DR Cost-effectiveness and Valuation**

U.S. Department of Energy (2006). “Benefits of DR in Electricity Markets and Recommendations for Achieving them: A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005,” February 2006.

Quantec 2006. “Demand Response Proxy Supply Curves,” prepared for Pacificorp, September 8, 2006.

CPUC (2007). “Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-effectiveness Methodologies, Megawatt Goals and Alignment with California System Operator Market Design Protocols,” OIR 07-01-041, Jan 25, 2007.

[44] It is reasonable to treat incentive payments in voluntary DR programs as compensation for any loss of service or out of pocket costs that participating customers expect to incur under the assumption that the customer would not participate if the incentive wasn’t sufficient to offset these costs.

CPUC Energy Division (2008). *Draft Demand Response Cost-effectiveness Protocols.* April 4, 2008.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (2007). *Revised Straw Proposals For Demand Response Load Impact Estimation and Cost Effectiveness Evaluation*, September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf)

Joint Comments of California Large Energy Consumers Association, Comverge, Inc., Division of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Ice Energy, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and The Utility Reform Network (2007). *Recommending a Demand Response Cost Effectiveness Evaluation Framework*, September 19, 2007 (http://docs.cpuc.ca.gov/efile/CM/75556.pdf).

# Appendix H1-A

## Examples of Cost Effectiveness Screening Methodology

We have constructed two prototypical demand response programs - a direct load control water heater program and a smart thermostat air conditioning program – in a spreadsheet-based tool to illustrate how the Cost Effectiveness screening methodology may be applied to specific demand response programs.[45] . The spreadsheet tool includes "typical" first-year values and compound annual growth rates for key model inputs on costs and load impacts; LBNL established "typical" values for key inputs based on our analysis of reference values (i.e., minimum, average, median, and maximum values) observed in pilot and full-scale DR program evaluations from the Pacific Northwest and a review of the DR program planning and evaluation literature. Users of the spreadsheet tool have the capability to change model inputs based on their assessment of appropriate model input values for DR programs under consideration and can use the Reference Values as a guide to the range of values observed in the Pacific Northwest.

**Direct Load Control – Water Heater**

This program targets single-family residential customers with standard-sized electric water heaters. A control switch is installed in each participant's home near the water heater circuit breaker, which is then controlled via a one-way pager signal to trip the relay on and off according to the received message. Curtailments are initiated during peak hours of winter weekdays (i.e., mornings and/or afternoons) and are not expected to exceed sixty hours each year (i.e., fifteen events at four hours/event). A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events. We assume an average event performance rate of 95% for this DLC program (i.e., 5% of the customer switches fail to respond).

Figure A-1 summarizes information on market penetration, aggregate load impacts, economic and reliability benefits, and costs of the DLC Water Heater program. The utility expects to ramp up the DR program over a seven-year period with the goal of achieving 30,000 participants. With per unit savings expected to be 1.0 kW during events, the program is anticipated to reduce the residential class peak demand by 1.6% when it reaches steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%). In terms of energy savings, it is anticipated that the water heater DLC program will have a small impact on energy usage during peak periods when events are called (60 kWh/unit-year), which is completely made up in the four-hour period following a curtailment.

The utility has budgeted $100,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are ~$25/customer for marketing and back-office costs, that cost and installation of the switch is $175/customer, and that load impact verification costs are $5/customer (e.g. cost and installation of a logger for a sample of customers). The utility will also offer customers an incentive for participating in events ($6.66/month bill credit for three months = $20/customer-year). The use of the one-way paging system is expected to cost the

[45] See spreadsheet entitled "DR_Cost_Effectiveness_Methodology_Model_Public~112508.xls"

utility $7/customer-year, while the utility believes it will incur $10/customer-year to inspect a sample of switches and loggers as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $60,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings. No reliability benefits are calculated because this resource is considered “firm”, and thus is directly integrated into the planning process. The utility projects that in 2008 the value of avoided cost of peak and off-peak energy is 7.5 ¢/kWh and 4.5 ¢/kWh respectively, which is projected to increase at 2% per year. Environmental benefits are estimated to be $0.008/kW-year, increasing 2% annually. The first year avoided cost of capacity is set at $80/kW-year, and is expected to increase by 3% a year thereafter. T&D savings can be broken out into two pieces: line loss savings and reduced investment in plant. The utility has a secondary voltage level loss factor of 6%, thus any associated reduction in sales and peak demand means 106% of that electricity need not be generated and maintained for reserves, respectively. The utility has deemed that the average T&D cost savings associated with the program are $3/kW-year, which grows at an annual rate of 3%. Avoided capacity benefits account for ~95% of total benefits of the water heater DLC program. Because the DLC program is treated as a “firm” resource and is credited with avoiding and/or deferring a supply-side resource, we do not include additional reliability benefits.

Using these inputs and assuming the DLC water heater program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.63MM and program benefits to be $25.12MM. This water heater DLC program produces $5.49MM in net benefits with a TRC benefit-cost ratio of 1.28.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity and T&D (initial year value and assumed escalation rate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

## Figure A-1 – Direct Load Control Water Heater Demand Response Program: Benefit-Cost Estimates

| Year Index | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| ***Utility System Characteristics*** | | | | | | | | | | | | | | | | | | | | |
| Forecasted Retail Sales (GWh) | 23,000 | 23,460 | 23,929 | 24,408 | 24,896 | 25,394 | 25,902 | 26,420 | 26,948 | 27,487 | 28,037 | 28,598 | 29,170 | 29,753 | 30,348 | 30,955 | 31,574 | 32,206 | 32,850 | 33,507 |
| Forecasted Peak Demand (MW) | 4,000 | 4,088 | 4,178 | 4,270 | 4,364 | 4,460 | 4,558 | 4,658 | 4,761 | 4,865 | 4,972 | 5,082 | 5,194 | 5,308 | 5,425 | 5,544 | 5,666 | 5,791 | 5,918 | 6,048 |
| Residential Retail Sales (GWh) | 8,740 | 8,915 | 9,093 | 9,275 | 9,460 | 9,650 | 9,843 | 10,040 | 10,240 | 10,445 | 10,654 | 10,867 | 11,084 | 11,306 | 11,532 | 11,763 | 11,998 | 12,238 | 12,483 | 12,733 |
| Residential Peak Demand (MW) | 1,520 | 1,553 | 1,588 | 1,623 | 1,658 | 1,695 | 1,732 | 1,770 | 1,809 | 1,849 | 1,890 | 1,931 | 1,974 | 2,017 | 2,061 | 2,107 | 2,153 | 2,200 | 2,249 | 2,298 |
| ***DR Program Characteristics*** | | | | | | | | | | | | | | | | | | | | |
| Number of New Participants (Units) | 4,286 | 4,586 | 4,886 | 5,186 | 5,486 | 5,786 | 6,086 | 2,760 | 2,821 | 2,883 | 2,946 | 3,011 | 3,077 | 3,145 | 3,214 | 3,285 | 3,357 | 3,431 | 3,506 | 3,584 |
| Number of Returning Participants (Units) | 0 | 3,986 | 7,971 | 11,957 | 15,943 | 19,929 | 23,914 | 27,900 | 28,514 | 29,141 | 29,782 | 30,437 | 31,107 | 31,791 | 32,491 | 33,206 | 33,936 | 34,683 | 35,446 | 36,226 |
| Number of Total Participants (Units) | 4,286 | 8,571 | 12,857 | 17,143 | 21,429 | 25,714 | 30,000 | 30,660 | 31,335 | 32,024 | 32,728 | 33,448 | 34,184 | 34,936 | 35,705 | 36,490 | 37,293 | 38,114 | 38,952 | 39,809 |
| Peak Period Energy Reduction (MWh) | 244 | 489 | 733 | 977 | 1221 | 1466 | 1710 | 1748 | 1786 | 1825 | 1866 | 1907 | 1949 | 1991 | 2035 | 2080 | 2126 | 2172 | 2220 | 2269 |
| Off-Peak Period Energy Increase (MWh) | 244 | 489 | 733 | 977 | 1221 | 1466 | 1710 | 1748 | 1786 | 1825 | 1866 | 1907 | 1949 | 1991 | 2035 | 2080 | 2126 | 2172 | 2220 | 2269 |
| Proportion of Class Retail Sales (%) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Capacity Reduction (MW) | 4.07 | 8.14 | 12.21 | 16.29 | 20.36 | 24.43 | 28.50 | 29.13 | 29.77 | 30.42 | 31.09 | 31.78 | 32.48 | 33.19 | 33.92 | 34.67 | 35.43 | 36.21 | 37.00 | 37.82 |
| Proportion of Class Peak Demand (%) | 0.3% | 0.5% | 0.8% | 1.0% | 1.2% | 1.4% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% | 1.6% |
| ***Benefits*** | | | | | | | | | | | | | | | | | | | | |
| Avoided Energy Cost Savings ($MM) | $0.01 | $0.02 | $0.02 | $0.03 | $0.04 | $0.05 | $0.06 | $0.06 | $0.07 | $0.07 | $0.07 | $0.08 | $0.08 | $0.08 | $0.09 | $0.09 | $0.09 | $0.10 | $0.10 | $0.11 |
| Avoided Capacity Cost Savings ($MM) | $0.35 | $0.71 | $1.10 | $1.51 | $1.94 | $2.40 | $2.89 | $3.04 | $3.20 | $3.37 | $3.54 | $3.73 | $3.93 | $4.13 | $4.35 | $4.58 | $4.82 | $5.07 | $5.34 | $5.62 |
| Avoided T&D System Cost Savings ($MM) | $0.01 | $0.03 | $0.04 | $0.05 | $0.07 | $0.08 | $0.10 | $0.11 | $0.11 | $0.12 | $0.13 | $0.13 | $0.14 | $0.15 | $0.15 | $0.16 | $0.17 | $0.18 | $0.19 | $0.20 |
| Environmental Benefits ($MM) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Reliability Benefits ($MM) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| ***Total ($MM)*** | ***$0.37*** | ***$0.75*** | ***$1.16*** | ***$1.60*** | ***$2.05*** | ***$2.54*** | ***$3.05*** | ***$3.21*** | ***$3.38*** | ***$3.55*** | ***$3.74*** | ***$3.94*** | ***$4.14*** | ***$4.36*** | ***$4.59*** | ***$4.83*** | ***$5.08*** | ***$5.35*** | ***$5.63*** | ***$5.93*** |
| ***Benefits - Present Value ($MM)*** | **$25.12** | | | | | | | | | | | | | | | | | | | |
| ***Costs*** | | | | | | | | | | | | | | | | | | | | |
| Program Development Costs ($MM) | $0.10 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Customer Acquisition Costs ($MM) | $0.88 | $0.96 | $1.04 | $1.13 | $1.22 | $1.31 | $1.40 | $0.65 | $0.68 | $0.71 | $0.74 | $0.77 | $0.80 | $0.83 | $0.87 | $0.91 | $0.94 | $0.98 | $1.03 | $1.07 |
| Annual Program Administration Costs ($MM) | $0.06 | $0.06 | $0.06 | $0.06 | $0.06 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.08 | $0.08 | $0.08 | $0.08 | $0.08 | $0.08 | $0.09 | $0.09 |
| Annual Program Variable costs ($MM) | $0.16 | $0.32 | $0.49 | $0.67 | $0.86 | $1.05 | $1.25 | $1.30 | $1.36 | $1.42 | $1.48 | $1.54 | $1.60 | $1.67 | $1.74 | $1.82 | $1.89 | $1.97 | $2.06 | $2.15 |
| ***Total ($MM)*** | ***$1.20*** | ***$1.34*** | ***$1.60*** | ***$1.86*** | ***$2.14*** | ***$2.43*** | ***$2.72*** | ***$2.02*** | ***$2.11*** | ***$2.19*** | ***$2.29*** | ***$2.38*** | ***$2.48*** | ***$2.58*** | ***$2.69*** | ***$2.80*** | ***$2.92*** | ***$3.04*** | ***$3.17*** | ***$3.30*** |
| ***Costs - Present Value ($MM)*** | **$19.63** | | | | | | | | | | | | | | | | | | | |
| ***Net Benefits ($MM)*** | ***5.49*** | | | | | | | | | | | | | | | | | | | |
| ***Benefit Cost Ratio*** | ***1.28*** | | | | | | | | | | | | | | | | | | | |

**Smart Thermostat – Air Conditioning Program**

This smart thermostat program targets single-family residential customers with central air conditioning system. A smart thermostat is installed in each participant's home, replacing the existing thermostat, which is then controlled via a one-way pager signal to manage the set-point and cycling of the furnace. Curtailments are initiated during peak hours of summer (June - August) weekday afternoons and are not expected to exceed one-hundred twenty hours each year (i.e., thirty events of four hours/event). Due to the cycling strategy undertaken coupled with a customer's ability to override the set-point signal, it is assumed that about 65% of the households participate during events. A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events.

Figure A-2 summarizes projected market penetration, aggregate load impacts, economic and reliability benefits, and costs for the smart thermostat air conditioning program. The utility expects to ramp up the smart thermostat program over a seven-year period, with the goal of achieving 30,000 participants. With per unit savings expected to be 1.1 kW during events, the program is anticipated to reduce the residential class peak demand by 1.2% when it reaches a steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%)). The utility estimates that increasing set-points and cycling the air conditioner will have a measurable impact on energy consumption during events (132 kWh/unit-year). The utility also assumes that customers will take back about 50% of these energy savings during the four hour period following a curtailment.

The utility has budgeted $150,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are $30/customer for marketing and back-office costs, that cost and installation of the smart thermostat is $175/customer, and that load impact verification costs are $5/customer. Costs for the smart thermostat are assumed to decrease by 1.5% per year, due to technology improvements and greater market volumes. The utility will offer customers an incentive for participating in events ($7/month bill credit for three months = $21/customer-year). The use of the paging system is expected to cost $5/customer-year, while the utility believes it will incur $15/customer-year to inspect a sample of smart thermostats and interval meters as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $65,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings (see discussion of water heater DR program). The avoided capacity costs account for ~90% of the total benefits.

Using these inputs and assuming the smart thermostat air conditioning program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.28MM and program benefits to be $19.91MM. The TRC Benefit Cost ratio for this program would be slightly above 1.0 and is only marginally cost-effective.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity (initial year value and assumed escalation rate) and the assumed proportion of customers that participate and respond to events and don't override (e.g. we assume 65% participate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

## Figure A-2 – Smart Thermostat Air Conditioning Demand Response Program: Benefit-Cost Estimate

| Year Index | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| ***Utility System Characteristics*** | | | | | | | | | | | | | | | | | | | | |
| Forecasted Retail Sales (GWh) | 23,000 | 23,460 | 23,929 | 24,408 | 24,896 | 25,394 | 25,902 | 26,420 | 26,948 | 27,487 | 28,037 | 28,598 | 29,170 | 29,753 | 30,348 | 30,955 | 31,574 | 32,206 | 32,850 | 33,507 |
| Forecasted Peak Demand (MW) | 4,000 | 4,088 | 4,178 | 4,270 | 4,364 | 4,460 | 4,558 | 4,658 | 4,761 | 4,865 | 4,972 | 5,082 | 5,194 | 5,308 | 5,425 | 5,544 | 5,666 | 5,791 | 5,918 | 6,048 |
| Residential Retail Sales (GWh) | 8,740 | 8,915 | 9,093 | 9,275 | 9,460 | 9,650 | 9,843 | 10,040 | 10,240 | 10,445 | 10,654 | 10,867 | 11,084 | 11,306 | 11,532 | 11,763 | 11,998 | 12,238 | 12,483 | 12,733 |
| Residential Peak Demand (MW) | 1,520 | 1,553 | 1,588 | 1,623 | 1,658 | 1,695 | 1,732 | 1,770 | 1,809 | 1,849 | 1,890 | 1,931 | 1,974 | 2,017 | 2,061 | 2,107 | 2,153 | 2,200 | 2,249 | 2,298 |
| ***DR Program Characteristics*** | | | | | | | | | | | | | | | | | | | | |
| Number of New Participants (Units) | 4,286 | 4,586 | 4,886 | 5,186 | 5,486 | 5,786 | 6,086 | 2,760 | 2,821 | 2,883 | 2,946 | 3,011 | 3,077 | 3,145 | 3,214 | 3,285 | 3,357 | 3,431 | 3,506 | 3,584 |
| Number of Returning Participants (Units) | 0 | 3,986 | 7,971 | 11,957 | 15,943 | 19,929 | 23,914 | 27,900 | 28,514 | 29,141 | 29,782 | 30,437 | 31,107 | 31,791 | 32,491 | 33,206 | 33,936 | 34,683 | 35,446 | 36,226 |
| Number of Total Participants (Units) | 4,286 | 8,571 | 12,857 | 17,143 | 21,429 | 25,714 | 30,000 | 30,660 | 31,335 | 32,024 | 32,728 | 33,448 | 34,184 | 34,936 | 35,705 | 36,490 | 37,293 | 38,114 | 38,952 | 39,809 |
| Peak Period Energy Reduction (MWh) | 368 | 735 | 1103 | 1471 | 1839 | 2206 | 2574 | 2631 | 2689 | 2748 | 2808 | 2870 | 2933 | 2998 | 3063 | 3131 | 3200 | 3270 | 3342 | 3416 |
| Off-Peak Period Energy Increase (MWh) | 184 | 368 | 552 | 735 | 919 | 1103 | 1287 | 1315 | 1344 | 1374 | 1404 | 1435 | 1467 | 1499 | 1532 | 1565 | 1600 | 1635 | 1671 | 1708 |
| Proportion of Class Retail Sales (%) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Capacity Reduction (MW) | 3.06 | 6.13 | 9.19 | 12.26 | 15.32 | 18.39 | 21.45 | 21.92 | 22.40 | 22.90 | 23.40 | 23.92 | 24.44 | 24.98 | 25.53 | 26.09 | 26.66 | 27.25 | 27.85 | 28.46 |
| Proportion of Class Peak Demand (%) | 0.2% | 0.4% | 0.6% | 0.8% | 0.9% | 1.1% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% | 1.2% |
| ***Benefits*** | | | | | | | | | | | | | | | | | | | | |
| Avoided Energy Cost Savings ($MM) | $0.02 | $0.04 | $0.06 | $0.09 | $0.11 | $0.14 | $0.16 | $0.17 | $0.18 | $0.18 | $0.19 | $0.20 | $0.21 | $0.22 | $0.22 | $0.23 | $0.24 | $0.25 | $0.27 | $0.28 |
| Avoided Capacity Cost Savings ($MM) | $0.26 | $0.54 | $0.83 | $1.14 | $1.46 | $1.81 | $2.17 | $2.29 | $2.41 | $2.53 | $2.67 | $2.81 | $2.96 | $3.11 | $3.27 | $3.45 | $3.63 | $3.82 | $4.02 | $4.23 |
| Avoided T&D System Cost Savings ($MM) | $0.01 | $0.02 | $0.03 | $0.04 | $0.05 | $0.06 | $0.08 | $0.08 | $0.09 | $0.09 | $0.09 | $0.10 | $0.10 | $0.11 | $0.12 | $0.12 | $0.13 | $0.14 | $0.14 | $0.15 |
| Environmental Benefits ($MM) | $0.00 | $0.00 | $0.00 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 |
| Reliability Benefits ($MM) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| ***Total ($MM)*** | ***$0.29*** | ***$0.60*** | ***$0.92*** | ***$1.27*** | ***$1.63*** | ***$2.02*** | ***$2.42*** | ***$2.55*** | ***$2.68*** | ***$2.82*** | ***$2.96*** | ***$3.12*** | ***$3.28*** | ***$3.45*** | ***$3.63*** | ***$3.82*** | ***$4.02*** | ***$4.23*** | ***$4.45*** | ***$4.68*** |
| ***Benefits - Present Value ($MM)*** | $19.91 | | | | | | | | | | | | | | | | | | | |
| ***Costs*** | | | | | | | | | | | | | | | | | | | | |
| Program Development Costs ($MM) | $0.15 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Customer Acquisition Costs ($MM) | $0.90 | $0.95 | $1.00 | $1.04 | $1.08 | $1.13 | $1.17 | $0.52 | $0.52 | $0.53 | $0.53 | $0.54 | $0.54 | $0.54 | $0.55 | $0.55 | $0.55 | $0.56 | $0.56 | $0.56 |
| Annual Program Administration Costs ($MM) | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.07 | $0.08 | $0.08 | $0.08 | $0.08 | $0.08 | $0.08 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 | $0.09 |
| Annual Program Variable costs ($MM) | $0.18 | $0.36 | $0.55 | $0.75 | $0.95 | $1.16 | $1.39 | $1.44 | $1.51 | $1.57 | $1.64 | $1.71 | $1.78 | $1.85 | $1.93 | $2.01 | $2.10 | $2.19 | $2.28 | $2.38 |
| ***Total ($MM)*** | ***$1.29*** | ***$1.37*** | ***$1.61*** | ***$1.86*** | ***$2.11*** | ***$2.36*** | ***$2.63*** | ***$2.04*** | ***$2.11*** | ***$2.18*** | ***$2.25*** | ***$2.32*** | ***$2.40*** | ***$2.48*** | ***$2.56*** | ***$2.65*** | ***$2.74*** | ***$2.84*** | ***$2.93*** | ***$3.04*** |
| ***Costs - Present Value ($MM)*** | $19.28 | | | | | | | | | | | | | | | | | | | |
| ***Net Benefits ($MM)*** | ***0.63*** | | | | | | | | | | | | | | | | | | | |
| ***Benefit Cost Ratio*** | ***1.03*** | | | | | | | | | | | | | | | | | | | |

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# INTRODUCTION

This appendix describes the development of the planning assumptions for new generating resources for use in the Sixth Power Plan. The first part describes conventions, the approach to the development of capital cost estimates, and calculation of levelized costs. The second section describes the development of certain data and assumptions such as resource incentives, carbon sequestration costs, and transmission and integration costs that are applied to more than one resource type. The final section describes the development of assumptions for the reference power plants used to characterize the various generating resources considered for the power plan, and the estimates of developable resource potential.

# GENERAL APPROACH AND ASSUMPTIONS

## *Conventions*

The following conventions are used in this Appendix and in Chapter 6:

***Price Year:*** The price year from which future changes in real costs are calculated is 2008.

***Year Dollars:*** Costs are expressed in constant 2006 dollars.

***Technology Base Year:*** The technology base year from which future changes in technology are calculated is 2008.

***Project Scope:*** The scope of resource cost estimates includes the cost of project development, construction, operation and decommissioning, integration costs for variable resources, the cost and losses of transmission to the wholesale receiving point of a load-serving entity and the mean value forecasted cost of carbon dioxide ($CO_2$) allowances.

***Heat Rate:*** Heat rates are full load, net plant lifetime averages, expressed as higher heating value.

***Total Plant Cost:*** Capital costs are expressed in overnight (instantaneous) Total Plant Costs. "Total Plant Costs" are the sum of direct and indirect engineering, procurement, and construction (EPC) costs, plus Owner's Costs in constant 2006 year dollars. Owners costs include non-EPC costs incurred by the project developer, such as permits and licenses, land and right-of-way acquisition, social justice costs, project development costs, legal fees, owners engineering, project and construction management staff, startup costs, site infrastructure (transmission, road, water, rail, waste water disposal, etc.), taxes, spares, furnishings and working capital. Not included in Total Plant Cost are financing costs, escalation incurred during construction (EDC), and interest incurred during construction (IDC). These are separately calculated in the Council's analyses to yield total investment cost.

***Total Investment Cost:*** Total investment cost includes the cost of securing financing, IDC, and EDC for a specified service year and plant owner.

## *Capital Cost Estimates*

The capital cost estimates for the reference power plants are based on published sources. These include preconstruction estimates and as-built costs reported in the media, PUC filings and other documents for specific projects, and generic cost estimates for specific technologies and projects appearing in publically-available reports. Using this information, the Council develops an estimate of per-kilowatt Total Project Costs for each reference plant

The raw cost data used to develop reference plant cost estimates represent different vintages, project scope, and year dollars, and may or may not include the costs of financing, escalation, and interest during construction. In some cases, highly detailed, disaggregated cost estimates are available, in other cases only a single number. Reported costs must be normalized to a common vintage, scope, year dollars, and to overnight value. This is especially important for this plan because of the rapid escalation of construction costs from 2004 to mid-2008 and the subsequent softening of costs because of the economic situation. The information needed to make these adjustments is usually documented in technology assessments and feasibility studies. However, the needed information is often incomplete or entirely missing in media reports, necessitating assumptions. The general approach used to normalize costs is as follows; additional detail regarding specific technologies is provided in the respective technology sections.

- Project capacity is adjusted to common metrics. For thermal projects this is net output under ISO conditions. Wind project costs are based on installed turbine capacity and utility-scale solar project costs are adjusted to net AC output.

- Reported estimates were adjusted to represent a plant configuration approximating the reference plant. Plants having configurations highly unrepresentative of the reference plant were eliminated from the samples. For example, reported costs for simple-cycle combustion turbine plants consisting of more than four units were omitted. In other cases, costs were increased or decreased to adjust for major design characteristics. For example, the reported cost of thermal plants with dry cooling was adjusted downward to represent the cost of plants employing evaporative cooling.

- Estimates were adjusted to include all owner's costs (project development, land, infrastructure and financing). Unless otherwise noted in the source, cost estimates reported prior to completion are assumed to be overnight construction cost, exclusive of owner's costs. These were increased to account for owner's costs. Reported costs for completed plants are assumed to include all owner's costs.

- Costs reported for specific locations were adjusted to an average construction cost index for the Pacific Northwest states using the state civil adjustment factors of USACE (2008).

- Costs were adjusted to represent overnight costs. Cost estimates reported prior to completion are assumed to be total plant costs so were not adjusted other than conversion to constant (real) 2006 dollars. Reported costs for completed projects are assumed to be total investment costs in as-expended (nominal). For these cases, the equivalent overnight total plant costs in year 2006 dollars are calculated using the Council's MicroFin project financing and levelization model.

Because of the substantial escalation in plant construction costs between 2004 and 2008, it is necessary to plot costs by vintage to gain a sense of representative 2008 price year. Costs of completed plants or plants under construction are assumed to represent costs as of the initial year of construction (i.e., fixed price EPC contracts). The vintage of costs reported for plants not yet under construction is assumed to be the year of publication. Some resources, particularly those where large samples are available and with plants of uniform design yielded well-defined distributions. Figure I-18 (wind plants) is one such example. In cases with well-defined distributions, the representative 2008 base year cost was taken as the approximate average of 2008 costs and the range of normalized reported costs (less obvious outliers).

Other resources yielded poorly-defined distributions because of small sample sizes, plants with widely varying characteristics, or for other reasons. An example is I-4, landfill gas energy recovery projects. In these cases, the selection of the reference plant base year cost was influenced by the source and apparent quality of individual samples and the shape of the IHS Cambridge Energy Research Associates Power Capital Cost Index[1] (converted to real terms).

Capital costs forecasts are based on the interaction of two factors - near-term declines resulting from contraction of the credit market and reduction in demand for goods since mid-2008, and, over the longer-term, the effect of technological improvements and economies of production, particularly for less-mature technologies. In general, capital costs (in real terms) are assumed to drop from mid-2008 highs to market equilibrium values by 2011. Market equilibrium values are assumed to be the average of 2004 and 2008 capital costs (in 2006 constant year dollar values). Further declines resulting from technological advances and economies of production are based on rates observed in the years prior to 2004. These assumptions are described below for the various reference plants.

## *Project Financing*

Power plants can be constructed by investor-owned utilities, consumer-owned utilities and independent power project developers. Each of these entities uses different project financing mechanisms. The differing financing mechanisms and financial incentives available for some

[1] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429

resources result in different total investment costs and annual capital service requirements for otherwise identical projects. In general, financing by consumer-owned utilities results in lower capital service requirement than financing by either investor-owned utilities or independent developers. The objective of the Council's plan is to choose among types of resources rather than to recommend the development of specific resources. For this reason, a single type of resource developer is chosen to provide consistent comparisons of resource costs. Investor-owned utility financing is used as the basis in this power plan.

Plant investment costs are calculated using the Council's MicroFin model. MicroFin is a spreadsheet model used to calculate annual and levelized lifecycle minimum revenue requirements for various resources. Accelerated depreciation is normalized for investor-owned utility financing. Investment and production tax credits are credited as available against project costs. MicroFin is used by the Council to calculate levelized electricity costs for broad comparisons among resource alternatives, to calculate levelized fixed costs required to model new resource option in the AURORA$^{xmp®}$ model and to calculate the levelized cost of the three phases of development and construction (Option, Early Construction, and Committed Construction) required for the Regional Portfolio Model. Though investor-owned utility financing is used as the standard for this plan, MicroFin can also model typical consumer-owned utility financing and non-third party independent power developer financing. Operation of MicroFin is further described in the Levelized Cost section, below.

The financing parameter values used in MicroFin are shown in Table I-1.

**Table I-1: Assumptions regarding financing and other common parameters (Values are nominal unless stated)**

| | Municipal/ PUD | Investor-Owned Utility | Independent Power Producer |
|---|---|---|---|
| Federal Income Tax Rate | -- | 35% | 35% |
| Federal Investment Tax Credit | -- | See Incentives | See Incentives |
| FIT Recovery Period | -- | See Incentives | See Incentives |
| State Income Tax Rate | -- | 5.0% | 5.0% |
| State Investment Tax Credit | -- | None | None |
| SIT Recovery Period | -- | Same as federal | Same as federal |
| Property Tax | 1.4% | 1.4% | 1.4% |
| Insurance | 0.25% | 0.25% | 0.25% |
| Debt Term | Economic life | Economic life | 15 years max |
| Equity return | -- | Economic life | 15 years max |

| | Municipal/ PUD | Investor-Owned Utility | Independent Power Producer |
|---|---|---|---|
| Debt fraction - Development | 100% | 50% | 0% |
| Debt fraction - Construction | 100% | 50% | 60% |
| Debt fraction - Term | 100% | 50% | 60% |
| Debt interest - Development | 5.1% | 7.1% | -- |
| Debt interest - Construction | 5.1% | 7.1% | 5.8% |
| Debt interest - Term | 5.1% | 7.1% | 7.1% |
| Return on Equity - Development | -- | 10.2% | 13.7% |
| Return on Equity - Construction | -- | 10.2% | 13.7% |
| Return on Equity - Term | -- | 10.2% | 13.7% |
| Debt Financing Fee | 2.0% | 2.0% | 2.0% |
| Discount Rate | 1.75% | 5.5% | 5.8% |
| General Inflation Rate | 1.7% (2008 - 30 average) | | |

## *Incentives*

Existing federal energy production tax credit and investment tax credit are assumed to apply to qualifying resources for their currently authorized term. Existing provisions for accelerated depreciation are assumed to continue indefinitely. Numerous complexities and options are present in the tax code with respect to these incentives and simplifications are made here, for example, the "tax credit appetite" of the developing entity is not assumed to be limited. No conversions to investment tax credit are taken. Assumptions regarding federal incentives are provided in Table I-2.

**Table I-2: Assumptions regarding federal incentives (2006 year dollar values)**

| Resource | PTC[2] (Alternative to ITC) | ITC[3] (Alternative to PTC) | Accelerated Depreciation Recovery Period[3] |
|---|---|---|---|
| Biomass (Open loop) | $9.85/MWh thru 2013 | None | 7-year |
| CHP[4] (OL Biomass) | $9.85/MWh thru 2013[5] | 10% thru 2016[6] | 5-year |

[2] The federal production tax credit is generally available for the first ten years of operation.
[3] Investment tax credit and accelerated depreciation may be limited to only a portion of total plant investment. In this plan the credits are assumed to apply to the entire investment.
[4] Including waste heat energy recovery.

| Resource | PTC[2] (Alternative to ITC) | ITC[3] (Alternative to PTC) | Accelerated Depreciation Recovery Period[3] |
|---|---|---|---|
| CHP[4] (NG) | None | 10% thru 2016[6] | 5-year |
| Geothermal | $19.70/MWh thru 2013 | 10% (no expiration date) | 5-year |
| Hydropower[7] | $9.85/MWh thru 2013 | None | 20-year |
| Solar | $9.85/MWh thru 2013 | 30% thru 2016, 10% thereafter | 5-year |
| Wind | $19.70/MWh thru 2012 | None | 5-year |

State incentives represent within-region income transfers and are not considered in calculating project costs[8].

## *Levelized Costs*

The levelized production costs appearing in this appendix are forecast costs in constant 2006 year dollars, levelized over the anticipated economic life of the plant. The costs include:

- plant costs (plant development and construction, operation, maintenance, fuel, and byproduct credits)
- integration costs (regulation and load following)
- transmission costs and cost of transmission losses
- carbon dioxide allowance (emission) costs

The following general assumptions are used for calculating levelized costs of capacity and energy:

- Reference plant configuration and location
- Investor-owned utility financing
- Medium fuel price forecast
- Delivery to a load-serving entity, including the cost of transmission losses.
- Plant capacity and heat rate are degraded to the maintenance-adjusted forecast average for the economic life of the plant where this information is available.

---

[5] Denied if investment tax credit is taken (26 USC ¶ 48(c)(3).
[6] Tests regarding size, net thermal efficiency and percentage energy to electrical and non-electrical loads apply to CHP facilities (26 USC ¶ 48(c)(3).
[7] Qualifications apply.
[8] This treatment is not entirely consistent with the treatment of state taxes. These also represent within-region income transfer. Omitting state taxes, however, would eliminate a fairly significant cost that is in-theory applicable to all resources.

- Federal production and investment tax credits as currently authorized

- Accelerated depreciation for federal income tax purposes

Renewable energy credits and state incentives are excluded. . Actual project costs may differ, to a greater or lesser degree, from the costs appearing here because of factors including site-specific conditions, incentives, financing, and timing.

Levelized electricity costs for a given resource and technology may vary by initial year of service because of the forecast changes in fuel prices, carbon dioxide allowance costs, and system integration costs. Forecast changes in capital costs due to technological improvements and production economies will also affect costs through time. A particularly significant effect is the current decline in construction costs for many resources because of the tight credit market and weak economy

The cost of transmission for remote resource options requiring new long-distance transmission assumes no network credit for the transmission improvements. Network credit could reduce transmission costs for these alternatives.

Levelized lifecycle energy and capital costs are computed using the Council's MicroFin revenue requirements model. MicroFin, an Excel spreadsheet model, is used to compute levelized capital costs for new resource options for the AURORA$^{xmp®}$ Electric Market Model and for the Council's Regional Portfolio Model. An overview of the operation of MicroFin is as follows:

> Total project investment is calculated for the selected year of construction using the estimated total plant cost, plant capacity, cost escalation factors, construction cash flow estimates and the construction financing of the selected type of project developer. Consumer-owned utility, investor-owned utility and independent project developer financing options are available in MicroFin. Most resource costs reported in this plan assume investor-owned utility financing.
>
> Annual capital-related costs (debt interest, debt principal, return on equity, recovery of equity, and state and federal taxes) are calculated for the total project investment using the long-term financing characteristics and tax obligations of the selected type of developer. Financial incentives such as accelerated depreciation, investment tax credit, and production tax credits are applied at this point.
>
> Annual property tax and insurance payments are calculated based on depreciated plant value.
>
> Annual energy production is calculated based on plant capacity and capacity factor.
>
> Annual fixed fuel costs are calculated based on escalated fixed fuel costs and plant capacity. Annual variable fuel costs are based on escalated variable fuel costs, heat rate, and energy production.
>
> Annual fixed O&M costs are calculated based on escalated fixed O&M costs and plant capacity. Annual variable O&M costs are based on escalated variable O&M costs and energy production.

Annual emission costs are calculated based on fuel consumption, fuel carbon content, and forecast $CO_2$ allowance costs.

Annual transmission costs are calculated based on plant capacity and escalated unit transmission costs. Integration costs are calculated based on forecast integration costs and energy production.

The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

The net present value for the initial year of service is calculated for each component of annual cost over the life of the project. The levelized annual cost stream yielding the same net present value is then calculated for each component. The discount rate used for the net present value and levelization is the weighted after-tax cost of capital for the selected type of project developer.

The resulting levelized cost components are converted to unit (per-megawatt-hour) values, discounted to the base year (2006 dollar values) and summed to yield total revenue requirements.

A copy of MicroFin, with the resource, fuel financing, and other assumptions used to calculate investment costs and project revenue requirements for this plan is available from the Council upon request.

# GENERAL FORECASTS

## *Transmission*

The common point of reference for the costs of generating resources and energy efficiency measures is the wholesale delivery point to local load-serving entities (e.g., the substation interconnecting a local utility to the regional transmission network). The costs and losses of transmission from the point of generating project interconnection to the wholesale point of delivery are included in estimated generating resource cost. The avoided cost and avoided losses of distribution are credited to energy efficiency resources in the Council's analyses.

The cost of resources serving local loads (e.g., Oregon and Washington resources serving Oregon and Washington loads) include local (in-region) transmission costs and losses. The cost of resources serving remote loads (e.g., Montana resources serving Oregon and Washington loads) include the estimated cost and losses of needed long-distance transmission plus local transmission costs and losses.

### Local transmission costs and losses

Local transmission costs are based on the 2010 Bonneville Power Administration Transmission and Ancillary Service Rate Schedules (BPA 2009). The representative local transmission cost is an approximation of the long-term firm point-to-point service (PTP) rate plus required Ancillary Services and Control Area Services (ACS) rates (scheduling system control and dispatch, reactive supply and voltage control, regulation and frequency response, spinning reserve, and supplemental reserve). The estimated fixed component is $17/kW/yr and the variable component is $1.00/MWh (2006 dollars). The estimated cost of regulation and load-following required to integrate variable generation is separately included, as described in the following section. Local transmission losses are assumed to be 1.9% (BPA 2008, Schedule 9).

### Transmission to access remote resources

The cost of long-distance transmission to access remote resources is based upon the estimated cost of actual proposed new long-distance transmission alignments serving the resource areas of interest (Table I-3). The costs and losses associated with each route were estimated using an adaptation of the Options Analysis Tool developed by the Northwest Transmission Assessment Committee (NTAC) Canada-Northwest-California (C-N-C) study group (NTAC, 2006). Distances and general configuration (AC or DC, voltage, substations with and without transformation, etc.) were estimated from published information regarding the actual proposed transmission projects. The NTAC C-N-C Option Analysis Tool uses representative per mile and per component costs. These were updated and the values are shown in Table I-4. For all cases (except the Colstrip Transmission system upgrade case,[9]) the cost and losses of in-region point-to-point service were added to long-distance transmission costs and losses.

[9] Colstrip upgrade capacity, costs and losses were derived from the NTAC Montana Transmission Study (NTAC, 2005) and included upgrades needed to expand transmission capacity to the I-5 corridor.

**Table I-3: Transmission to access remote resources (2006 year dollar values)**

| Resource & Load Area | Alignment | Point of Injection | Point of Delivery | Configuration | Length (mi) | Substations w/Xformers | Substations w/o Xformers | DC Terminals | Capital Cost (MM$) | Transmission O&M ($/kW/yr) | Losses (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MT Wind to S. ID | MSTI | Townsend, MT | Midpoint, ID | 500kV AC | 415 | 2 | 1 | -- | $1107 | $25.80 | 2.2% |
| MT Wind to OR/WA | MSTI/Gateway W. Seg. 8/B2H | Townsend, MT | Boardman, OR | 500kV AC | 844 | 1 | 5 | -- | $2168 | $50.60 | 4.4% |
| AB Wind to OR/WA | Northern Lights | Milo, AB | Buckley, OR | +/- 500kV DC | 615 | -- | -- | 2 | $1938 | $45.21 | 2.4% |
| WY Wind - S.ID | Gateway W. Segs. 2, 3, 4 & 7 | Aeolus, WY | Cedar Hill, ID | 500kV AC | 471 | 2 | 3 | -- | $1299 | $30.30 | 2.5% |
| WY Wind - OR/WA | Gateway W Segs. 2, 3, 4, 7 & 9/ B2H | Aeolus, WY | Boardman, OR | 500kV AC | 927 | 1 | 7 | -- | $2422 | $56.50 | 5.0% |
| NV Solar - S.ID | WRV - Thirtymile/ SWIP North | White R. Valley, NV | Midpoint, ID | 500kV AC | 370 | 2 | 1 | -- | $1002 | $23.40 | 2.1% |
| NV Solar - OR/WA | WRV - Thirtymile/ SWIP North/Gateway W. Seg. 8/B2H | White R. Valley, NV | Boardman, OR | 500kV AC | 799 | 1 | 5 | -- | $2062 | $48.12 | 4.5% |
| MT Wind to OR/WA | Colstrip Transmission System Upgrade | Judith Basin Area, MT | I-5 Corridor | 500kV AC | -- | -- | -- | -- | $621 | $33.00 | 8.0% |

**Table I-4: Long-distance transmission - Common assumptions (2006$)**

| Item | Value | Source |
|---|---|---|
| O&M (% of overnight capital cost) | 3.5% (exclusive of property tax & insurance) | MSTI |
| 500kV Substation w/Transformation | $51.5 MM (each) | BPA personal communication(2008) |
| 500kV Substation w/o Transformation | $30.0 MM | BPA personal communication(2008) |
| 500kV AC single circuit | $2.0 MM/mi (typical eastside) | BPA personal communication(2008) |
| +/- 500kV DC circuit | $1.97/mi | NTAC C-N-C (2005) |
| 500kV DC Terminal | $242 MM | NTAC C-N-C (2005) |
| 500kV AC capacity | 1500 MW | NTAC C-N-C (2005) |
| +/- 500kV DC capacity | 2000 MW | NTAC C-N-C (2005) |
| +/- 500kV DC losses | 0.115 MW/mi @ 2000 MW | NTAC C-N-C (2005) |
| +/- 500kV DC converter losses | 0.7% | NTAC C-N-C (2005) |
| 500kV AC losses | 0.094 MW/mi @ 1000 MW | NTAC C-N-C (2005) |
| Earliest service | 2015 | |

## *Integration Cost for Variable Resources*

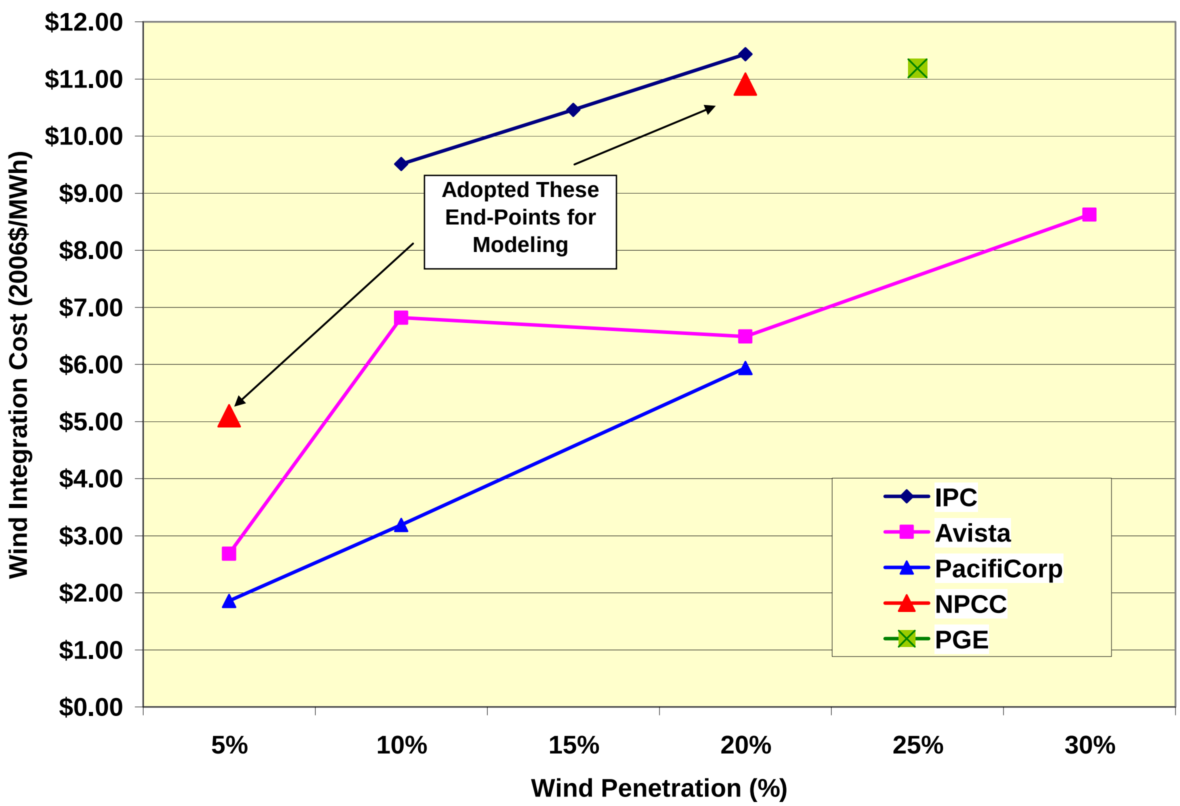
Balancing services (regulation and sub-hourly load-following) for integration of variable output renewable resources such as wind and solar are provided by reserving generating capacity for upward-regulation ("up-reg") and for down-regulation ("down-reg"). Upward-regulation capability is the ability to increase generation to offset unforecasted loss of variable resource output. Down-regulation is the ability to reduce generation to offset unforecasted increases in variable resource output. Unless the variable resource is not operating, or is operating at full output, up-regulation and down-regulation must be provided simultaneously.

The provision of balancing services incurs cost because of foregone revenues or savings. Reserving capacity for up-regulation incurs foregone revenue that would have been received if the reserved capacity could have been profitably dispatched into the market. Reserving capacity for down-regulation incurs cost if the variable cost of the reserved capacity is greater than the market value of power. For these reasons, the cost of providing balancing services is sensitive to the wholesale value of power and the resource used to provide the services. Moreover, the cost of providing balancing services is a function of the penetration of installed variable resource capacity compared to peak load.

Only capacity that is technically and environmentally capable of rapidly responding to changes in load (flexible capacity) is suitable for providing balancing services.  Hydro capacity, though technically extremely flexible and frequently used to provide balancing services, can result in consumption of water, a limited energy source, during periods of  low market value.  An optimal balancing resource is technically and environmentally capable of flexible operation and has variable operating costs close to the market value of power.

The cost of providing balancing services is best estimated with a system impact study where the costs of operating the system with and without a given amount of variable resources are compared.  This type of analysis was not performed for estimating regional variable resource integration costs because of time and modeling considerations.  Rather, an approximate relationship of within-hour balancing costs to wind penetration was subjectively developed from wind integration studies undertaken by various regional utilities (Figure I-1).

**Figure I-1: Wind integration cost estimates as a function of wind penetration from various wind integration studies**




The lower end-point of the proposed regional cost curve represents a cost of about $5.00 per MWh at 2% penetration (currently about 500 MW).  The upper end-point represents a cost of $10.90 at 17% system penetration (currently about 6,000 MW).  For purposes of the initial resource assessment, wholesale price forecasts and resource portfolio model development, penetration (and therefore integration cost) was assumed to be a linear function of time.  The forecast was rebased for the 2010 - 2029 planning period based on an estimated installed regional wind capacity through 2009 of 11%. This yields a 2010 integration cost of $8.85/MWh. The upper end of the integration cost curve ($10.90/MWh) was assumed to be reached in 2024, and run flat in real terms thereafter (Table I-5).

**Table I-5: Forecast regulation and load-following cost and $CO_2$ allowance prices**

| | Regulation and Load-following ($/MWh) | CO2 Allowance Costs ($/tonCO2) |
|---|---|---|
| **2010** | $8.85 | $0.00 |
| **2011** | $8.99 | $0.00 |
| **2012** | $9.14 | $8.05 |
| **2013** | $9.29 | $10.39 |
| **2014** | $9.43 | $13.00 |
| **2015** | $9.58 | $15.14 |
| **2016** | $9.73 | $16.93 |
| **2017** | $9.87 | $19.15 |
| **2018** | $10.02 | $21.70 |
| **2019** | $10.17 | $24.23 |
| **2020** | $10.31 | $26.76 |
| **2021** | $10.46 | $29.15 |
| **2022** | $10.61 | $31.79 |
| **2023** | $10.75 | $34.59 |
| **2024** | $10.90 | $36.85 |
| **2025** | $10.90 | $39.32 |
| **2026** | $10.90 | $41.23 |
| **2027** | $10.90 | $43.29 |
| **2028** | $10.90 | $45.67 |
| **2029** | $10.90 | $46.72 |

## *Carbon Dioxide Allowance Prices*

The mean value of $CO_2$ allowance (or equivalent tax) prices from the Regional Portfolio Model (RPM) studies using the distribution described in Chapter 2 is used for estimating the levelized electricity costs of fossil fuel resources for initial comparisons of resource alternatives. These values are shown in Table I-5.

## *Carbon Dioxide Sequestration*

Numerous possibilities exist for isolating carbon dioxide produced by fossil fuel combustion from the atmosphere for long periods of time. The $CO_2$ from coal-fired power generating facilities is an attractive target for sequestration because power plants are large stationary point sources of $CO_2$, and many plants are located within a feasible transportation distance from potential sequestration sites.

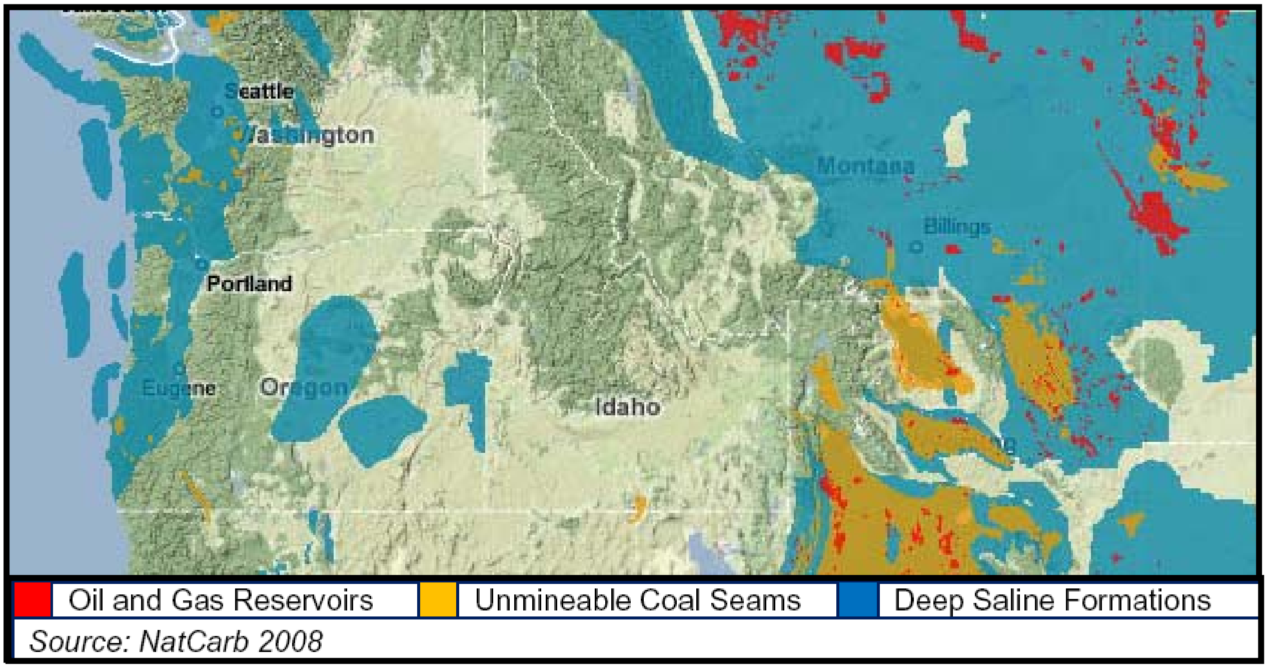
Proposals for long-term storage of $CO_2$ from power plant operation include deep oceanic injection and several geologic mechanisms. The general concept is to separate CO2 at the power plant into a relatively pure form, compress the $CO_2$ to a liquid state, and transport the liquid to the sequestration facility by pipeline for injection.  The pipeline operating pressure would be sufficient for injection without further compression at the sequestration facility.

Oceanic $CO_2$ injection, though feasible, is controversial because of potential impacts on the ocean environment and marine life.  Pilot projects in Hawaii and Norway have been cancelled as a result.  Certain marine treaties now prohibit storage of $CO_2$ in the water column or seabed (IEA, 2008a).  Geologic sequestration options with Northwest potential are described below.  The following discussion is compiled from EcoSecurities (2008), IEA (2004), IEA (2008a) and the Big Sky Carbon Sequestration Partnership (http://www.bigskyco2.org).

**$CO_2$-enhanced oil recovery**:  Carbon dioxide enhanced oil recovery ($CO_2$-EOR) is an established process whereby $CO_2$ is injected into oil fields to enhance recovery of remaining oil.  The $CO_2$ repressurizes the reservoir and promotes release of remaining oil through viscosity reduction and other means.  $CO_2$-EOR has been in commercial use for about three decades and about 3% of current world oil production is recovered using this technology.  $CO_2$ sequestration is incidental to current $CO_2$-EOR operations, the objective of which is profitably recovering oil.  EOR operations undertaken for the purpose of $CO_2$ sequestration would not necessarily operate at a profit, though the value of the recovered oil would help offset overall costs.  An added complexity of a sequestration operation is the need to ensure long-term reservoir integrity. While natural gas and oil reservoirs are inherently of great integrity, developed fields are punctured with wells that if improperly plugged, could release sequestered $CO_2$.  It is believed that enhanced oil recovery using $CO_2$ could eventually be applied to most oil fields, though the $CO_2$ sequestration capacity of depleted oil fields is relatively small compared to $CO_2$ production from power generation facilities.  Scattered oilfields are found in eastern Montana (Figure I-2) and additional opportunities in Alberta, Wyoming, and the Dakotas may be within feasible $CO_2$ transportation distance.

**$CO_2$-enhanced natural gas recovery**: Carbon dioxide enhanced natural gas recovery ($CO_2$-EGR) is a method of augmenting natural gas recovery and of reducing drawdown-related subsidence by repressurizing depleted natural gas fields.  $CO_2$ is denser and more viscous than methane at reservoir conditions so the remaining methane tends to float above the injected $CO_2$. Methane withdrawal could continue until the methane becomes excessively diluted with $CO_2$ that has broken through the overlying methane layer.  A commercial-scale EGR demonstration project is underway in the North Sea, however the technology is not fully developed.  As with CO2-EOR, a major issue is ensuring long-term reservoir integrity. Though the $CO_2$ sequestration potential of EGR might be larger than that of EOR, the economics are less favorable because of the lower revenue from the recovered methane per ton of injected $CO_2$.

**Figure I-2: Potential CO2 storage sites in the Northwest (www.natcarb.org)**



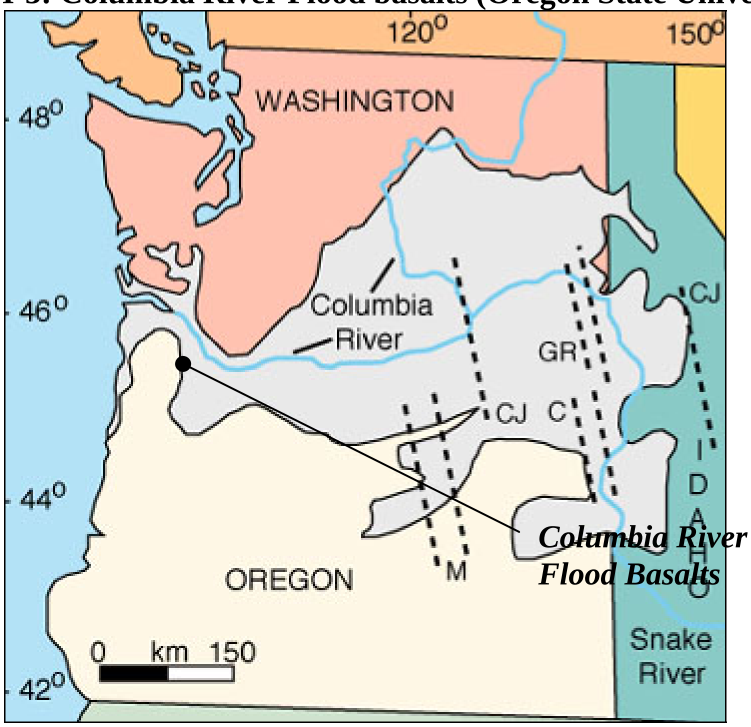

**Depleted oil or gas fields**: Carbon dioxide could be sequestered in depleted oil or gas fields using $CO_2$-EGR injection technology. The global theoretical potential for sequestering $CO_2$ in depleted oil and gas fields is of the same order of magnitude as for $CO_2$-EGR. Similar issues regarding resource integrity would be present and net cost would be higher because of the absence of byproduct oil or gas. Existing production wells could be repurposed for $CO_2$ injection.

**$CO_2$-enhanced coal bed methane recovery (ECBM)**: Coal beds typically contain large amounts of methane-rich gas adsorbed to the coal. Because carbon dioxide is preferentially adsorbed to coal, injection of $CO_2$ into deep unmineable coal seams could sequester the $CO_2$ and produce methane as a marketable product. $CO_2$ is physically adsorbed to the coal, increasing confidence in long-term storage integrity. Coal measures potentially offering ECBM potential are scattered within the four states and a substantial area of potential is present in Wyoming (Figure I-2). The effectiveness and economic feasibility of enhanced coal bed methane recovery using $CO_2$ injection is promising but has yet to be fully demonstrated.

**Deep saline aquifers**: Deep saline aquifers consisting of porous rocks saturated with brine are found throughout the world, many located in the same sedimentary basins from which coal and other fossil fuels are extracted. The brines are of high salt content and typically unsuitable for agricultural use or human consumption. If confined by underlying and overlying layers of restricted permeability these formations may be suitable for long-term storage of very large quantities of $CO_2$. Though initially accumulating under the cap rock, the injected CO2 is expected to eventually dissolve in the brine, promoting secure long-term storage. Deep saline formations are located below the coalfields of eastern Montana and between the Cascades and the coast (Figure I-2). The technical feasibility of $CO_2$ storage in deep saline aquifers has been demonstrated in the North Sea. Remaining questions relate to the amount of $CO_2$ that can be injected into a given aquifer volume, the long-term expansion and migration of the CO2 plume, and the geochemical reactions expected to occur over time.

**Flood basalt formations**: The Columbia River flood basalts and possibly other basalt formations present a potential CO2 sequestration option of particular interest to the Northwest. Flood basalts consisting of several hundred individual flows, each tens to hundreds of feet in thickness, cover the central Columbia Basin and extend to the Pacific along the course of the Columbia River (Figure I-3). Many of the individual flows consist of a fractured and highly porous upper layer and a dense impermeable lower layer. Carbon dioxide could be stored in the porous upper layer, trapped between the dense lower layers of the same flow and the adjacent overlying flow. Preliminary experiments indicate that carbon dioxide would be rapidly converted to solid carbonaceous minerals in the basaltic environment, ensuring permanent storage.

**Figure I-3: Columbia River Flood basalts (Oregon State University)**




The U.S. DOE Regional Carbon Sequestration Partnerships and the National Carbon Sequestration Database and Geographical Information System are assessing the potential for carbon sequestration for individual U.S. states and Canadian provinces. Results are published and periodically updated in the *Carbon Sequestration Atlas of the United States and Canada* (USDOE, 2008). The top section of Table I-6 shows the current estimates of technical sequestration potential for the four Northwest states for three types of formations potentially suitable for $CO_2$ sequestration. The values in this section are from the *Carbon Sequestration Atlas.* To provide perspective regarding this potential, the lower section of the table expresses the technical potential in terms of the number of years of $CO_2$ storage potential at the estimated $CO_2$ production rate from Northwest coal-fired power plants in 2005. Practical storage potential is likely to be much less than the theoretical potential. This suggests that though sequestration in oil and gas reservoirs and unminable coal seams is, in general, technically more advanced than sequestration in deep saline formations, and moreover, may yield marketable oil or gas to help offset sequestration costs, deep saline formations appear to be the principal candidate for sequestration of significant amounts of $CO_2$ over the long-term.

**Table I-6: Theoretical storage potential of several Northwest $CO_2$ sequestration options**

| | Oil and Gas Reservoirs | Unmineable Coal Seams | Deep Saline Formations |
|---|---|---|---|
| **Technical Potential (MM tonsCO2)** | | | |
| ID | 0 | Not reported | Not reported |
| MT | 1388 | 322 | 291,948 -1,087,714 |
| OR | 0 | Not reported | 18,400 - 73,600 |
| WA | 0 | 3080-3395 | 99,270 -397,077 |
| Total | 1388 | 3402 | 409,617 -1,558,391 |
| **Technical Potential (Years @ 2005 CO2 production rate)** | | | |
| ID | 0 | -- | -- |
| MT | 28 | 7 | 6000 - 22,000 |
| OR | 0 | -- | 400 - 1500 |
| WA | 0 | 63 - 69 | 2000 - 8,000 |
| Total | 28 | 70 - 76 | 8300 - 32,000 |

The overall cost of carbon dioxide separation and sequestration includes the incremental capital and operating costs of the power plant facilities for separation and compression of $CO_2$, including the effects of additional electrical and steam loads on plant heat rate, the capital and operating costs of transporting the compressed, liquified $CO_2$, and the capital and operating costs of the sequestration facility, including long-term monitoring of reservoir integrity. The incremental costs and heat rate penalty for power plants with $CO_2$ separation are included in the description of the reference coal-fired power plants in the Assumptions for Reference Plants section of this appendix.

The estimated cost of transporting CO2 from power plant to sequestration facility ranges from $1 - $8/tonne CO2 ($0.90 - $7.20/ton) (EcoSecurities, 2008). The estimated cost of sequestering CO2 in depleted oil fields ranges from $0.50 - $4.00/tonne CO2 ($0.45 - $3.30/ton) and in depleted gas fields from $0.50 - $12.00/tonne CO2 ($0.45 - $10.90/ton) (EcoSecurities, 2008). Storage in deep saline aquifers is estimated to cost from $0.40 - $4.50/tonne CO2 ($0.36 - $4.10/ton) (EcoSecurities, 2008).

For purposes of this plan, CO2 transportation costs are assumed to average $4.00/ton CO2 - an approximation of the $1 - 8/tonne $CO_2$ range cited in EcoSecurities (2008). CO2 transportation is a mature technology and current cost estimates should be a reliable indicator of actual future costs. While appealing because of the potential revenue from recovered oil and gas, any serious attempt to reduce atmospheric releases of $CO_2$ would appear to quickly overwhelm the available capacity of partially depleted oil or gas fields in the Northwest. Sequestration in deep saline formations currently appears to be the most promising candidate for large-scale sequestration in the Northwest. The concept is in the early stages of development, however, and experience with developing technologies suggests that costs are bound to rise much higher than current estimates as the concept is commercialized. For this reason, the Council assumes $CO_2$ sequestration costs average $22.50/ton $CO_2$, the high end of the $15 - 25/tonne $CO_2$ overall North American cost range cited in IEA (2008a).

A commercial-scale deep saline sequestration facility in the Northwest is assumed to be available for operation no earlier than 2023. Given the research, development and demonstration needed to resolve remaining technical issues, the legal and institutional questions needing resolution and the development and construction time required for a commercial-scale CO2 sequestration facility and transportation pipelines, such a facility may not be feasible within the planning period.

# ASSUMPTIONS FOR REFERENCE PLANTS

## *Landfill Gas Energy Recovery*

A landfill gas energy recovery plant uses the methane content of the gas produced as a result of the decomposition of landfill contents to generate electric power. The complete recovery system includes an array of collection wells, collection piping, gas cleanup equipment, and one or more generator sets, usually using reciprocating engines. Typically, the gas collection system is installed as a requirement of landfill operation and the raw gas sold to the operator of the power plant.

***Reference Plant:*** The reference plant consists of two 1.6 MW reciprocating engine generating unit fuelled by landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse and maintenance structure, and power generation site infrastructure.

***Fuel:*** A typical business arrangement is for the power plant operator to purchase the raw landfill gas from the landfill operator. The landfill operator is responsible for installing and operating the wellfield and collection system. The published sources of information regarding landfill gas prices suggest a wide range. Lazard (2008) reports landfill gas fuel costs ranging from $1.50 to $3.00/MMBtu. The Idaho Statesman reports that Ada County collects $0.89/MMBtu plus 40% of REC and PTC credits for the Ada County Landfill Waste-to-Energy plant. The effective fuel price (fuel plus 40% of the value of incentives) for the Ada plant 2007 was $1.50/MMBtu. Because the Ada price lies at the low end of the range reported by Lazard, a somewhat higher expected price, $2.00/MMBtu, is used for this plan - higher than Ada county but towards the low end of the Lazard range.

***Heat rate:*** The heat rate of the reference plant is 10,060 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

Heat Rate (HHV) = $10159x^{-0.0555}$

Where x is the plant capacity in megawatts

***Availability parameters:*** Plant availability parameters are as follows:

Scheduled maintenance - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

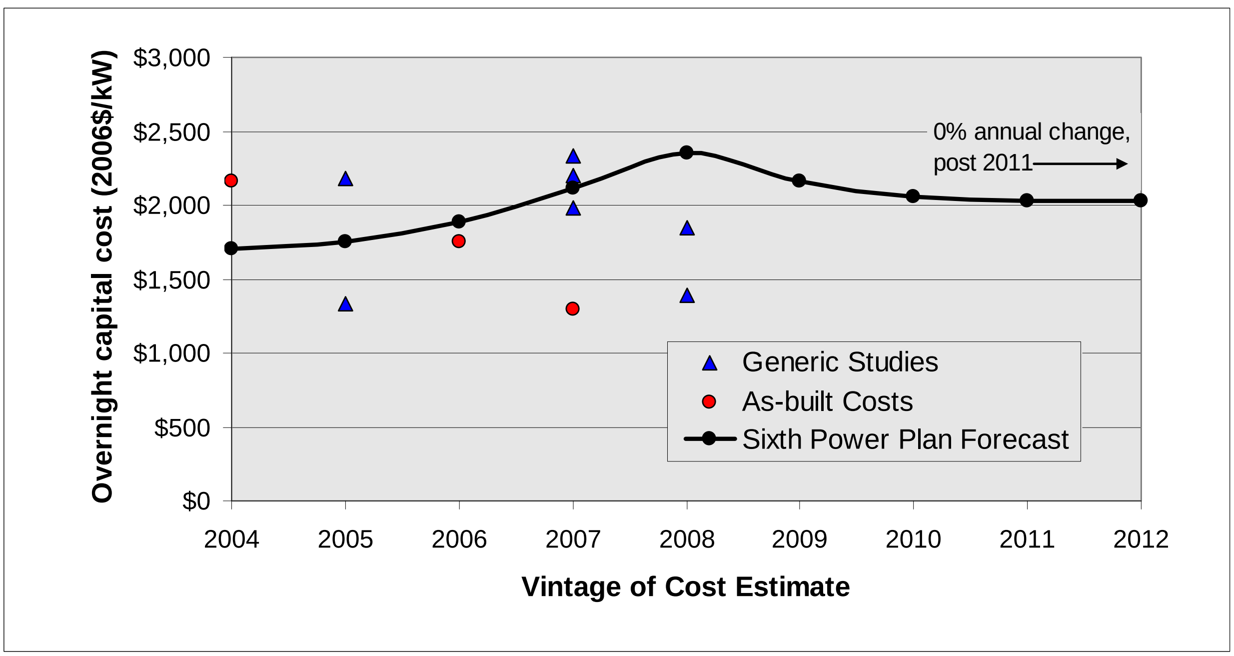
Equivalent annual availability - 88%

***Unit Commitment Parameters*:** Landfill gas energy recovery plants operate as must-run units at an annual capacity factor of 85%, based on CEC (2007).

***Total Plant Cost:*** The "overnight" total plant cost of the reference plant is $2,350/kW installed capacity (2008 price year). This estimate is based on reported as-built costs for three landfill gas energy recovery plants and four generic estimates of plant development costs. Three of the latter were range estimates consisting of low and high bound costs. These cost observations, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-4. The increase in capital costs from 2004 to 2008, observed for most power generation technologies, is not clearly evident here, particularly for the as-built costs. A reason may be that the built projects were of substantially different scopes (e.g., with or without the gas collection system). For this reason, the representative project cost estimate was based on a projection of the 2005 and 2007 generic cost estimates, which together with the 2006 actual project cost seem to reasonably track observed power plant cost escalation during this period. Because landfill gas energy recovery projects were not modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

**Figure I-4: Published and forecast capital costs of landfill gas energy recovery plants**



***Development and Construction Schedule, Cash Flows:*** Development and construction schedule and cash flow assumptions for a landfill gas energy recovery plant are those assumed for reciprocating engine power plants:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3 % of total plant cost
>
> **Early Construction** (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost
>
> **Committed Construction** (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

***Operating and maintenance costs:*** Operating and maintenance costs for landfill gas energy recovery plants were based on California Energy Commission (CEC) estimates. The CEC estimates are consistent with other available estimates of the O&M costs of these plants when adjusted to comparable year dollars. Moreover, the CEC O&M costs are broken into fixed and variable components and exclude property tax and insurance, consistent with the Council's representative resource costs. Fixed O&M cost for landfill gas energy recovery ($26/kW/yr) is estimated to be 1.1% of the overnight capital cost described above. The 1.1% is based on the ratio of fixed O&M cost to overnight cost of Appendix B ("Economic Assumptions: Landfill Gas Fuel to Energy") of CEC (2007). The variable O&M cost ($19/MWh) was derived in a similar manner as 0.8% of total plant cost. Fixed O&M cost assumed to vary in real terms with total plant cost. Variable O&M cost is assumed to remain constant in real terms.

***Economic Life:*** The economic life of a landfill gas energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator and the productive life of a typical landfill.

***Development potential:*** The remaining feasible development potential for landfill gas energy recovery facilities was derived from the U.S. EPA Landfill Methane Outreach Program database of candidate landfills for energy recovery[10]. EPA estimates of waste-in-place in candidate landfills in the four Northwest states were converted to estimated electricity production potential using values for gas generation potential and fuel energy content from an assessment of landfill energy recovery potential in Oregon prepared for the Energy Trust of Oregon (ETO, 2005). The reference plant heat rate of 10,060 Btu/kWh was substituted for the more optimistic heat rate of 9,000 Btu/kWh used in the ETO study. This yielded a remaining undeveloped electric energy potential of 69 average megawatts (Table I-7). This estimate should be viewed as having considerable uncertainty. On one hand, emplaced waste will continue to increase during the planning period, even with aggressive reuse and recycling programs. On the other, the competing alternative of direct injection of landfill-derived gas into the natural gas system is less expensive than on-site generation of electric power.

[10] http://www.epa.gov/lmop/proj/index.htm

**Table I-7: Derivation of estimated undeveloped landfill gas energy recovery potential**

| | Waste in-place (tons) | Gas Generation Potential (MMscf/yr) | Fuel Energy (TBtu/yr) | Electric Energy (MWh/yr) | Developable Potential (MWa) |
|---|---|---|---|---|---|
| **Idaho** | 2,000,000 | 400 | 0.18 | 17893 | 2 |
| **Montana** | 16,956,766 | 3391 | 1.53 | 151701 | 17 |
| **Oregon** | 25,022,845 | 5005 | 2.25 | 223862 | 26 |
| **Washington** | 23,656,412 | 4731 | 2.13 | 211638 | 24 |
| **Totals** | **67636023** | **13527** | **6.09** | **605094** | **69** |

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from landfill gas energy recovery power plants is shown in Table I-8. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

**Table I-8: Levelized Cost of Landfill Gas Energy Recovery Power Plants**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $69.55 | $0.97 | $3.63 | $0.00 | $74 |
| 2015 | $68.53 | $0.99 | $3.65 | $0.00 | $73 |
| 2020 | $67.87 | $0.99 | $3.64 | $0.00 | $73 |
| 2025 | $67.22 | $0.99 | $3.63 | $0.00 | $72 |
| 2030 | $66.72 | $1.00 | $3.64 | $0.00 | $71 |

## *Animal Manure Energy Recovery*

The energy value of certain agricultural and food wastes can be recovered by processing the waste materials in anaerobic digesters. This yields a combustible gas that can be used to fuel a thermal electric power generator. Reciprocating engine-generator sets are typically used for the power production. The most widely employed anaerobic digestion technology at present, uses animal manure in liquid or slurry form. The principal source of suitable feedstock is from manure handling systems at large concentrated animal feeding operations (CAFOs).

***Reference Plant:*** The reference plant consists of a plug flow anaerobic digester supplied by liquid or slurry manure handling system at a large (500 head, or larger) CAFO dairy. The digester produces a low-Btu methane rich-gas that supplies an 850 kW reciprocating engine generating unit. Reject heat is recovered from the engine to maintain digester operating temperatures.

***Fuel:*** The animal waste is supplied from an adjacent concentrated animal feeding operation. Anaerobic digesters and associated power generation equipment provide a solution to the problem of disposing of large quantities of animal waste from large concentrated feeding operations. The value of the raw manure/fuel is assumed to be zero for this analysis. In some cases the raw manure might be considered to have a negative value.

***Heat rate:*** The heat rate of the reference plant is 10,250 Btu/kWh, derived as described for Landfill Gas Energy Recovery plants

***Availability parameters:*** Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

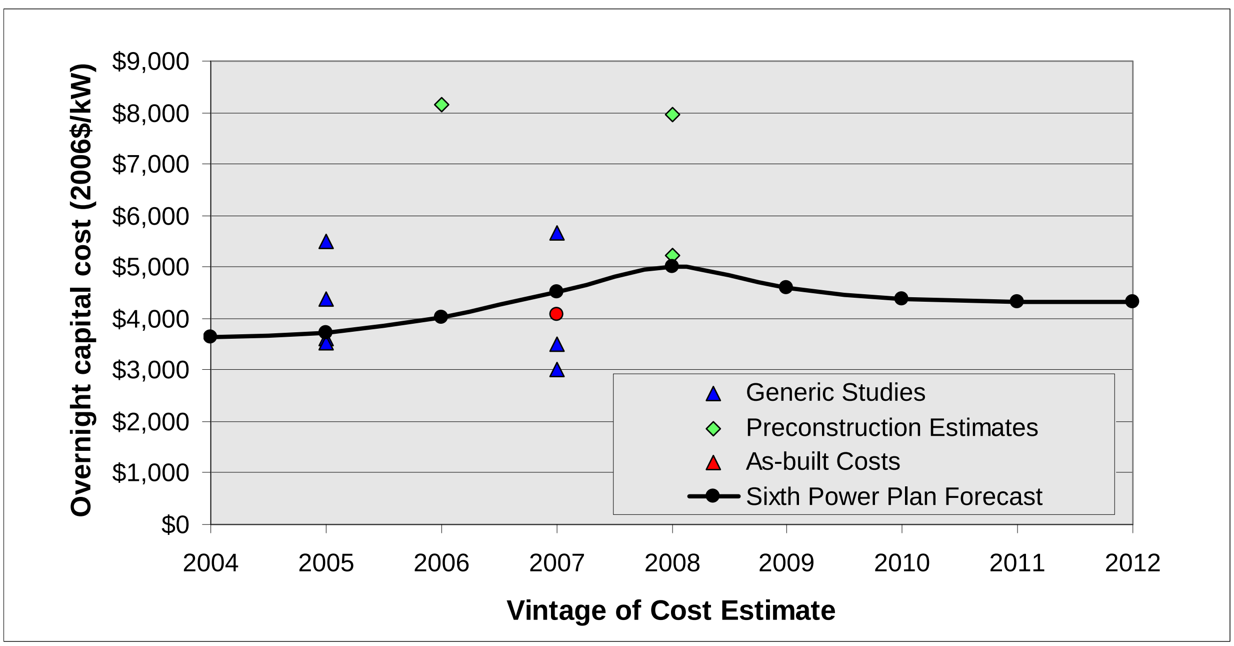
Equivalent annual availability - 88%

***Unit Commitment Parameters*****:** Animal waste energy recovery plants operate as must-run units at an annual capacity factor of 75%, based on CEC (2007).

***Total Plant Cost:*** The overnight total plant cost of the reference plant is $5000/kW installed capacity (2008 price year). This estimate is based on reported costs for one completed and three proposed plants and generic estimates from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs and a second source included estimates for a range of plant sizes. These observations were normalized as described in the Capital Cost Analysis subsection of this appendix, and are plotted by vintage in Figure I-5. If the one 2006 outlier is omitted, the distribution, though based on a limited sample size, is reasonably satisfying, with a wide range. The wide range is likely attributable site-specific factors including a wide capacity range and the increased cost of manure handling facilities for plants serving several farms, compared to on-farm plants. Costs rise rapidly as plant capacity declines. A range of $4,500/kW for larger units (1 - 3 MW) to $8,000 for smaller units (400 - 500kW) is consistent with $5,000/kW for the reference 850 kW unit. The Sixth Plan forecast shown in the figure is consistent with the general increase in power plant costs observed from 2004 through 2008, the 2005 generic estimates (ETO, 2005) and the reported cost of the one completed plant from the sample (Bettencourt Dry Creek Dairy in Idaho).

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

**Figure I-5: Published and forecast capital costs of animal manure energy recovery plants**



***Development and Construction Schedule, Cash Flows:*** Development and construction schedule and cash flow assumptions for an animal waste energy recovery plant are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, engineering) - 12 mo., 2% of total plant cost
>
> **Construction** (Major equipment order, site preparation, delivery of major equipment, completion of construction and testing) - 12 mo., 98% of total plant cost

***Operating and Maintenance Cost:*** Fixed O&M cost for animal waste energy recovery is taken as 0.9% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $72/kW/yr for small (450 kW) facilities, $45/kW/yr for mid-range (850 kW) facilities and $41/kW/yr for large (2.5 MW) facilities. Fixed O&M cost assumed to vary in real terms with total plant cost.

Variable O&M cost for animal waste energy recovery is taken as 0.3% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $24/MWh for small facilities, $15/kW/yr for mid-range facilities and $14/kW/yr for large facilities. Variable O&M cost is assumed to remain constant in real terms.

***Economic Life:*** The economic life of an animal waste energy recovery plant is assumed to be 15 years.

***Development potential:*** The remaining feasible development potential for animal manure energy recovery facilities at dairy operations in the Northwest is estimated to be 61 MWa with a possible range of 51 to 108 MWa. The derivation of this estimate is shown in Table I-9. Potentially feasible operations and mature head are reported by EPA for the top ten states, including Idaho and Washington. These are operations of 500 head, or more and employing slurry or liquid manure handling systems. The Oregon data are from ETO, 2005, and are based on dairy farms of 500 head or more. The Oregon estimates do not appear to have been screened for use of slurry of liquid manure handling systems, so may be high. The expected energy production potential was estimated from head count using the 3 kWh per mature head per day, described as "realistic" in (ETO, 2005). The low end of the range is based on the value of 2.6 kWh/head-day assumed in EPA[11] and the high end was based on "optimistic" 5 kWh/head-day of ETO (2005).

[11] 38.5 $ft^3$ methane per cow-day using plug flow digesters (EPA, p.31) x 66 kWh/1000 $ft^3$ methane (EPA, p.32).

**Table I-9: Derivation of estimated undeveloped animal manure energy recovery potential**

| | Feasible Operations | Mature Head at Feasible Operations (000) | Electric Generation Potential (MWa) | Operating and Committed Generation (MWa) | Developable Potential (MWa) |
|---|---|---|---|---|---|
| **Idaho**[12] | 185 | 285 | 36 | 7.9 | 29 |
| **Montana**[13] | -- | -- | -- | -- | -- |
| **Oregon**[14] | 32 | 114 | 14 | 0.5 | 14 |
| **Washington**[12] | 122 | 135 | 17 | 2.9 | 14 |
| **Totals** | **339** | **534** | **67** | **11.3** | **57** |

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from animal waste energy recovery power plants is shown in Table I-10. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

**Table I-10: Levelized Cost of Animal Waste Energy Recovery Power Plants**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $93.85 | $0.97 | $4.40 | $0.00 | $99 |
| 2015 | $82.83 | $0.99 | $4.24 | $0.00 | $88 |
| 2020 | $81.18 | $0.99 | $4.21 | $0.00 | $86 |
| 2025 | $79.57 | $0.99 | $4.18 | $0.00 | $85 |
| 2030 | $78.04 | $1.00 | $4.17 | $0.00 | $83 |

## *Waste Water Treatment Energy Recovery*

Sludge collected in the clarification stage of waste water treatment is commonly processed in anaerobic digesters to remove volatile organic materials. Anaerobic digestion produces a low-Btu gas consisting largely of methane and carbon dioxide. This gas can be treated to remove moisture, siloxanes, hydrogen sulfide, and other impurities and used to fuel an electric generating plant. Reject heat from the engine is used to maintain optimum digester temperature.

***Reference Plant:*** The reference plant is an 850-kilowatt reciprocating engine generating unit fuelled by gas from the anaerobic digestors of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperature. The plant includes gas processing equipment, the engine-generator, heat recovery equipment, interconnection equipment and associated infrastructure. The anaerobic digestors are assumed to be existing.

***Fuel:*** The fuel of the reference plant is supplied from a wastewater treatment facility with existing anaerobic sludge digesters and associated gas collection system (for flaring). The facilities are assumed to be under common ownership and the raw fuel supplied free of charge.

[12] U.S. Environmental Protection Agency (Undated)
[13] No estimates were located for Montana. The number of large confined dairy operations in Montana is thught to be small.
[14] Energy Trust of Oregon (2005)

***Heat rate:*** The heat rate of the reference plant is 10,250 Btu/kWh, derived as described for Landfill Gas Energy Recovery plants

***Availability parameters:*** Plant availability parameters are as follows:

Scheduled maintenance outages - 7 days/yr

Equivalent forced outage rate - 4.7%

Mean time to repair - Not estimated (stochastic outages not modeled)

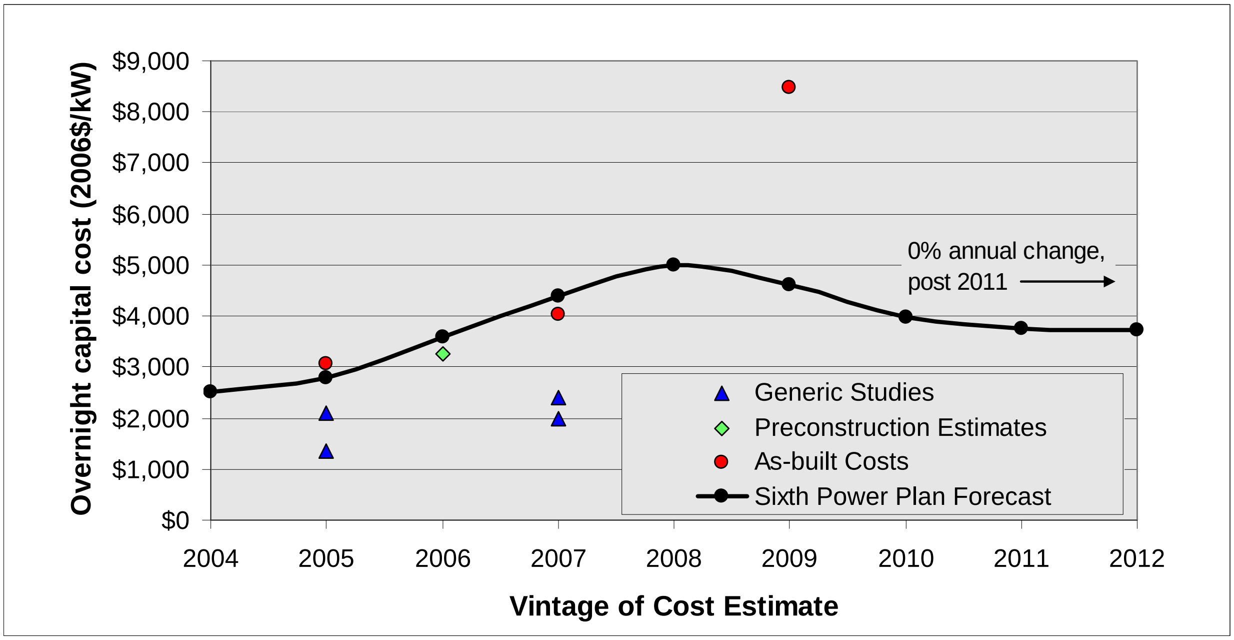
Equivalent annual availability - 93%

***Unit Commitment Parameters*****:** Wastewater treatment energy recovery systems operate as must-run units at an annual capacity factor of 85%, based on CEC (2007).

***Total Plant Cost:*** The "overnight" total plant cost of the reference plant is $5,000/kW installed capacity (2008 price year). This estimate is based on reported costs for one proposed and two completed plants (both a preconstruction and an as-built estimate is available for one of the latter). Generic estimates were obtained from three sources, one consisting of low and high bound costs. These observations were normalized as described in the Capital Cost Estimates section of this appendix, and are plotted by vintage in Figure I-6. The preconstruction and as-built costs are much higher than the generic estimates and show much stronger escalation in the 2004 - 08 period than do the generic costs. Because the underlying cost and plant configuration information for the 2005, 2006, and 2007 as-built and preconstruction estimates is reliable and representative, these strongly influenced the Sixth Power Plan estimate. The scope of the 2009 outlier is believed to be more extensive than a typical project, hence the much higher cost.

Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

**Figure I-6: Published and forecast capital costs of waste water treatment energy recovery plants**




***Development and Construction Schedule, Cash Flows:*** Development and construction schedule and cash flow assumptions are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 8% of total plant cost.
>
> **Construction** (Final engineering, major equipment order, site preparation, delivery of major equipment, completion of construction and testing) - 12 mo., 92% of total plant cost.

***Operating and Maintenance Cost:*** Fixed O&M cost, exclusive of property tax and insurance for wastewater treatment plant energy recovery ($40/kW/yr) is taken as 0.8% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007). Variable O&M ($30/MWh) is taken as 0.6% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007). Fixed O&M costs is assumed to vary in real terms with total plant cost. Variable O&M costs are assumed to remain constant in real terms.

***Economic Life:*** The economic life of a wastewater treatment energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator.

***Development potential:*** The remaining feasible development potential for wastewater treatment energy recovery facilities in the Northwest is estimated to be about 12 MWa. This estimate is based on a 2007 inventory of wastewater treatment plant energy recovery potential prepared by the U.S. Environmental Protection Agency (EPA, 2007), adjusted for existing development.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from waste water treatment energy recovery power plants is shown in Table I-11. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

**Table I-11: Levelized Cost of Waste Water Treatment Energy Recovery Power Plants**

| Service Year | Plant Busbar ($/MWh) | Integration ($/MWh) | Transmission And Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $100.72 | $0.97 | $4.40 | $0.00 | $106 |
| 2015 | $91.56 | $0.99 | $4.10 | $0.00 | $97 |
| 2020 | $90.08 | $0.99 | $4.07 | $0.00 | $95 |
| 2025 | $88.64 | $0.99 | $4.05 | $0.00 | $94 |
| 2030 | $87.33 | $1.00 | $4.04 | $0.00 | $92 |

## *Woody Residue Power Plants*

Woody residue includes mill residues, logging slash, urban construction and demolition debris, urban forest and landscaping debris, unmerchantable products of commercial forest management and ecosystem restoration and woody energy crops. Conventional steam-electric plants with or without CHP will be the chief technology for electricity generation using woody residue in the near-term. Modular biogasification plants are under development and may be introduced within the next several years. Modular units would open the possibility of “bringing the plant to the fuel” thereby expanding the potential fuel supply, reducing fuel transportation costs and improving the economics of plant operation.

***Reference Plants:*** Two cases were modeled. A “Brownfield” case is sited to provide a cogeneration load, at a brownfield site with existing transportation, water, and transmission infrastructure. Locally available mill residue and other residue fuels are assumed sufficient to supply the plant’s fuel requirements. Refurbished salvaged equipment is available for the steam turbine-generator and other major equipment. This plant represents a favorable situation for development of new generating capacity using wood residues. The second, “Greenfield” case is a plant using new equipment, at a greenfield site and no cogeneration load. The plant is developed primarily to operate on woody residue from commercial forest thinning, harvest, and forest ecological restoration projects. This plant represents the longer-term marginal cost of expanding generation from woody residues. A third option based on smaller-scale, highly modular technology that could be periodically relocated to minimize fuel transportation costs and interconnect to local distribution lines is not commercially available, but may be introduced within the next several years. This concept could lower the marginal cost of expanding electricity generation from forest residue fuels.

The reference Brownfield plant is a 15 MW (gross), 13.2 MW (net) steam-electric plant with travelling grate furnace and extraction/condensing steam turbine-generator. 28.000 lb/hr of 150 psig steam is extracted for thermal applications. The plant is provided with mechanical draft condenser cooling. Overfire air, cyclones and precipitators are used for air emission control. Reconditioned equipment is used where feasible. The fuel supply largely consists of mill, logging and urban wood residues within a 50 to 75 mile radius, augmented by forest thinning and restoration residues.

The reference Greenfield plant is a 25 MW (nominal) fluidized bed steam-electric plant with a full condensing steam turbine-generator. The plant is provided with mechanical draft condenser cooling. Selective non-catalytic NOx reduction, cyclones and fabric filters are employed for air emission control. The plant consists largely of new equipment. The fuel supply largely consists of forest thinning and restoration residues within a 50 to 75 mile radius, augmented by mill, logging and urban wood residues.

***Fuel:*** The fuel supply consists of various proportions of mill residues, logging slash and forest thinning residues. The delivered cost of these is assumed to be as follows:

Mill residues - $1.33/MMBtu

Logging slash - $3.00/MMBtu

Forest thinning - $3.30/MMBtu

The fuel supply of the Brownfield plant largely consists of mill, logging and urban wood residues, augmented by forest thinning residues with a net cost of $1.60/MMBtu. The fuel supply of the Greenfield plant largely consists of forest thinning residues, supplemented with limited quantities of mill residue and logging slash with a net cost of $3.00/MMBtu, declining at 1% (real) per year from improvements in fuel bundling and transportation equipment.

***Heat rate:*** The overall heat rate of the reference CHP plant is 19,300 Btu/kWh. The heat rate of the stand-alone plant is 15,500 Btu/kWh.

***Availability Parameters:*** Plant availability parameters are as follows:

Scheduled maintenance outages - 28 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 56 hours

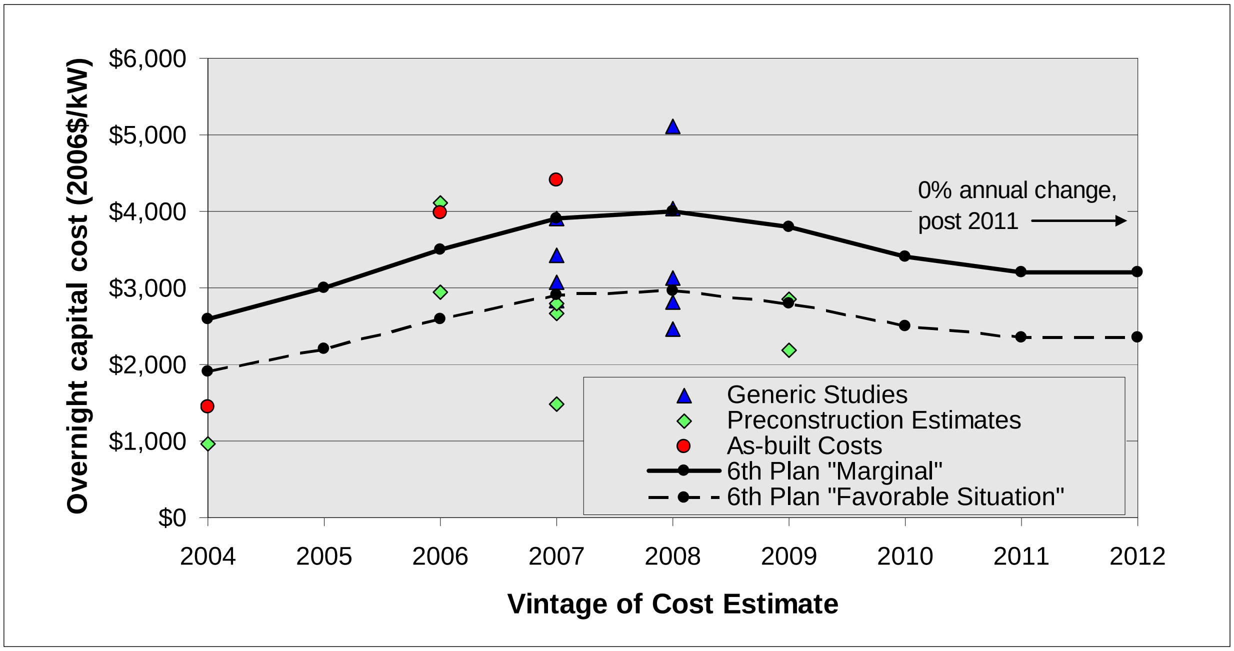
Equivalent annual availability - 86%

***Unit Commitment Parameters*:** Woody residue steam-electric plants are assumed to operate as must-run units at an annual capacity factor of 80%.

***Total Plant Cost:*** The typical total plant cost of a plant developed under Brownfield conditions is estimated to be $3000/kW (net) capacity (2008 price year). The Greenfield plant representing longer-term marginal development conditions is estimated to cost $4,000/kW (net) installed capacity (2008 price year). These estimates were derived from six generic cost reports; preconstruction cost estimates from eight projects and as-built costs for three projects. The normalized cost estimates and resulting assumptions for the Sixth Power Plan are illustrated in Figure I-7. The Greenfield plant was used in the portfolio risk studies. The low-bound cost of -50% ($2000) represents the addition of a pressure drop steam turbine-generator to an existing industrial process steam system. The high bound cost of +25% ($5,000) represents greenfield construction of a new small plant.

Construction costs are forecast to decline by 5% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

**Figure I-7: Published and forecast capital costs of woody residue power plants**




***Development and Construction Schedule, Cash Flows:*** Development and construction schedule and cash flow assumptions are as follows:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 2% of total plant cost
>
> **Early Construction** (Final engineering, major equipment order, site preparation) - 12 mo., 45% of total plant cost
>
> **Committed Construction** (Delivery of major equipment, completion of construction and testing) - 12 mo., 53% of total plant cost.

***Operating and maintenance costs:*** The estimated operating and maintenance costs for the reference Brownfield plant with CHP are $194/kW/yr fixed and $0.73/MWh variable. These costs are from Port of Port Angeles (2009), adjusted to the mid-2008 price point and 2006 dollars used for this plan. The estimated operating and maintenance costs for the reference Greenfield plant are $180/kW/yr fixed and $3.70/MWh variable. These are based on CEC (2007), adjusted to the mid-2008 price point and 2006 dollars used for this plan. Fixed O&M costs are forecast to decline to equilibrium values, and then stabilize as described for construction costs. Variable O&M costs are assumed to remain constant in real terms.

***Value of steam sales:*** Extracted 150 psi saturated steam is assumed to be values at $5.00/1000 lbs, based on Port of Port Angeles (2009).

***Economic Life:*** Assumed to be 20 years. Though a new steam-electric plant can operate for 30 years, or more, the expected economic life of a steam-electric plant fuelled by woody residue and with cogeneration load is limited by uncertainties regarding continued fuel supply availability and the viability of the host facility.

***Development potential:*** The estimated remaining regional development potential is 830 MW of capacity yielding 665 MWa of energy. This is based on estimates of woody residue supply developed for the Western Governor's Association (WGA, 2006). The derivation of the capacity and energy potential from the base WGA estimates of residue availability are shown in Table I-12.

**Table I-12: Derivation of estimated undeveloped woody residue energy potential**

| | Forestry (MMODT) | MSW Biogenic (MMODT) | Total (MMODT) | Total (TButu/yr)[15] | Practical Potential (TBtu/yr)[16] | Energy[17] (aMW) | Capacity[18] (MW) |
|---|---|---|---|---|---|---|---|
| Idaho | 2.05 | 0.43 | 2.47 | 43.0 | 17.2 | 127 | 158 |
| Montana | 1.83 | 0.50 | 2.33 | 40.6 | 16.2 | 119 | 149 |
| Oregon | 1.51 | 1.65 | 3.16 | 55.0 | 22.0 | 162 | 203 |
| Washington | 1.54 | 3.47 | 5.01 | 87.2 | 34.9 | 257 | 321 |
| **Total** | | | | | | **665** | **831** |

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from two woody residue power plants cases is shown in Table I-13. The Brownfield case represents a best case situation. This case assumes the use of refurbished plant equipment, a brownfield site with existing transportation, water, wastewater and transmission infrastructure, a local supply of mill residue, urban wood residues or other low-cost fuel, and revenue from a cogeneration load. The Greenfield case represents the marginal cost of new woody residue power plants. This case assumes the use of new (though more efficient) plant equipment, a greenfield site, forest residue supplied from remote logging, pre-commercial thinning or ecological restoration operations, and no cogeneration load. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

**Table I-13: Levelized Cost of Woody Residue Power Plants**

| Case | Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| **Brownfield** | 2010 | $92.06 | $0.97 | $4.21 | $0.00 | $97 |
| | 2015 | $83.30 | $0.99 | $4.08 | $0.00 | $88 |
| | 2020 | $83.35 | $0.99 | $4.09 | $0.00 | $88 |
| | 2025 | $83.43 | $0.99 | $4.09 | $0.00 | $89 |
| | 2030 | $83.63 | $1.00 | $4.11 | $0.00 | $89 |
| **Greenfield** | 2010 | $132.70 | $0.97 | $4.99 | $0.00 | $139 |
| | 2015 | $118.83 | $0.99 | $4.77 | $0.00 | $125 |
| | 2020 | $117.46 | $0.99 | $4.75 | $0.00 | $123 |
| | 2025 | $116.66 | $0.99 | $4.74 | $0.00 | $122 |
| | 2030 | $116.64 | $1.00 | $4.75 | $0.00 | $122 |

[15] Assumed average heat value of 17.4 MM Btu per oven dry ton.
[16] Assumed excess fuel supply ratio of 2.5 to ensure reliable long-term fuel supply.
[17] Assumed heat rate of 15,500 Btu/kWh.
[18] Assumed annual average plant capacity factor of 80%.

## *Geothermal*

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest.  A preference for binary-cycle or heat-pump technology is emerging because of modularity, applicability to lower temperature geothermal resources, and the environmental advantages of a closed geothermal-fluid cycle.  In binary plants, the geothermal fluid is brought to the surface using wells, and passed through a heat exchanger where the energy is transferred to a low boiling point fluid.  The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger.  The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as a baseload resource.  Flashed steam plants typically release a small amount of naturally occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide.

***Reference Plant:*** The reference plant is a 40 megawatt (nominal) binary cycle plant comprised of three 13-megawatt (net) units.  The plant is assumed to use closed loop organic Rankine cycle technology suitable for low geothermal fluid temperatures.  The plant includes production and injection wells, geothermal fluid piping, power block, cooling towers, step-up transformers, switchgear and interconnection facilities, and security, control, and maintenance facilities.  Wet cooling, resulting in higher plant efficiency, greater productivity, and lower cost, would likely be used at sites with sufficient water.  Dry cooling could be employed at sites with insufficient cooling water availability, at additional cost and some sacrifice in efficiency and productivity.

***Availability Parameters:*** Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 6.4%

Mean time to repair - 40 hours

Equivalent annual availability - 90%

***Unit Commitment Parameters*****:** Geothermal plants are assumed to operate as must-run units.

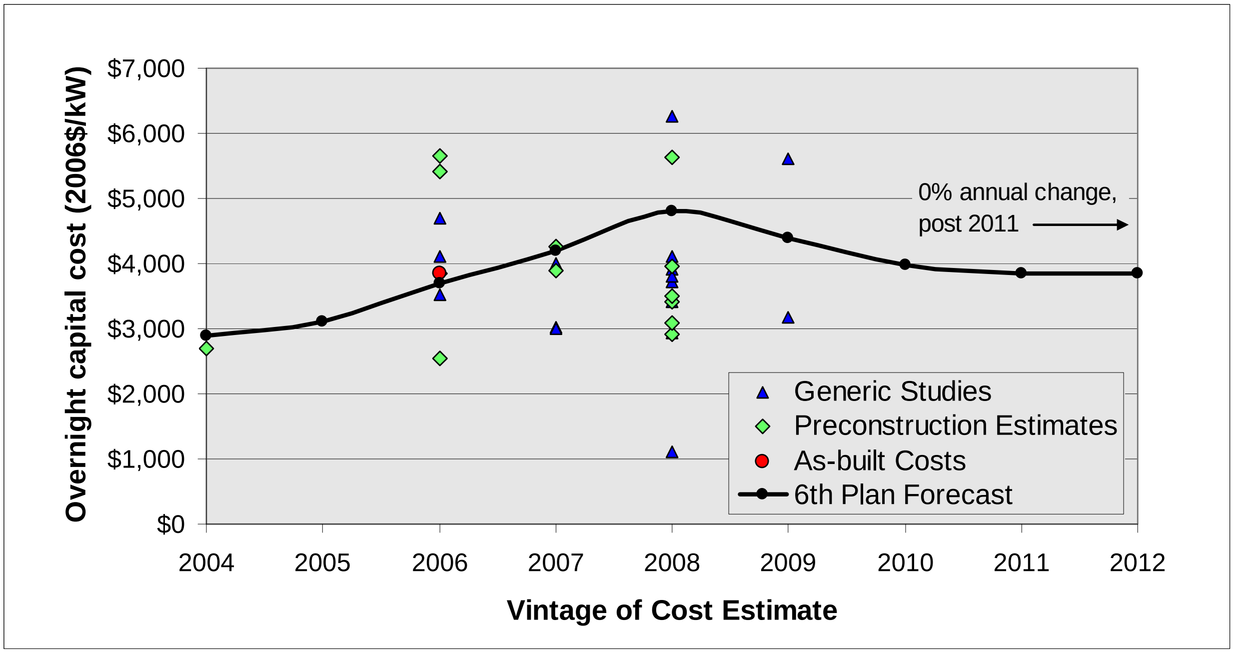
***Capacity Factor:*** The average capacity factor over the life of the facility is assumed to be 90%.

***Heat Rate:*** The average annual full load heat rate is 28,500 Btu/kWh, typical of an ORC binary plant operating on 300$^{o}$F geothermal fluid.

***Total Plant Cost:*** The total plant cost of the reference geothermal plant is $4,800/kW installed capacity (2008 price year).  This estimate is based on a sample of one reported as-built plant cost and 12 preconstruction estimates, including one estimate consisting of low and high bound costs. Ten generic estimates of geothermal plant development costs were also obtained.  Five of these were range estimates consisting of low and high bound costs and one included low, mid-range, and high bound costs.  Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-8.  A wide range of costs is evident and the general increase in power plant construction costs from 2004 through mid-2008 is poorly defined.  The reference plant cost estimate of $4800/kW is based on a rough projection of average cost trends from 2004 through 2007 and lies on the high side of the 2008 cluster. The 2008 base year forecast does relate reasonably well to the 2009 generic estimates (the 2009 estimates are a range estimate representing a low-temperature deep resource (high cost) and a higher temperature shallower resource (low cost). A cost uncertainty of -33% ($3,200) to +17% ($5,600), for the portfolio model risk analysis, is based on the range of 2008 vintage costs, excluding the two extreme outlying values.

Total plant costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Total plant costs are assumed to remain constant in real terms thereafter.

**Figure I-8: Published and forecast capital costs of geothermal power plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

**Development** (Site option to completion of exploration) - 36 mo., 10% of total plant cost

**Early Construction** (Wellfield confirmation and development) - 12 mo., 35% of total plant cost

**Committed Construction** (Power plant, pipelines and infrastructure) - 24 mo., 55% of total plant cost

***Operating and Maintenance Cost:*** Estimated operating and maintenance costs for the reference plant are $175/kW/yr fixed plus $4.50/MWh variable. This estimate is derived from eight published sources containing estimates of geothermal plant operating and maintenance costs. Each source is associated with a capital cost estimate, allowing O&M costs to be estimated in terms of percentage of capital cost, a common approach. The O&M cost estimates were first adjusted to 2006 dollar values. Some estimates include both fixed and variable components, some are fixed only, and others are in fully variable terms. Variable costs were converted to equivalent fixed values, assuming a 90% capacity factor. These were added to the fixed O&M component, if any, yielding total O&M cost in fixed terms, in 2006 year dollars. The resulting values were converted to percentages of total plant cost based on the associated normalized capital costs. This yielded an average value of 5% (omitting one extreme value associated with an unrepresentative low capital cost); $210/kW/yr using the capital cost of the reference plant. Fixed and variable components were derived from this estimate by assuming the variable component to be $4.50/MWh (the value from CEC, 2007). Deducting the fixed equivalent of $4.50/MWh at 90% capacity factor from $210/kW/yr yields the $175/kW/yr fixed component. Fixed O&M costs is assumed to vary in real terms with total plant cost. Variable O&M costs are assumed to remain constant in real terms.

***Economic Life:*** The economic life of a geothermal plant is assumed to be 30 years; limited by wellfield viability and equipment life.

***Development Potential:*** A recent U.S. Geological Survey assessment of moderate and high temperature hydrothermal resources[19] yielded a mean total electricity generating potential with 95% confidence of 266 MWe[20] of from currently identified resources and 1,103 MWe from currently undiscovered resources within the four Northwest states for a total of 1,369 aMW of energy potentially available with high confidence. However, factors including the limited development in the Northwest to date, the high frequency of dry holes encountered during earlier attempts to develop Northwest geothermal projects, siting resistance encountered in earlier efforts to develop Northwest geothermal resources, the high risk and long lead time associated with the confirmation of geothermal resources, and the relatively few sites currently under development all suggest that the Northwest resource potential during the period of this plan will be limited by development rate rather than ultimate availability. Based on geothermal development experience in Nevada, a state with similar types of geothermal resources as the Northwest, we assume that resources can be developed at a maximum rate of 14 MW per year in from 2011 through 2014, increasing to 24 MW per year, on average for the duration of the planning period. This would yield a maximum of 416 megawatts of hydrothermal resource over the term of the plan. At 90 percent capacity factor, this capacity would yield 374 average megawatts of energy. These assumptions are believed to be conservative and should be revisited at the biennial assessment of the Sixth Power Plan when it is expected that additional Northwest geothermal development experience will be available.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from geothermal power plants is shown in Table I-14. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

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[19] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.
[20] In this study, one MWe is defined as the capability of generating 8.77 GWh (one average megawatt) continuously for a period of 30 years.

**Table I-14: Levelized Cost of Geothermal Power Plants**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $83.93 | $0.98 | $3.79 | $0.00 | $89 |
| 2015 | $76.22 | $0.99 | $3.68 | $0.00 | $81 |
| 2020 | $76.10 | $1.00 | $3.69 | $0.00 | $81 |
| 2025 | $76.17 | $1.00 | $3.70 | $0.00 | $81 |
| 2030 | $76.22 | $1.01 | $3.71 | $0.00 | $80 |

## *Hydropower*

The theoretical hydropower potential of the Northwest has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible sites have been developed and the remaining opportunities are a diversity of small-scale projects. These include equipment upgrades and capacity expansion at existing projects, projects on irrigation canal and conduit drops and high-head diversions on small headwater streams. As the technology improves and costs reduced, hydrokinetic turbines may see increased applications.

***Reference Plant:*** Because of the diversity of remaining hydropower development opportunities, no single plant configuration is representative of the remaining development opportunities. Cost and performance assumptions were based on the characteristics of recently developed proposed hydropower plants in the WECC. For modeling purposes, the capacity of a typical new unit is assumed to be 10 MW.

***Availability Parameters:*** Not evaluated. New hydropower plants are assumed to operate at the average capacity factor described below.

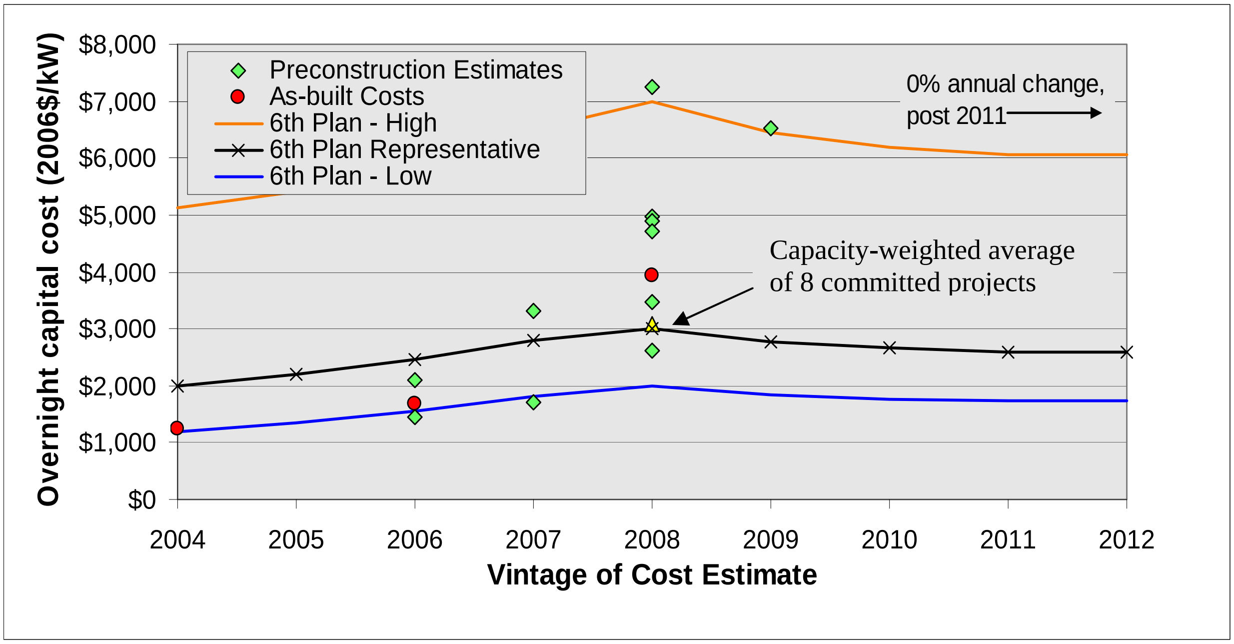
***Unit Commitment Parameters*:** Hydropower plants are assumed to operate as must-run units.

***Capacity Factor:*** The average capacity factor over the life of the facility is assumed to be 50%. This is based on the average of the reported energy production of a sample of 15 recently developed and proposed hydropower plants in the WECC (49.4%), rounded to 50%.

***Total Plant Cost:*** Cost information was located for 14 proposed and recently-constructed hydropower projects in the WECC region. No generic hydropower cost information was located. The costs of the 14 projects, normalized to overnight 2006 dollar values, are plotted by vintage in Figure I-9 (both preconstruction estimates and as-built costs were available for two of the projects). Partially because of the relatively little hydropower development in earlier years and a recent acceleration of development proposals, perhaps due to state renewable portfolio standards and similar BC energy policy, most of the costs are dated from 2008. An accelerating increase in project cost through 2008, similar to that observed for other generating technologies is evident. Also evident is a very wide spread of cost, particularly for 2008, likely due to wide variation in project configuration, size, and project scope. The latter ranges from rehabilitation of retired projects, through addition of power generation to existing water control structures to full new project construction.

The representative 2008 cost of $3,000/kW is the rounded capacity-weighted, escalation-adjusted average cost of eight "committed" (recently completed or under construction) projects. The low bound cost ($2,000/kW in 2008) was set so its historical curve includes the as-built costs of low-cost completed projects (Figure I-9). The high bound cost ($7,000/kW in 2008) includes all projects except for two outliers (one off the chart of Figure I-9). Much of the capital cost of the two outlying projects is associated with converting existing open irrigation ditches to piping for non-hydropower purposes of (controlling water loss).

**Figure I-9: Published and forecast capital costs of new hydropower projects**




Construction costs are forecast to decline by 8% (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for a typical small hydropower plant are as follows:

> **Development** (Issuance of preliminary permit to receipt of FERC license and selection of EPC contractor) - 48 mo., 12% of total plant cost
>
> **Construction** (Site preparation, construction and commissioning) - 24 mo., 88% of total plant cost

***Operating and Maintenance Cost:*** Operating and maintenance costs are assumed to be 3% of overnight capital cost. This assumption yields $90/kW/yr for the representative case, $60/kW/yr for the low bound case and $210/kW/yr for the high bound case. The variable component is small and is included in the fixed O&M estimate. O&M cost is assumed to vary in real terms with total plant cost.

***Economic Life:*** The economic life of a small hydropower plant is assumed to be 30 years; limited by major equipment life.

***Development Potential:*** A comprehensive assessment of new hydropower potential has not been attempted by the Council since the Fourth Power Plan. In that plan, the Council estimated that about 480 megawatts of additional hydropower capacity was available for development at costs of 9.0 cents per kilowatt-hour or less. This capacity could produce about 200 megawatts of energy on average. Few projects have been developed in the intervening years, and it is likely that the Fourth Power Plan estimate remains representative. Because of increasing interest in the acquisition of renewable resources and expanding the diversity of renewable resource acquisitions, Bonneville and the Council are undertaking a new assessment of undeveloped hydropower potential.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from the two new hydropower cases is shown in Table I-15. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal production tax credit.

**Table I-15: Levelized Cost of New Hydropower Plants**

| Case | Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| Favorable Site | 2010 | $57.81 | $0.98 | $5.00 | $0.00 | $64 |
| | 2015 | $54.30 | $0.99 | $5.00 | $0.00 | $60 |
| | 2020 | $54.27 | $1.00 | $5.02 | $0.00 | $60 |
| | 2025 | $54.31 | $1.00 | $5.04 | $0.00 | $60 |
| | 2030 | $54.33 | $1.01 | $5.05 | $0.00 | $60 |
| Typical Site | 2010 | $89.04 | $0.98 | $5.60 | $0.00 | $96 |
| | 2015 | $81.45 | $0.99 | $5.53 | $0.00 | $88 |
| | 2020 | $81.41 | $1.00 | $5.55 | $0.00 | $88 |
| | 2025 | $81.47 | $1.00 | $5.56 | $0.00 | $88 |
| | 2030 | $81.50 | $1.01 | $5.58 | $0.00 | $88 |

## *Utility-scale Solar Photovoltaic Plants*

Though photovoltaics have been widely employed for many years to supply power to small remote loads, larger-scale and grid-connected photovoltaic installations have been few in number and capacity because of the high cost of the technology and low productivity relative to alternatives. Over the past several years, strong public and political support has lead to attractive financial incentives and multi-megawatt grid-connected installations are becoming increasingly common.

A wide variety of photovoltaic plant designs are possible with various combinations of cell, module, and mounting design. A basic tradeoff is energy conversion efficiency vs. cost. Thin-film photovoltaic cells mounted on fixed racks results in a (relatively) low cost, rugged design. Conversion efficiency is low, however, and thin-film cell output tends to deteriorate over time. Efficiency and durability can be increased by use of single-crystalline cells mounted on single axis tracking devices. The ultimate in efficiency can be achieved by use of concentrating lenses focused on multijunction cells sensitive to a wide spectral range, mounted on fully automatic dual axis trackers. But each increase in efficiency comes at a greater cost, and complexity. Moreover, the most efficient designs, those employing concentrating devices, operate only on direct solar radiation so are more suitable for Southwestern locations where clear skies prevail.

***Reference Plant:*** The reference plant is 20 megawatt (net ac output) plant using flat plate (non-concentrating) single crystalline modules mounted on single-axis trackers. The 25 MW dc module output is converted to alternating current for grid interconnection using solid-state inverters. Inverter, cabling and transformer losses result in a net output of 20 MW ac. The plant also includes step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. The deployment strategy would locate smaller individual plants at scattered locations within the better solar resource areas of the region. This should reduce instances of simultaneous ramping due to cloud movement, reduce environmental concerns and permitting issues, shorten lead time and reduce interconnection costs.

***Availability Parameters:*** Not evaluated. Solar photovoltaic plants are assumed to operate at the average capacity factors described below.

***Unit Commitment Parameters*:** Solar photovoltaic plants are assumed to operate as must-run units.

***Capacity Factors and Temporal Output:*** Annual capacity factor and seasonal daily and hourly output was estimated for five reference locations using the NREL Solar Advisor Model ((https://www.nrel.gov/analysis/sam/). Monthly average plant output and annual average capacity factors (ac rating to net ac output) are provided in Table I-16 and illustrated in Figure I-10. Example average hourly plant output for the Boise location is provided in Table I-17 and illustrated in Figure I-11.

The plant design assumptions used for this analysis are as follows:

Configuration - Flat plate, tracker-mounted, inverted to ac output, no storage

Array DC power - 25.3 MW (yielding nominal 20 MW ac output)

Modules - 12 x 10549 (126588) SunPower SPR-200-BLK(c-Si)

Mounting - Single-axis tracker

Inverters - (98) Xantrex GT250-480-POS

System degradation - 1%/yr, compounded

Internal derate factor - 84%, excluding inverter conversion efficiency

Overall performance ratio (dc rating > ac output) - 78%-79% (location-specific)

**Table I-16: Estimated monthly net energy production (MWh) and annual capacity factors for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers (ac rating to net ac output)**

| | Billings, MT | Boise, ID | Burns, OR | Ely, NV | Yakima, WA |
|---|---|---|---|---|---|
| Jan | 1722 | 1586 | 1722 | 2904 | 1255 |
| Feb | 2294 | 2244 | 2173 | 3083 | 1915 |
| Mar | 3566 | 3544 | 3323 | 4524 | 3391 |
| Apr | 3930 | 4404 | 4208 | 4914 | 3891 |
| May | 4977 | 5291 | 5180 | 5614 | 5245 |
| Jun | 5088 | 5656 | 5511 | 6121 | 5572 |
| Jul | 5837 | 6192 | 5859 | 6161 | 5941 |
| Aug | 5220 | 5637 | 5530 | 5461 | 5320 |
| Sep | 4059 | 4516 | 4421 | 5224 | 4258 |
| Oct | 2868 | 3389 | 3219 | 4086 | 2858 |
| Nov | 1905 | 1830 | 1540 | 2632 | 1279 |
| Dec | 1487 | 1421 | 1299 | 2579 | 1093 |
| Annual | 24.5% | 26.4% | 25.4% | 30.4% | 24.3% |

**Figure I-10: Estimated monthly net energy production for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers**

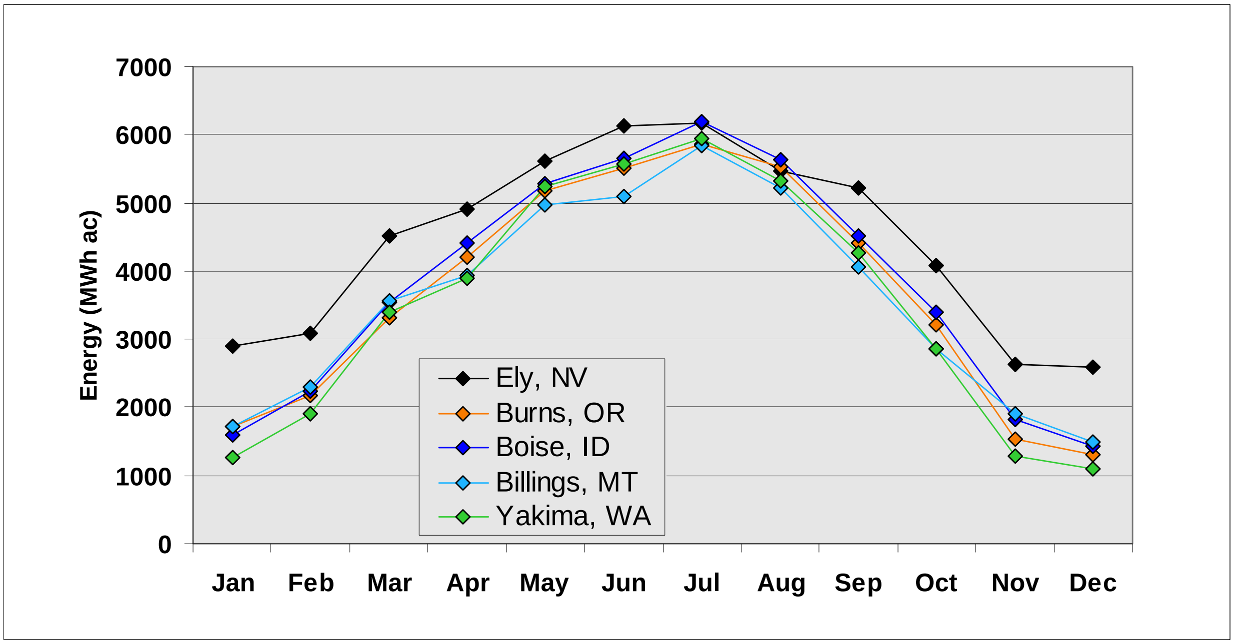
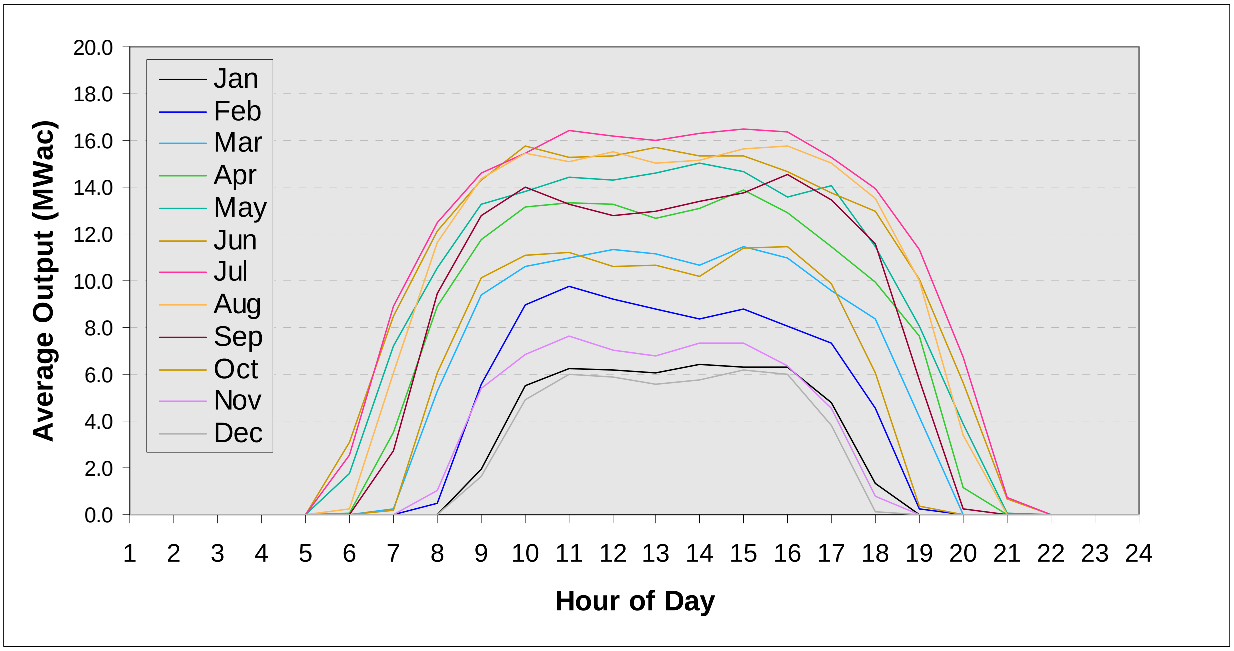



**Table I-17: Average hourly energy output by month (Boise example)**

| Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 6 | 0.00 | 0.00 | 0.00 | 0.08 | 1.78 | 3.10 | 2.54 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | 0.00 | 0.00 | 0.25 | 3.53 | 7.22 | 8.50 | 8.90 | 6.09 | 2.70 | 0.16 | 0.00 | 0.00 |
| 8 | 0.00 | 0.47 | 5.29 | 8.90 | 10.55 | 12.15 | 12.50 | 11.61 | 9.45 | 6.09 | 1.02 | 0.00 |
| 9 | 1.95 | 5.58 | 9.37 | 11.77 | 13.25 | 14.32 | 14.62 | 14.34 | 12.79 | 10.14 | 5.37 | 1.65 |
| 10 | 5.52 | 8.99 | 10.63 | 13.16 | 13.81 | 15.73 | 15.46 | 15.46 | 13.98 | 11.06 | 6.85 | 4.92 |
| 11 | 6.27 | 9.75 | 11.00 | 13.33 | 14.44 | 15.28 | 16.44 | 15.09 | 13.25 | 11.22 | 7.61 | 5.97 |
| 12 | 6.20 | 9.24 | 11.35 | 13.30 | 14.33 | 15.34 | 16.17 | 15.54 | 12.76 | 10.61 | 7.03 | 5.89 |
| 13 | 6.05 | 8.82 | 11.17 | 12.69 | 14.60 | 15.71 | 15.98 | 15.01 | 12.95 | 10.68 | 6.82 | 5.59 |
| 14 | 6.45 | 8.37 | 10.65 | 13.11 | 15.00 | 15.33 | 16.33 | 15.17 | 13.41 | 10.19 | 7.36 | 5.77 |
| 15 | 6.28 | 8.82 | 11.47 | 13.86 | 14.64 | 15.36 | 16.46 | 15.62 | 13.78 | 11.39 | 7.31 | 6.17 |
| 16 | 6.32 | 8.08 | 10.97 | 12.88 | 13.58 | 14.70 | 16.37 | 15.76 | 14.54 | 11.46 | 6.37 | 5.99 |
| 17 | 4.81 | 7.30 | 9.58 | 11.48 | 14.04 | 13.74 | 15.28 | 15.05 | 13.46 | 9.91 | 4.52 | 3.82 |
| 18 | 1.36 | 4.52 | 8.39 | 9.97 | 11.46 | 12.94 | 13.92 | 13.51 | 11.55 | 6.06 | 0.79 | 0.11 |
| 19 | 0.00 | 0.26 | 4.19 | 7.62 | 8.08 | 10.08 | 11.31 | 9.98 | 5.74 | 0.39 | 0.00 | 0.00 |
| 20 | 0.00 | 0.00 | 0.03 | 1.13 | 3.86 | 5.63 | 6.76 | 3.40 | 0.22 | 0.00 | 0.00 | 0.00 |
| 21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.66 | 0.74 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Figure I-11: Average hourly energy output by month (Boise location)**




***Unit Commitment Parameters*****:** Solar photovoltaic plants are assumed to operate as must-run units.

***Total Plant Cost:*** The total plant cost is estimated to be $9000/kW (2008 price year) on a nominal ac rating basis. Publically-available cost information was located for 7 proposed or recently-constructed solar photovoltaic plants, ranging in size from 5 to 46 MWdc. Four generic cost estimates for projects greater than one megawatt were also located. These costs, normalized as total plant cost in 2006 dollars per net ac kW of capacity are plotted by the vintage of the cost data in Figure I-12. Also plotted in Figure I-12 are retail module prices for 2005 through 2008 compiled by the Energy Trust of Oregon. Total plant costs through time should bear a close relationship to module costs. The Sixth Power Plan representative cost curve is based on the costs of actual projects, especially those using tracking crystalline modules and the shape of the historical module cost curve. Less weight was placed on the three low-lying generic examples. Partly this was because the rating basis (ac or dc) of these examples was not reported, and if dc (as is often the case), the costs would be about 20% greater than plotted. Secondly, these examples lie below the retail module prices reported by the Energy Trust of Oregon. It is unlikely that even the discount associated with bulk orders would lead to the total plant costs of these three generic cases.

As shown in Figure I-12, module costs declined in real terms in 2008 with increases in production capacity. Preliminary information indicates that this decline continued in 2009 as demand slackened. Continuing real dollar declines in module costs over the long-term are anticipated with improvements in cell efficiency, increased production automation and increases in production capacity. Reduction in module costs and increases in plant size should lead to continued reduction in total plant costs. The long-term forecast of solar photovoltaic plant costs used for this plan are based on forecasts prepared by Navigant for the state of Arizona (Navigant, 2007) and Black and Veatch for Idaho Power (Black & Veatch, 2008). These, and the forecast used for this plan are shown in Figure I-13.  Note that in contrast to Figure I-12, the horizontal axis of Figure I-13 is scaled to year of service for consistency with the Navigant and Black & Veatch forecasts.  The vertical axis scale should be considered relative since the Black & Veatch estimates are not defined as to ac or dc basis.

**Figure I-12: Published and forecast capital costs of utility-scale solar photovoltaic plants**

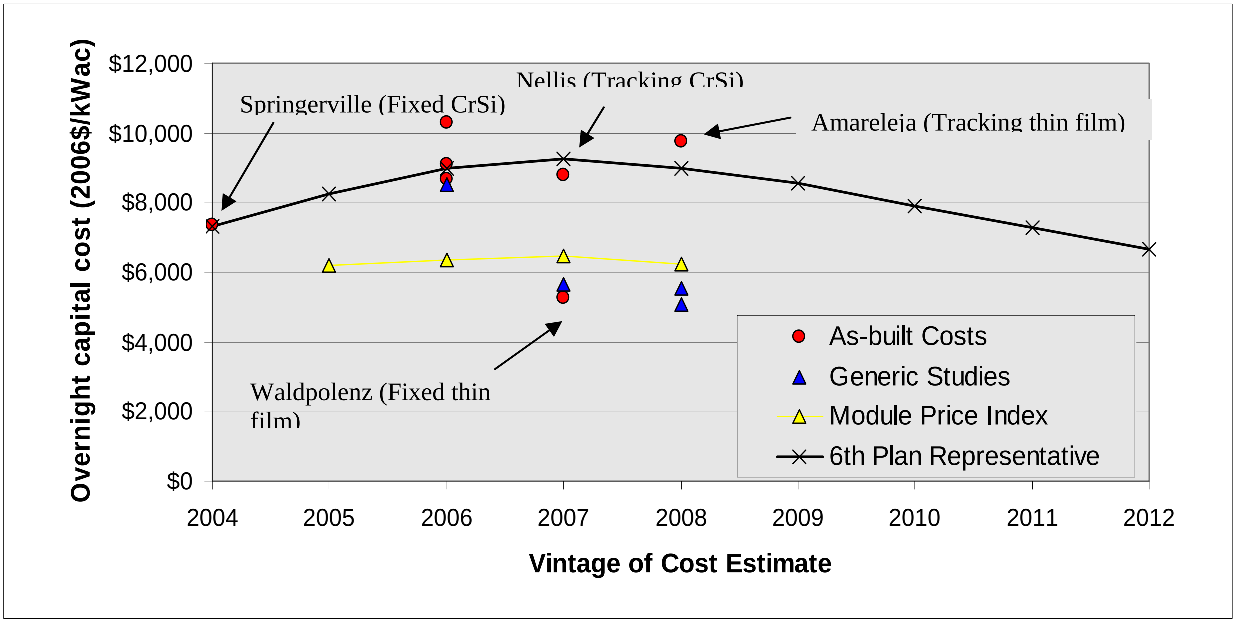
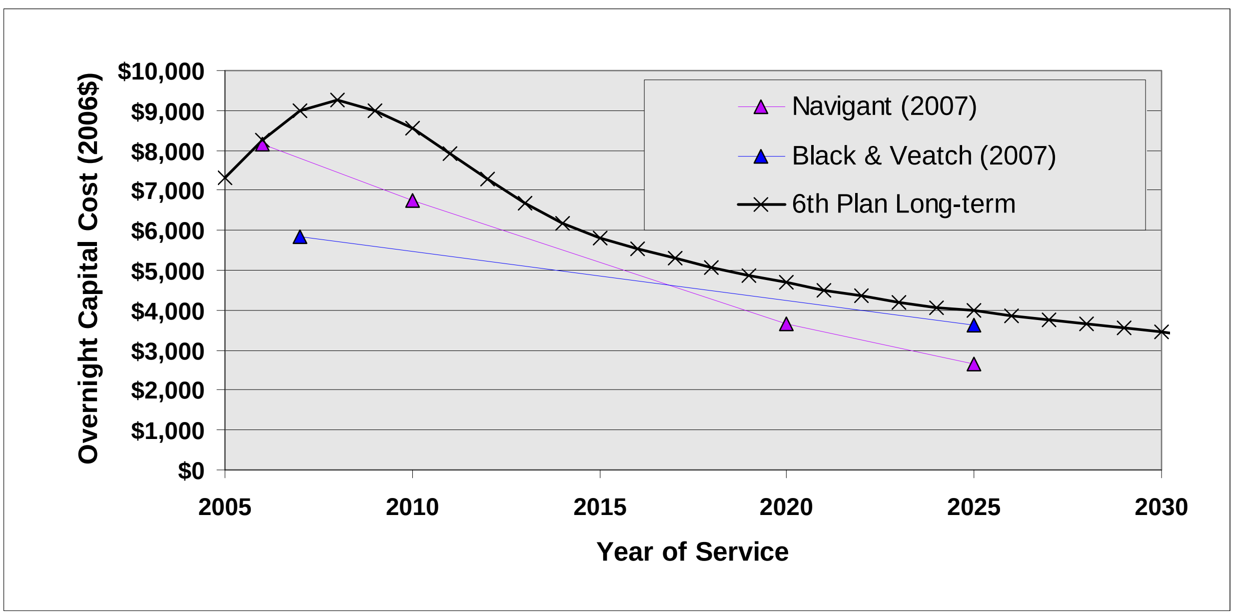



**Figure I-13: Forecast long-term capital costs of utility-scale solar photovoltaic plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for representative utility-scale solar photovoltaic plant are as follows:

**Development** (Site acquisition, permitting) - 12 mo., 1% of total plant cost

**Early Construction** (Procurement and site preparation) - 12 mo., 14% of total plant cost

**Committed Construction** (Construction and commissioning) - 12 mo., 85% of total plant cost

Costs are assumed to be set one year in advance of completion.

***Operating and Maintenance Cost:*** Operating and maintenance costs are assumed to be 0.4% of overnight capital cost. This is midway between reported O&M costs for the Arizona Public Service Springerville plant (0.26% of capital cost, including inverter replacement but using fixed mount modules), and International Energy agency estimates (0.5% of capital cost). This assumption yields $36/kW/yr (2008 base year). O&M costs are assumed to vary in real terms with total plant cost.

***Integration cost:*** Photovoltaic plants are assumed to require integration and load following services. The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-5. The cost of longer-term shaping services is not included in this estimate.

***Economic Life:*** The economic life of a utility-scale solar photovoltaic plant is assumed to be 25 years; limited by warranted cell life. One inverter replacement is likely to be required during the life of the plant.

***Development Potential:*** Utility-scale solar photovoltaic development potential is likely to be substantial; however, an assessment has not been undertaken for the Northwest. Because of the high cost of electricity from photovoltaic plants in the Northwest, and the availability of more cost-effective renewable resources, an estimate of developable potential was not needed for this plan. An assessment of potential may be desirable in the future when the cost of electricity from photovoltaic plants approaches parity with other low-carbon resources.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from a utility-scale solar photovoltaic power plant with a solar resource typical of southwestern Idaho and southeastern Oregon is shown in Table I-18. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal investment tax credit.

**Table I-18: Levelized Cost of Utility-scale Solar Photovoltaic Power Plants (Boise site)**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $376.36 | $10.27 | $14.53 | $0.00 | $401 |
| 2015 | $254.40 | $10.90 | $12.31 | $0.00 | $278 |
| 2020 | $205.13 | $11.22 | $11.38 | $0.00 | $228 |
| 2025 | $174.45 | $11.36 | $10.81 | $0.00 | $197 |
| 2030 | $150.75 | $11.41 | $10.39 | $0.00 | $173 |

## *Concentrating Solar Thermal Power Plant*

Parabolic trough concentrating solar thermal power plants are a commercially proven technology with over 20 years of operating history. Existing plants use a synthetic oil primary heat transfer fluid and a supplementary natural gas boiler in the secondary water heat transfer loop for output stabilization and extended operation into the evening hours.  Future plants are expected to benefit from higher collector efficiencies, higher operating temperatures (providing higher thermal efficiency and more economical storage) and economies of production.

Concentrating solar technologies (thermal and photovoltaic) require high direct normal solar irradiation for efficient operation.  Though the most promising sites are in the desert southwest, potentially suitable areas may be present in Bonneville's Nevada service territory (http://www.nrel.gov/csp/images/3pct_csp_nv.jpg.  Some evidence suggests possibly suitable sites in extreme southeastern Oregon.

***Reference Plant:*** The reference plant is a 100-megawatt dry-cooled parabolic trough concentrating solar thermal plant located in east-central Nevada in the vicinity of Ely.  Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and thence to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemmingway transmission projects.  Higher temperature heat transfer fluids such as molten salt are expected to be available by the earliest feasible date for energization of the necessary transmission (ca. 2015).  The reference plant is assumed to be equipped with and a 2.5 solar multiplier collector field[21] and thermal storage sufficient to support six to eight hours of full power operation.  This storage would allow output to be shifted to non-daylight hours, improve winter capacity factor, levelize output on intermittently cloudy days, and impart some firm capacity value.  No natural gas backup is provided since natural gas service is not available in the vicinity of the reference site[22].

***Capacity Factors and Temporal Output:*** Annual capacity factor and seasonal, daily and hourly output was estimated using the NREL Solar Advisor Model (https://www.nrel.gov/analysis/sam/) yields an annual average capacity factor of 35.5% for the Ely site.  Output is highly seasonal, even with a collector field solar multiplier of 2.5.  However, as shown in Table I-19 and Figure I-15, the storage facility effectively shifts output to approximate Northwest daily load shape (compare with photovoltaic output without storage in Table I-17 and Figure I-11).  Periods of negative output in Table I-19 are plant parasitic loads in excess of gross solar output.

[21] A collector field with rated output 2.5 times the rated output of the power generation block.  The surplus output of the collector field during peal solar hours serves to recharge the storage plant.

[22] The Ely vicinity was selected as a reference site because of the availability of reasonably favorable solar resource, suitable sites and the likelihood that the SWIP or a parallel transmission project would move forward.  Subsequent analysis using the NREL Solar Advisor Model suggests possible alternatives including the Reno area with new transmission via the existing Alturas corridor.  The Reno alternative may have somewhat better solar irradiation plus the advantage of natural gas service permitting use of natural gas backup.

**Figure I-14: Estimated monthly net energy production for 100 MW parabolic trough plant with 2.5 solar multiplier and six hours of storage located near Ely, NV**

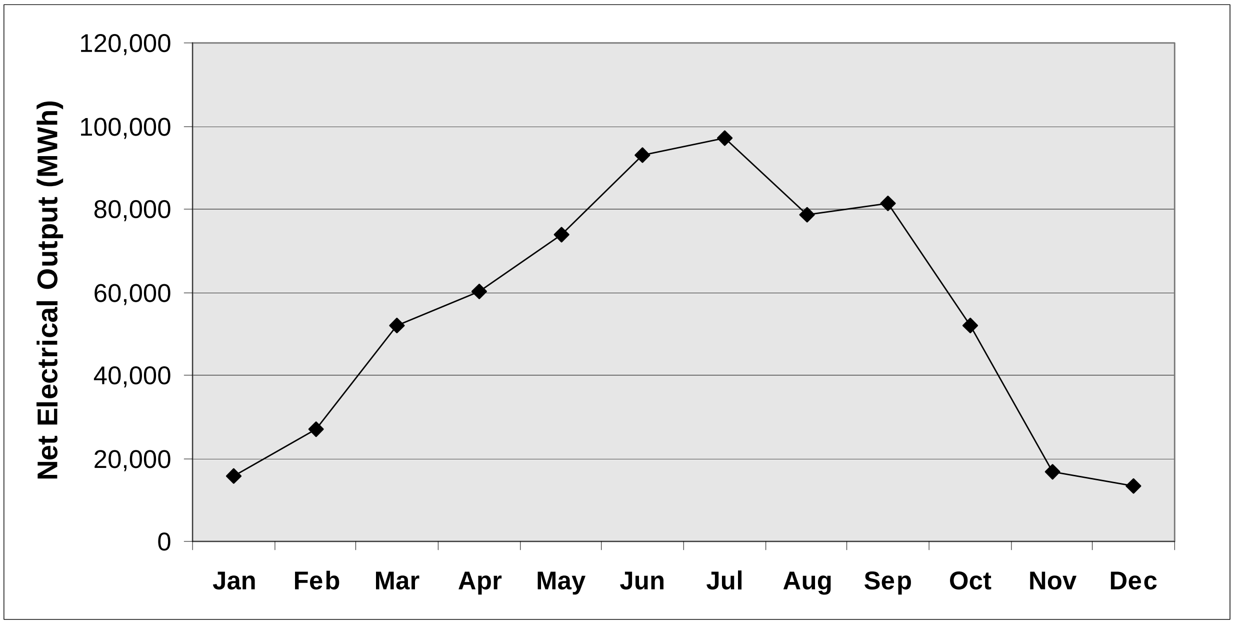
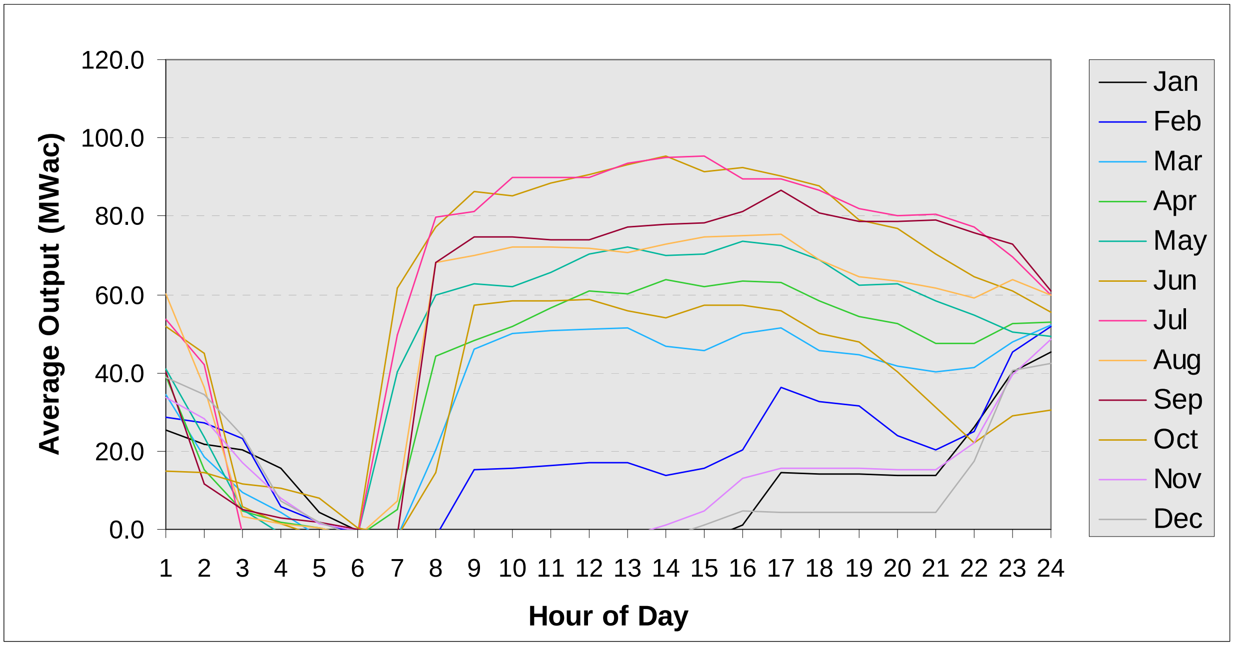



**Table I-19: Average hourly energy output by month (MW) (Ely location)**

| Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 25.3 | 28.8 | 34.6 | 39.0 | 41.0 | 51.8 | 53.6 | 60.2 | 40.3 | 14.9 | 33.9 | 38.7 |
| 2 | 21.8 | 27.3 | 18.6 | 15.1 | 23.5 | 45.0 | 42.1 | 36.1 | 11.6 | 14.4 | 28.2 | 34.6 |
| 3 | 20.2 | 23.3 | 9.5 | 4.6 | 5.0 | 5.8 | -1.0 | 3.4 | 5.2 | 11.6 | 17.0 | 23.8 |
| 4 | 15.5 | 5.7 | 4.4 | 1.7 | -1.1 | 1.4 | -1.8 | 1.6 | 3.1 | 10.6 | 7.8 | 7.3 |
| 5 | 4.3 | 1.8 | -1.8 | 0.3 | -1.8 | -1.8 | -1.8 | 0.4 | 1.7 | 8.1 | 1.6 | 1.7 |
| 6 | -0.3 | -1.1 | -1.8 | -1.8 | -1.6 | -1.3 | -1.6 | -1.8 | 0.1 | 0.3 | -0.4 | -1.8 |
| 7 | -1.8 | -1.8 | -1.8 | 5.2 | 40.3 | 61.5 | 49.6 | 7.4 | -1.3 | -1.8 | -1.8 | -1.8 |
| 8 | -1.8 | -1.7 | 20.4 | 44.1 | 59.7 | 77.2 | 79.9 | 68.2 | 68.3 | 14.3 | -1.7 | -1.8 |
| 9 | -2.0 | 15.3 | 45.9 | 48.2 | 62.6 | 86.4 | 81.2 | 70.0 | 74.8 | 57.5 | -2.2 | -1.9 |
| 10 | -2.5 | 15.5 | 49.9 | 51.8 | 61.9 | 85.1 | 89.9 | 72.3 | 74.6 | 58.2 | -2.0 | -2.1 |
| 11 | -2.0 | 16.3 | 50.9 | 56.6 | 65.6 | 88.4 | 89.9 | 72.0 | 74.1 | 58.4 | -2.0 | -1.6 |
| 12 | -1.8 | 16.9 | 51.1 | 60.8 | 70.4 | 90.7 | 90.1 | 71.6 | 73.9 | 58.7 | -1.8 | -1.6 |
| 13 | -1.9 | 17.0 | 51.6 | 60.3 | 72.3 | 93.1 | 93.4 | 70.5 | 77.1 | 55.8 | -2.0 | -1.8 |
| 14 | -2.2 | 13.6 | 46.8 | 64.0 | 70.1 | 95.3 | 94.8 | 72.7 | 77.9 | 54.0 | 1.2 | -2.2 |
| 15 | -2.7 | 15.4 | 45.7 | 61.9 | 70.2 | 91.4 | 95.3 | 74.5 | 78.3 | 57.2 | 4.7 | 1.1 |
| 16 | 1.3 | 20.3 | 50.0 | 63.6 | 73.5 | 92.3 | 89.6 | 75.1 | 81.3 | 57.1 | 12.9 | 4.7 |
| 17 | 14.6 | 36.4 | 51.4 | 63.1 | 72.6 | 90.4 | 89.4 | 75.5 | 86.5 | 55.9 | 15.7 | 4.5 |
| 18 | 14.2 | 32.5 | 45.8 | 58.4 | 69.0 | 87.8 | 86.6 | 68.7 | 80.8 | 50.2 | 15.6 | 4.4 |
| 19 | 14.0 | 31.5 | 44.6 | 54.5 | 62.3 | 78.9 | 81.8 | 64.4 | 78.8 | 47.9 | 15.5 | 4.3 |
| 20 | 13.9 | 24.0 | 41.7 | 52.6 | 62.6 | 77.0 | 80.0 | 63.6 | 78.6 | 40.4 | 15.4 | 4.3 |
| 21 | 13.8 | 20.2 | 40.4 | 47.4 | 58.2 | 70.2 | 80.3 | 61.7 | 78.9 | 31.1 | 15.3 | 4.4 |
| 22 | 26.0 | 24.9 | 41.4 | 47.3 | 54.6 | 64.5 | 77.2 | 59.1 | 75.8 | 22.0 | 22.1 | 17.3 |
| 23 | 40.3 | 45.3 | 47.8 | 52.5 | 50.4 | 61.1 | 69.6 | 63.6 | 72.7 | 28.9 | 39.7 | 40.7 |
| 24 | 45.5 | 52.0 | 52.3 | 53.0 | 49.3 | 55.4 | 59.8 | 60.0 | 61.0 | 30.6 | 48.5 | 42.6 |

**Figure I-15: Average hourly energy output by month (Ely location)**




***Unit Commitment Parameters***: Concentrating solar thermal plants are assumed to operate as must-run units.

***Total Plant Cost:*** The total plant cost of a representative parabolic trough concentrating solar plant is estimated to be $4,700/kW (2008 price year). Publically-available cost information was located for 3 proposed or recently-constructed parabolic trough concentrating solar plants, ranging in size from 64 to 250 MW. Two recent generic cost estimates for parabolic trough concentrating solar plants were also located. These costs, normalized as total plant cost per net kW capacity in 2006 dollars are plotted by the vintage of the cost data in Figure I-15. Though data are few, a reasonably clear trend of increasing costs from 2004 through 2007 is evident, marked in particular by the increasing estimates for Nevada Solar One. The trend is less clear beyond 2007 and could be interpreted as leveling off or even declining. Continued escalation through price year 2008 was chosen for the plan, because of the continued escalation during this period observed for other resource types and because the higher estimate for 2008 is for a plant employing dry cooling, whereas the lower estimate is for a plant employing evaporative cooling. Though evaporative cooling is less expensive than dry cooling, and results in more efficient plant operation, it is likely that plants located in arid areas (as is the representative plant) will increasingly employ dry cooling. Prices are shown declining in 2009 in accordance with the CERA near-term power plant capital cost index.

The forecast of future cost (Figure I-16) is based on the interaction of several factors including continued downward pressure in the near-term due to economic conditions, upward pressure in the near-term due to incorporation of thermal storage, and downward pressure through the planning period attributable to technological improvements, economies of scale, and economies of production. Figure I-16 illustrates the basic forecast described above, continuing to drop through 2011 when equilibrium prices are assumed to be achieved, consistent with other resource types. The horizontal line extending to the right from this point represents forecast capital costs if no further technological improvement or economies of scale are assumed. A long term forecast of the price effects of technological improvements and economies of scale and production for parabolic trough concentrating solar thermal plants appears in a renewable energy assessment prepared for the Arizona Public Service Company, Salt River Project and Tucson Electric Power Corporation (Black & Veatch, 2007). This forecast is plotted in Figure I-16 with interpolated values between the four forecast points (2011, 2015, 2020 and 2025). Because this forecast was prepared prior to the 2008 economic downturn, the shape, rather than the magnitude of the forecast is used to modify the "no technological improvement" curve to yield the combined forecast of future capital cost used for the final Sixth Power Plan.

**Figure I-16: Published and forecast capital costs of parabolic trough concentrating solar power plants**

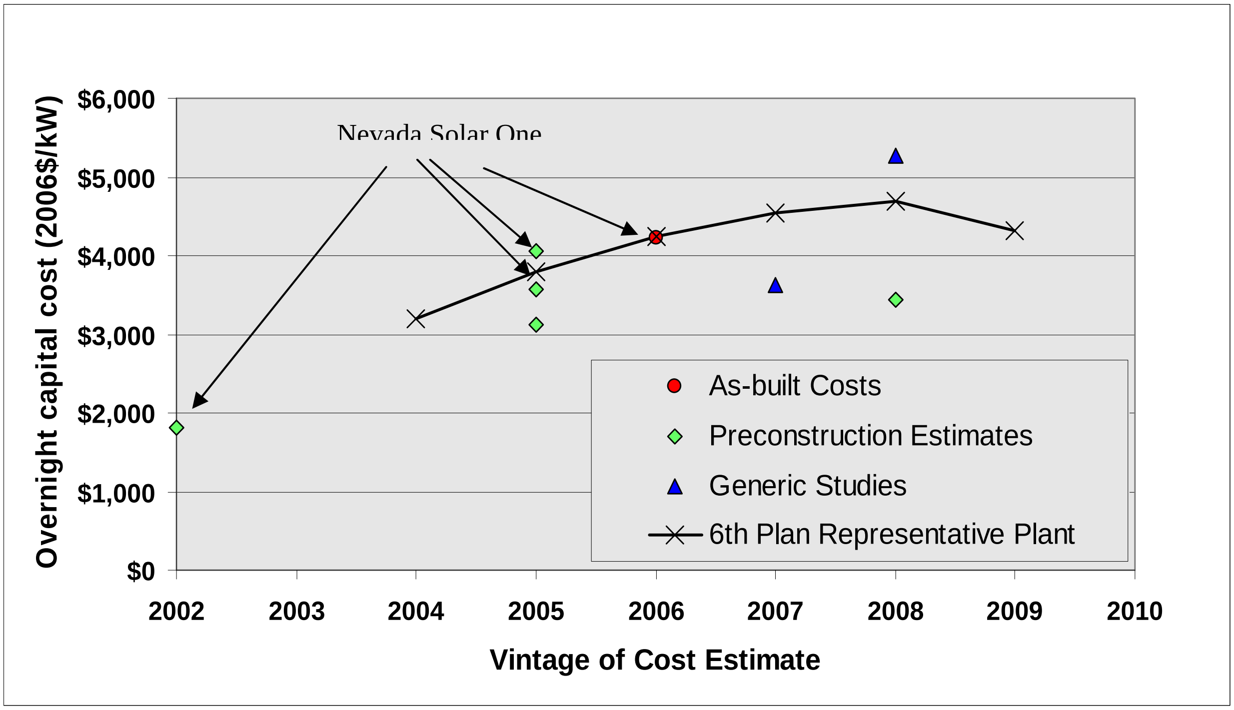
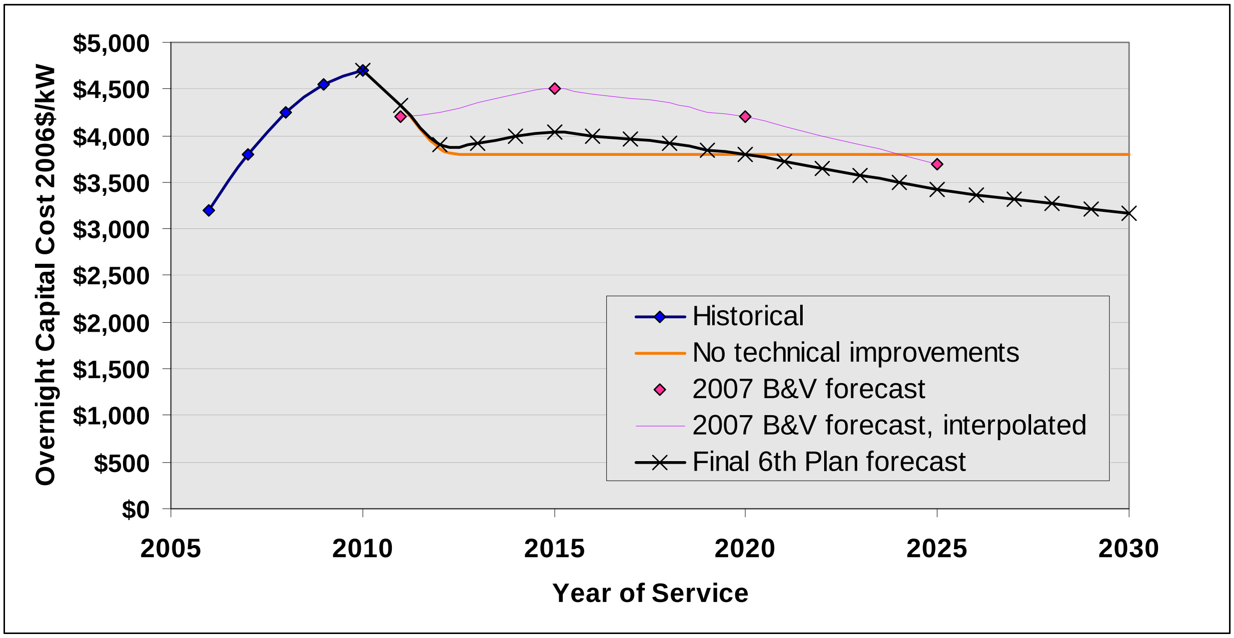


**Figure I-17: Forecast long-term capital cost of parabolic trough concentrating solar power plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for representative utility-scale solar photovoltaic plant are as follows:

> **Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 24 mo., 2% of total plant cost
>
> **Early Construction** (Equipment order, site preparation, interconnection and infrastructure construction) - 8 mo. (possible 4 month overlap with development period, 19% of total plant cost
>
> **Committed Construction** (Major equipment installation, commissioning) - 20 mo., 79% of total plant cost

The construction period was based on CEC (2007). Total plant costs are assumed to be established two years in advance of completion

The combined development and construction schedule and cash flow for a solar thermal plant and the associated long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of solar thermal capacity development is assumed to be such that the generating capacity enters service coincidental with the transmission line. The second phase is optional buildout of the remaining 50% of solar thermal capacity potentially served by the transmission line in 250 MW increments.

***Operating and Maintenance Cost:*** Operating and maintenance costs are based on values reported in Table 5-2 of NREL, 2006 for a 100 MW parabolic trough concentrating solar thermal plant with thermal storage. Labor (including administration), service contracts, equipment and materials, including capital replacement items are 1.3% of capital cost. This yields a fixed O&M cost (exclusive of property taxes and insurance) $60/kW/yr for the 2008 price year. Water treatment is assumed to be a variable cost and is rounded to $1.00/MWh. Fixed O&M cost is assumed to vary in real terms with total plant costs. Variable O&M cost is assumed to remain constant in real terms.

***Integration Cost:*** The thermal storage capacity of the representative solar thermal plant is assumed to eliminate the need for the incremental regulation and load following.

***Economic Life:*** The economic life of a parabolic trough concentrating solar thermal plant is assumed to be 30 years.

***Transmission:*** New long-distance transmission would be required to deliver power to Northwest load centers from a solar thermal power plant near Ely, Nevada. Transmission configurations, alignments and basic cost assumptions are described in the Transmission section, above. Transmission costs and losses, including delivery within the region, are provided in Table I-20.

**Table I-20: Transmission costs and losses (Ely location)**

| Load Center | Fixed Transmission Costs ($/kW/yr) | Variable Transmission Costs ($/MWh) | Transmission Losses |
|---|---|---|---|
| Southern Idaho | $102 | $1.00 | 4.0% |
| Oregon & Washington | $189 | $1.00 | 6.5% |

***Development Potential:*** Though environmental considerations will constrain land on which concentrating solar thermal plants can be developed, the development potential is likely to be very substantial. Because of the high cost of electricity from solar thermal plants, and the availability of more cost-effective renewable resources, an estimate of developable potential was not sought for this plan. The earliest availability of the resource to the Northwest is assumed to be 2015, constrained by transmission line development lead time.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from concentrating solar thermal power plants is shown in Table I-21. The cost estimates are based on investor-owned utility financing. 2010 service year cases include federal investment tax credit.

**Table I-21: Levelized Cost of Concentrating Solar Thermal Power Plants**

| Case | Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmissio n and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| NV > S. ID | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $146.20 | $0.99 | $41.95 | $0.00 | $189 |
| | 2020 | $128.05 | $1.00 | $41.34 | $0.00 | $170 |
| | 2025 | $116.24 | $1.00 | $40.98 | $0.00 | $158 |
| | 2030 | $105.48 | $1.01 | $40.70 | $0.00 | $147 |
| NV > OR/WA | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $146.20 | $0.99 | $79.38 | $0.00 | $227 |
| | 2020 | $128.05 | $1.00 | $78.38 | $0.00 | $207 |
| | 2025 | $116.24 | $1.00 | $77.82 | $0.00 | $195 |
| | 2030 | $105.48 | $1.01 | $77.39 | $0.00 | $183 |

## *Wind Power Plants*

Wind power is modeled by defining a reference wind plant then applying transmission costs and losses appropriate to the location of the wind resource and the load center served. Plant capacity factors are adjusted to reflect the quality of the various wind resource areas. Five wind resource areas were assessed, including the Columbia basin (eastern Washington and Oregon), southern Idaho, central Montana, southern Alberta, and eastern Wyoming. The combinations of wind resource areas, transmission, and points of delivery considered are shown in Table I-3 in the Transmission section.

***Reference Plant:*** The 100 MW reference plant consists of arrays of conventional three-blade wind turbine generators, in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers and support facilities.

***Capacity Factors and Temporal Output:*** The annual average capacity factors used for the five resource areas are shown in Table I-22. These were taken from the Council's 2007 Biennial Monitoring Report (NPCC, 2007). The Biennial Monitoring Report values were based on assumptions of the Fifth Power Plan adjusted upward by 2% to reflect the introduction of larger, more efficient and reliable turbines, and improvements in turbine siting. The capacity factors shown in Table I-22 are net at the plant interconnection and are derated for transmission losses to the point of wholesale delivery using the transmission loss factors described in the transmission section. Hourly output estimates for the AURORA$^{xmp®}$ price forecasting model were developed from hourly wind output estimates for various subregional locations developed for the WECC Transmission Expansion Planning Policy Committee (TEPPC). The TEPPC hourly output estimates were based on mesoscale synthetic wind speed data developed by the National Renewable Energy Laboratory. The TEPPC hourly output values were not used directly, however, because the resulting annual capacity factors are substantially lower than historical capacity factors for Northwest sites. Rather, the TEPPC hourly output values were scaled upward to yield the capacity factors shown in Table I-22.

**Table I-22: Wind average annual capacity factors**

| Wind Resource Area > | Columbia Basin | Southern Idaho | Central Montana | Southern Alberta | Eastern Wyoming |
|---|---|---|---|---|---|
| Average annual capacity factor (net plant output) | 32% | 30% | 38% | 38% | 38% |

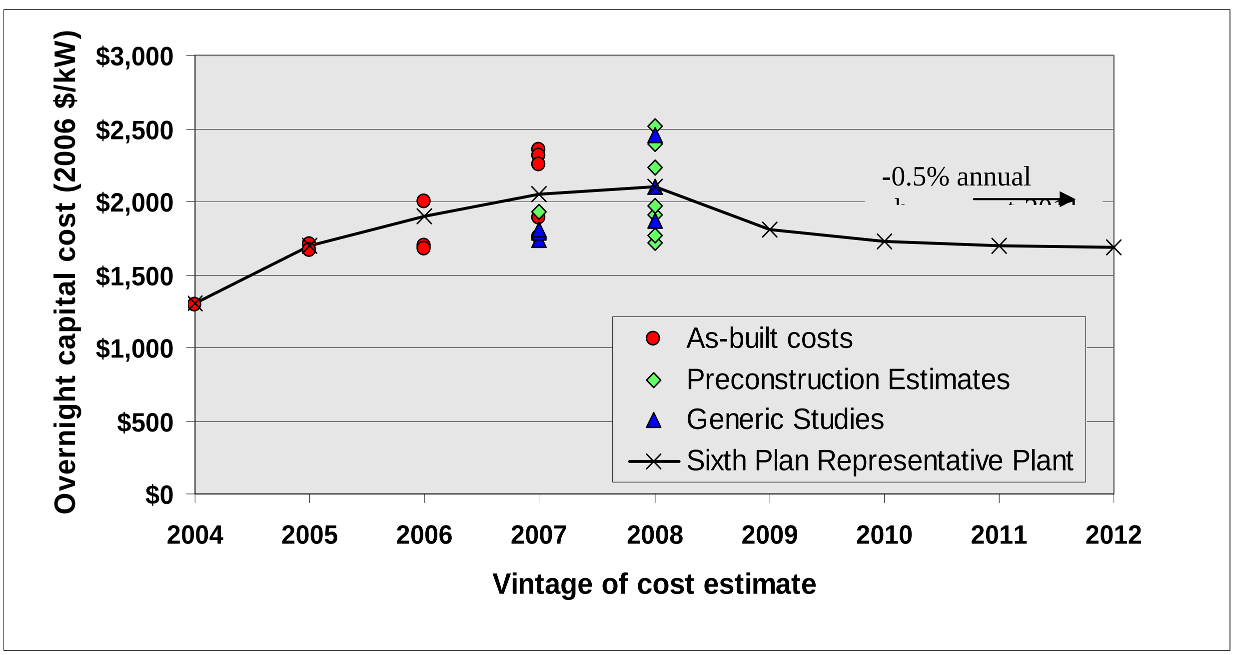
***Firm Capacity Value:*** 5% of installed capacity as adopted by the Northwest Resource Adequacy Forum.

***Unit Commitment Parameters*:** Wind power plants are assumed to operate as must-run units.

***Total Plant Cost:*** The total plant cost of the reference wind plant is $2,100/kW installed capacity (2008 price year). This estimate is based on a sample of 11 reported as-built plant costs and 8 published preconstruction estimates from 2004 through 2008. Five generic estimates of wind plant development costs were also obtained. Two of the latter were range estimates consisting of low and high bound costs. These costs, normalized as total plant cost per net kW capacity in 2006 dollars, are plotted by the vintage of the cost data in Figure I-18. A well-defined increase in construction costs from 2004 through mid-2008 is evident. Analysis of the factors underlying the increase in wind plant costs during this period is provided in the Biennial Monitoring Report (NPCC, 2007).

A cost uncertainty range from -19% to +24% ($1700 to $2500 in 2008) is used for Regional Portfolio Model studies. The range is based on the range of observations for 2008.

**Figure I-18: Published and forecast capital costs of wind power plants**



Costs are forecast to decline from 2008 highs through 2011, reaching an average of 2004 and 2008 costs. This price level is assumed to be in equilibrium. Thereafter, technological improvements are assumed to reduce total plant costs by 0.5% per year, on average, reflecting a 5% learning rate for wind technology.

***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for a wind plant (exclusive of long-distance transmission, if any) are as follows:

> **Development** (Site options to completion of resource assessment): - 24 mo., 5% of total plant cost
>
> **Early Construction** (WTG order to first WTG shipment) - 12 mo., 16% of total plant cost
>
> **Committed Construction** (WTG shipment to commercial service) - 18 mo., 79% of total plant cost

The combined development and construction schedule and cash flow for a wind resource requiring long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the installed wind capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of wind capacity development is assumed to be such that the wind capacity enters service coincidental with the transmission line. The second phase is optional build out of the remaining 50% of wind capacity potentially served by the transmission line in 250 MW increments.

***Operating and Maintenance Cost:*** Fixed O&M costs include plant operation and maintenance costs and capital replacement costs, exclusive of property taxes and insurance. The estimated fixed O&M cost of $40/kW/yr is based on the fixed O&M cost for wind plants used for the Fifth Power Plan ($20/kWh/yr), escalated by observed 2004 - 2008 wind plant capital cost escalation (108% nominal) and rounded to $40/kW/yr to yield overall annual O&M costs (including property taxes and insurance) of 2.5% of total plant cost. This percentage is within the range of 2 - 3.5% of total energy cost and 20 - 25% of total energy costs over the life of the plant cited in IEA, 2008b. Fixed O&M cost is assumed to vary in real terms with total plant cost.

The variable O&M cost of $2.00/MWh is intended to represent land rent. Land rent is reported to typically range between 2 - 4% of the gross revenue from wind turbine generator (Wind Powering America, http://www.windpoweringamerica.gov/pdfs/wpa/34600_landowners_faq.pdf). $2.00 per MWh is approximately 2% of busbar revenue requirements at the current cost of wind. Because construction costs are expected to decline and variable O&M remains constant in the analysis, the low end value was selected.

***Integration cost:*** The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-5. The cost of longer-term shaping services is not included in this estimate.

***Economic Life:*** The economic life of a wind plant is assumed to be 20 years.

***Development Potential:*** The estimated development potential for the various blocks of wind is shown in Table I-23. Capacity and energy shown as “available” is estimated developable capacity in excess of operating and committed (under construction) capacity as of February 2009.

The Columbia Basin resource potential for delivery to western Oregon and Washington load centers shown in Table I-23 is limited by new east - west transmission capacity that could be developed at current embedded transmission cost. This capacity is the sum of unconstructed projects with firm Bonneville transmission rights (estimated to be 1,250 MW) and new capacity created by the West of McNary, Little Goose and I-5 Corridor reinforcements (approximately 4,860 MW). This total was reduced by the capacity of unconstructed projects with announced long-term sales to California. (Projects selling to or owned by California utilities are assumed to hold firm transmission rights to California. It is not clear that this is necessarily so because California renewable portfolio standards and administrative rules allow delivery of energy any time within the calendar year, thus permitting use of conditional firm transmission.)

The Columbia basin potential for delivery to eastern Oregon and Washington load centers, and Idaho and Montana potential for local (sub-regional) delivery are each assumed to be limited to a maximum penetration of 20% of forecast local peak hourly load at the end of the planning period. The variable resource integration costs of Table I-5 are assumed sufficient to cover integration costs to this level of penetration.

The “remote” wind resource blocks using new long-distance transmission were provisionally limited by the capacity of a single transmission circuit, pending initial analysis of resource cost-effectiveness using the Resource Portfolio Model. In only one case (Low Conservation), did renewable resource development exceed the estimated availability of wind from sources not involving construction of new long-distance transmission. For this reason, further assessment of potential limits was not undertaken.

An issue needing further consideration is the prospect of additional long-term sales of Northwest wind to California utilities for compliance with California renewable portfolio standards. Various outcomes are possible, involving California renewable energy credit policy, the proposed increase in California renewable portfolio standard targets, current intertie capacity and the future competitiveness of Northwest wind vs. California and Southwestern solar from the perspective of California utilities.

**Table I-23: Wind power development potential**

| Wind Resource Area | Load | Available Capacity (MW) | Available Energy (MWa) | Limiting Factors | Earliest Service |
|---|---|---|---|---|---|
| Columbia Basin | Westside OR/WA | 4060 | 1300 | New transmission to Westside @ embedded cost | 2010 |
| Westside OR/WA | Westside OR/WA | 200 | 60 | Allowance | 2010 |

| | | | | | |
|---|---|---|---|---|---|
| Columbia Basin | Eastside OR/WA | 340 | 110 | 20% of 2029 peak load | 2010 |
| S. Idaho | S. Idaho | 720 | 220 | 20% of 2029 peak load | 2010 |
| Montana | Montana | 215 | 80 | 20% of 2029 peak load | 2010 |
| Montana | S. Idaho | 1500 | 570 | Per 500kV AC ckt | 2015 |
| Montana | OR/WA | 1500 | 570 | Per 500kV AC ckt | 2015 |
| Wyoming | S. Idaho | 1500 | 570 | Per 500kV AC ckt | 2015 |
| Wyoming | OR/WA | 1500 | 570 | Per 500kV AC ckt | 2015 |
| Alberta | OR/WA | 2000 | 760 | Per +/-500kV DC ckt | 2015 |

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from the various wind resource areas to Northwest load centers is shown in Table I-24.   The cost estimates are based on investor-owned utility financing.  2010 service year cases include federal production tax credit.

**Table I-24: Levelized cost of Wind Power Plants**

| Case | Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| Wind (MT Local) | 2010 | $77.05 | $10.62 | $6.76 | $0.00 | $94 |
| | 2015 | $71.20 | $11.33 | $6.75 | $0.00 | $89 |
| | 2020 | $69.47 | $11.70 | $6.74 | $0.00 | $88 |
| | 2025 | $67.81 | $11.83 | $6.72 | $0.00 | $86 |
| | 2030 | $66.20 | $11.89 | $6.71 | $0.00 | $85 |
| Wind (OR/WA Local) | 2010 | $93.24 | $10.62 | $8.02 | $0.00 | $112 |
| | 2015 | $84.18 | $11.33 | $7.97 | $0.00 | $103 |
| | 2020 | $82.13 | $11.70 | $7.95 | $0.00 | $102 |
| | 2025 | $80.15 | $11.83 | $7.93 | $0.00 | $100 |
| | 2030 | $78.24 | $11.89 | $7.92 | $0.00 | $98 |
| Wind (S. ID Local) | 2010 | $100.08 | $10.62 | $8.56 | $0.00 | $119 |
| | 2015 | $89.66 | $11.33 | $8.49 | $0.00 | $109 |
| | 2020 | $87.47 | $11.70 | $8.46 | $0.00 | $108 |
| | 2025 | $85.36 | $11.83 | $8.44 | $0.00 | $106 |
| | 2030 | $83.32 | $11.89 | $8.43 | $0.00 | $104 |
| Wind (MT> S. ID) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $34.17 | $0.00 | $116 |
| | 2020 | $69.47 | $11.18 | $34.17 | $0.00 | $115 |
| | 2025 | $67.81 | $11.31 | $34.16 | $0.00 | $113 |
| | 2030 | $66.20 | $11.37 | $34.25 | $0.00 | $112 |
| Wind (MT > OR/WA via CTS upgrade) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $46.46 | $0.00 | $128 |
| | 2020 | $69.47 | $11.18 | $46.37 | $0.00 | $127 |
| | 2025 | $67.81 | $11.31 | $46.28 | $0.00 | $125 |
| | 2030 | $66.20 | $11.37 | $46.29 | $0.00 | $124 |
| Wind (WY> S. ID) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $38.98 | $0.00 | $121 |
| | 2020 | $69.47 | $11.18 | $38.98 | $0.00 | $120 |
| | 2025 | $67.81 | $11.31 | $38.98 | $0.00 | $118 |
| | 2030 | $66.20 | $11.37 | $39.09 | $0.00 | $117 |
| Wind (AB > OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $56.17 | $0.00 | $138 |
| | 2020 | $69.47 | $11.18 | $56.21 | $0.00 | $137 |
| | 2025 | $67.81 | $11.31 | $56.24 | $0.00 | $135 |
| | 2030 | $66.20 | $11.37 | $56.44 | $0.00 | $134 |
| Wind (MT > OR/WA via S. ID) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $64.85 | $0.00 | $147 |
| | 2020 | $69.47 | $11.18 | $64.87 | $0.00 | $146 |
| | 2025 | $67.81 | $11.31 | $64.88 | $0.00 | $144 |
| | 2030 | $66.20 | $11.37 | $65.08 | $0.00 | $143 |
| Wind WY > OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | $71.20 | $10.84 | $72.11 | $0.00 | $154 |
| | 2020 | $69.47 | $11.18 | $72.13 | $0.00 | $153 |
| | 2025 | $67.81 | $11.31 | $72.15 | $0.00 | $151 |
| | 2030 | $66.20 | $11.37 | $72.37 | $0.00 | $150 |

# *Waste Heat Energy Recovery Cogeneration*

Certain industrial processes and engines reject energy at sufficient temperature and volume to justify capturing the energy for electricity production, a process known as Recovered Energy Generation (REG), and a form of cogeneration. Candidate sources of high and medium-temperature waste heat potentially suitable for power generation include: cement kilns, glass furnaces, aluminum smelters, metals refining furnaces, open hearth steel furnaces, steel heating furnaces, hydrogen plants, waste incinerators, steam boiler exhaust, gas turbines and reciprocating engine exhaust, heat treating and annealing furnaces, drying and baking ovens, and catalytic crackers. While many of these facilities are usually equipped with recuperators, regenerators, waste-heat recovery boilers, and other devices to capture a portion of the reject heat, bottoming-cycle cogeneration could also be installed on some. Recovered energy generation is attractive because of its efficiency, baseload operation, and little, if any, incremental air emissions or carbon dioxide production. Heat recovery boilers with steam-turbine generators are the conventional approach to using waste heat for electric power generation. However, small-scale, modular organic Rankine cycle power plants (Ormat and others) suitable for lower-temperature energy sources have expanded the potential applications for recovered energy generation.

***Reference Plant:*** The reference plant is a 5 MW organic Rankine cycle (ORC) generating plant using 900$^{o}$ F gas turbine exhaust heat from a natural gas pipeline compressor station as an energy source. The plant is provided with dry cooling.

***Fuel:*** The operator of the waste heat recovery plant is assumed to pay a fee to the owner of the host facility for the usable energy content of the waste gas stream. This cost is included in Operating and Maintenance cost

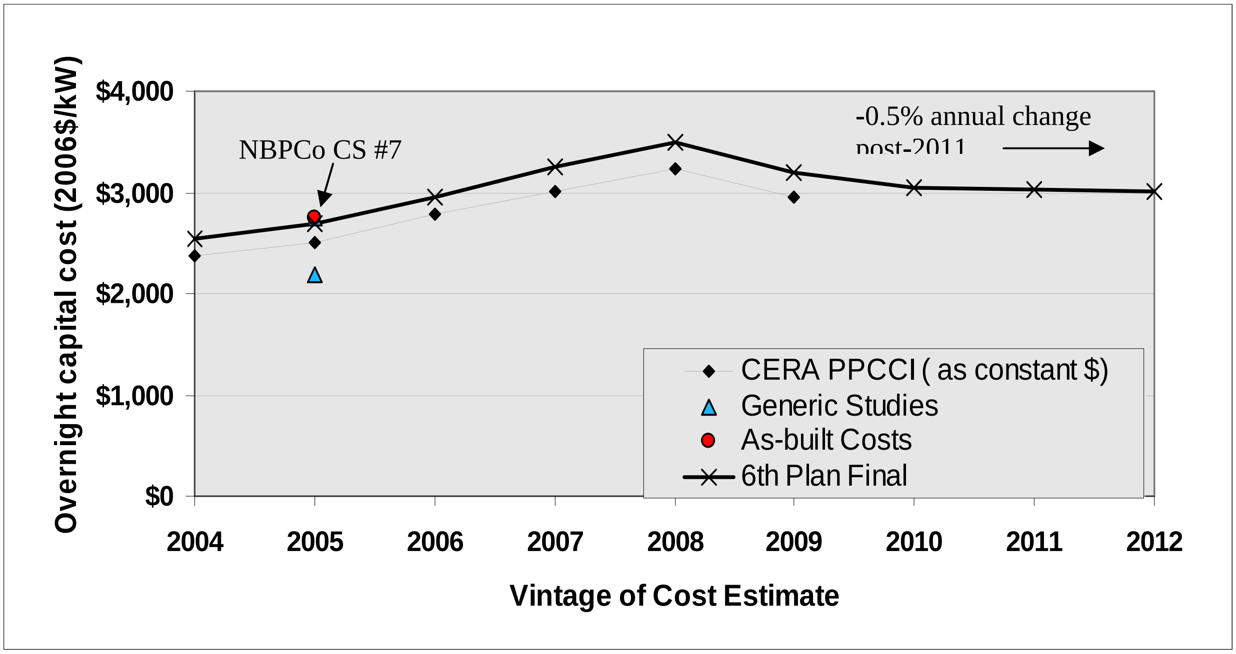
***Heat Rate:*** The representative heat rate 38,000 Btu/kWh for an ORC plant operating with the reference plant assumptions (900$^{o}$F GT exhaust temperature, dry cooling) is based on the average annual performance of the ORC heat recovery project at the Northern Border Pipeline Compressor Station #7 (ORNL, 2007). Because the cost of the waste heat “fuel” is assumed to be a royalty payment based on electricity production, a heat rate assumption is not required for energy production cost calculations.

***Unit Commitment Parameters*:** CHP power plants are assumed to operate as must-run units at an average capacity factor of 80%. The expected annual energy production for Trailblazer Pipeline Peetz compressor station is 27,600 MWh (3.15 MWa) (Colorado Energy News, 2009). The installed capacity at this station is 4 MW, giving a 79% capacity factor. This was rounded to 80% for the reference plant. A higher (90%) capacity factor is reported for the Northern Border Compressor Station #7 plant, though the load factor in pipelines serving the Midwestern market may be higher than those of Western lines.

***Total Plant Cost:*** The total plant cost of the reference plant is $3,500/kW installed capacity (2008 price year). This cost is based on the installed cost of the Basin Electric Project at the Northern Border Pipeline Company’s Compressor Station #7 (ORNL, 2007). The cost of this project, normalized to overnight 2006 dollars, is plotted in Figure I-19 as the “as-built” cost point. A second source was located (INGAA, 2008) and is plotted as the generic costs in Figure I-19, however, the INGAA capital costs are based on the Basin Electric Project and are not adjusted for escalation despite the later date of the report. As illustrated in Figure I-19, the reference 2008 price year cost was derived by approximating the effect of the CERA Power Plant Construction Cost Index (excluding nuclear)[23] on the 2005 as-built cost of the Basin Electric Project.

Costs are forecast to decline from 2008 highs through 2011, reaching an average of 2004 and 2008 costs. This price level is assumed to be in equilibrium. Thereafter, technological improvements are assumed to reduce total plant costs by 0.5% per year, on average, reflecting a 5% learning rate for organic Rankine cycle technology.

**Figure I-19: Published and forecast capital costs of representative waste heat recovery plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for the representative waste heat recovery plant are as follows:

**Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 24 mo., 5% of total plant cost

**Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction and installation of compressor turbine exhaust diversion valves and ducting) - 12 mo., 30% of total plant cost

**Committed Construction** (Major equipment installation, commissioning) - 12 mo., 65% of total plant cost

23 http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429

The development and construction schedule is based on gas turbine assumptions, but with an extended development period reflecting the complexities of three-party development (developer, pipeline owner, and purchasing utility) and an extended early construction period including installation of compressor turbine exhaust diversion valves and ducting.

***Operating and Maintenance Cost:*** O&M costs are estimated to be $8.00/MWh. Operating and maintenance costs (exclusive of property taxes and insurance) include plant O&M costs and payments to the pipeline owner for the use of the site and energy supply. INGAA, 2008 cites $0.005/kWh ($5/MWh) as typical pipeline company compensation and 0.002/kWh ($2/MWh) as a typical O&M cost . A range of possible O&M costs of $0.001 - 0.005/kWh ($1 - 5/MWh) is cited. The O&M costs were increased by 30% to account for general and administrative costs, and rounded up to the nearest dollar. No basis for disaggregating fixed and variable components was located. O&M costs are asssumed to remain constant in real terms.

***Economic Life:*** The economic life of a heat recovery cogeneration plant is assumed to be 20 years; limited by uncertainty regarding host facility viability.

***Development Potential:*** An inventory of potential Northwest opportunities for the development of recovered energy generation was not located. Opportunities are known to exist, for example, more than 50 natural gas pipeline compressor stations are located in the Northwest, none of which is known to have heat recovery generation installed. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about five megawatts in capacity, suggesting a potential of tens to low hundreds of megawatts. Cement kilns, steel processing facilities, and glass furnaces offer additional possibilities.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from waste heat energy recovery cogeneration power plants is shown in Table I-25. The cost estimates are based on investor-owned utility financing.

**Table I-25: Levelized Cost of Waste Heat Energy Recovery Cogeneration Power Plants**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | $58.82 | $0.99 | $3.61 | $0.00 | $63 |
| 2015 | $58.82 | $0.99 | $3.61 | $0.00 | $63 |
| 2020 | $57.53 | $0.99 | $3.59 | $0.00 | $62 |
| 2025 | $56.31 | $0.99 | $3.57 | $0.00 | $61 |
| 2030 | $55.12 | $1.00 | $3.56 | $0.00 | $60 |

## *Coal-fired Steam-electric Plants*

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 facility, a furnace and steam generator, and a steam turbine-generator. Coal is ground (e.g., pulverized) 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. Newer units are typically equipped with low-NOx burners, sulfur dioxide removal equipment, and electrostatic precipitators or baghouses for particulate removal. 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. Most western coal-fired plants are sited near the mine-mouth, though some plants are supplied with coal by rail at intermediate locations between mine-mouth and load centers.

Most existing 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. Several supercritical units 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. The majority of new North American coal capacity now supercritical technology.

***Reference Plant:*** A single 450 MW net supercritical pulverized coal-fired power plant at a greenfield site. This plant is equipped with low-NOx burners, overfire air, and selective catalytic reduction for control of nitrogen oxides. The plant would be provided with flue gas de-sulfurization, fabric filter particulate control, and activated charcoal injection for reduction of mercury emissions. The capital costs include a switchyard and transmission interconnection.

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.

***Fuel:*** The reference plant is assumed to be fuelled by western subbituminous coal. Coal price forecasts are described in Chapter 2 and Appendix A.

***Heat Rate:*** The heat rate of 9,000 Btu/kWh is from Exhibit 3-5 of EPA, 2006 (Supercritical pulverized coal unit using subbituminous coal).

***Availability Parameters:*** Availability parameters (lifecycle averages) are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all coal units. They are as follows:

Scheduled maintenance outages - 35 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 40 hours

Equivalent annual availability - 85%

***Unit Commitment Parameters***: Coal steam-electric power plants are assumed to operate as base load units with limited dispatch capability. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 50%

Minimum run time - 24 hours

Minimum down time - 12 hours

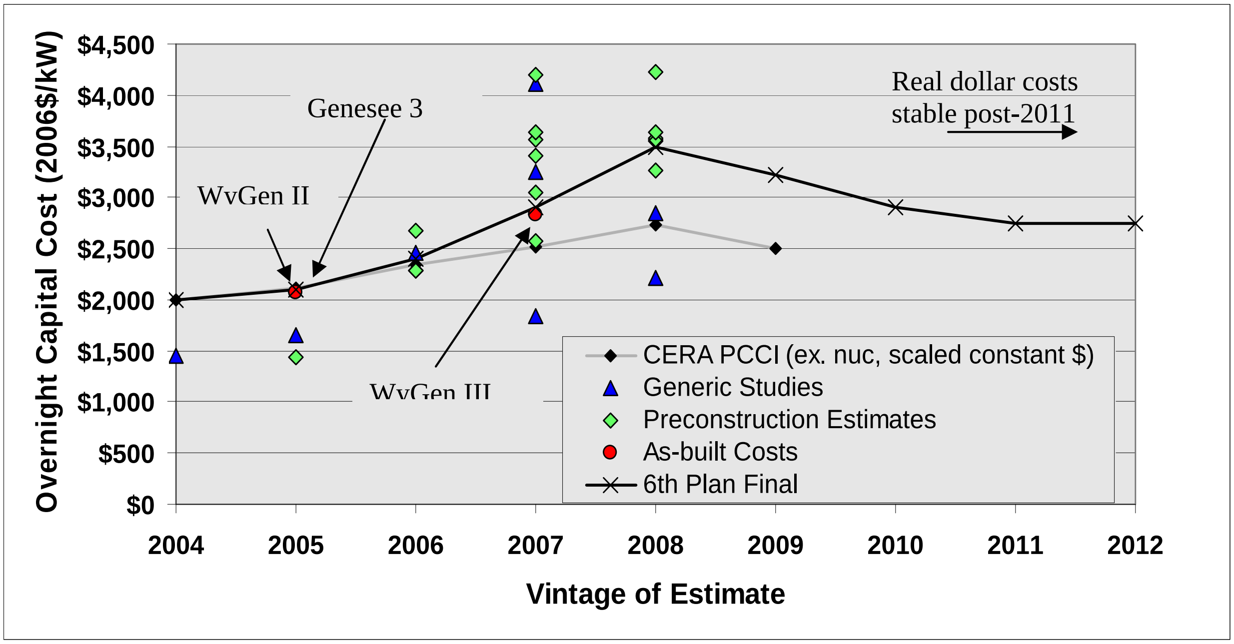
Ramp rate - 30%/hr maximum

***Total Plant Cost:*** The "overnight" total plant cost of the reference pulverized coal-fired plant is estimated to be $3,500/kW installed capacity (2006 dollar values for the 2008 price year; or 2011 service year, assuming costs are fixed at the beginning of the committed construction period). This estimate is based on a sample of three reported as-built plant costs, 15 preconstruction cost estimates, and 8 generic cost estimates, from 2004, or later. These costs were normalized as described in the Capital Cost Analysis subsection of this Appendix and are plotted by vintage in Figure I-20. Also plotted is the CERA (non-nuclear) power plant capital cost index for 2004-09, normalized to real dollar values and scaled to match to 2008 reference cost selected by the Council. A wide range of costs is evident for 2007 and 2008, though the rapid increase in construction costs from 2004 through mid-2008 is well defined. The CERA index, while consistent with the earlier as-built cost examples, does not capture the more rapid escalation embodied in the 2007 and 2008 preconstruction cost estimates. The Sixth Power Plan final estimates follow the 2004 and 2005 CERA and as-built costs closely. The 2006 point corresponds to the cost reported in the 2007 National Engineering Technology Laboratory Report (NETL, 2007), which contains original and detailed cost estimates. The 2007 and 2008 points are heavily influenced by the preconstruction estimates dating from these years, rather than the generic estimates from these years, which appear to be secondary sources.

Total plant cost is forecast to decline from the 2008 high point to market equilibrium conditions by 2011, represented by the average of 2004 and 2008 costs. Total plant costs are assumed to remain constant, on average.

A cost uncertainty range of +20%/- 20% is used for Regional Portfolio Model studies.

**Figure I-20: Overnight total plant costs of coal steam-electric power plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for the representative coal steam-electric power plant are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 36 mo., 3% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 11% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 36 mo., 86% of total plant cost

***Operating and Maintenance Costs:*** The fixed O&M cost for the reference plant are estimated to be $60/kW/yr (exclusive of property tax and insurance). This estimate is based on the fixed O&M costs for a supercritical unit (Case 11) appearing Exhibit 4-35 of NETL, 2007. The cost appearing in NETL was converted to a percentage of the Case 11 capital cost estimate. This percentage (1.8%) was then applied to the Sixth Power Plan price year capital cost described above and the result rounded, yielding $60/MWh.

The variable O&M cost for the reference plant is estimated to $2.75/MWh. This cost is the Case 11 variable O&M cost of NETL, 2007 (in 2006 year dollars), not adjusted for power plant construction cost escalation.

Escalation of fixed operating and maintenance costs is assumed to correspond to the forecast escalation of total plant costs. Variable O&M costs are assumed to vary only with general inflation.

***Economic Life:*** The economic life of a coal-fired steam-electric plant is assumed to be 30 years.

***Technology Variations:*** Cost and heat rate estimates for five technical variations on the reference plant are shown in Table I-26. The values of Table I-26 are based on estimates reported in Table 3-1 of MIT, 2007. The MIT study provides cost and performance estimates for a comprehensive set of coal-fired technologies. Though the costs and heat rate of the supercritical unit of the MIT study differ somewhat from the equivalent values developed for the Sixth Power Plan (the reference units of the MIT study assume use Midwestern bituminous coal, for example), the relative costs and heat rates of the MIT units should be roughly representative of the relative costs and heat rates of units suitable for Northwest conditions. The values of Table I-26 were derived by applying the ratios between the various technologies of Table 3-1 of MIT, 2007 to the reference supercritical values developed for the Sixth Plan.

**Table I-26: Costs and performance of technical variations on the reference pulverized coal-fired steam-electric plant**

| Technology | Heat Rate (Btu/kWh, HHV) | Total Plant Cost ($/kW) | Fixed O&M ($/kW/yr) | Variable O&M ($/MWh) |
|---|---|---|---|---|
| **Subcritical PC** | 10,080 | $3360 | $60 | $2.75 |
| **Supercritical PC (Reference Plant)** | 9000 | $3500 | $60 | $2.75 |
| **Ultra-supercritical PC** | 8010 | $3570 | $60 | $2.75 |
| **Subcritical PC w/90% $CO_2$ Capture** | 13,770 | $5880 | $128 | $5.86 |
| **Supercritical PC w/90% $CO_2$ Capture** | 11,880 | $5635 | $128 | $5.86 |
| **Ultra-supercritical PC w/90% $CO_2$ Capture** | 10,170 | $5495 | $128 | $5.86 |

***Development Potential:*** New pulverized coal-fired power plants would be constructed 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. However, carbon dioxide performance standards in Montana, Oregon and Washington preclude construction of new coal-fired plants without significant reduction (roughly 50 percent) of the carbon dioxide production of conventional subcritical units. Reducing per-megawatt-hour carbon dioxide production from coal-fired plants can be achieved by increased thermal efficiency, fuel switching, and carbon dioxide capture and sequestration. For new construction, increasing the efficiency of combustion is the least cost and logical first step to reducing carbon dioxide production. Ultra-supercritical plants, for example, produce about 80 percent of the carbon dioxide of conventional subcritical units. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production from existing as well as new plants by several percent, but the economics and net impact on carbon dioxide production are case-specific because of coal production and transportation considerations. Co-firing biomass can reduce carbon dioxide production, but the biomass quantities and co-firing percentages are limited. Carbon capture and sequestration will be required to control carbon dioxide releases to the levels needed to achieve proposed greenhouse gas reduction targets if continued reliance on coal is desired. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development and is not expected to be commercially available for a decade, or more. Though legal issues remain, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in the Northwest and though other geologic alternatives are potentially available, including deep saline aquifers and possibly flood basalt sequestration, these remain to be proven and commercialized.

The earliest service years for new plants is assumed to be 2017 for units without $CO_2$ separation and sequestration and 2023 for units with $CO_2$ separation and sequestration.

***Levelized cost summary:*** The estimated levelized lifecycle costs of delivered energy from four coal-fired steam-electric power plant cases are shown in Table I-27. Cases 1, 2 and 3 are plants using subcritical, supercritical and ultra-supercritical technology, respectively, and not provided with $CO_2$ separation. The cost estimates are based on plants sited in eastern Oregon or Washington supplied with Powder River Basin coal by rail. These plants would not comply with current Washington or Oregon $CO_2$ policy. Cases 4, 5 and 6 represent partial repowers of the Colstrip Transmission System with plants equipped with $CO_2$ separation. Separated CO2 would be transported to depleted oil or gas reservoirs, unmineable coal seams or deep saline reservoirs for sequestration. The plants would employ subcritical, supercritical and ultra-supercritical technology, respectively. These plants would comply with current Montana $CO_2$ policy. The cost estimates are based on investor-owned utility financing.

**Table I-27: Levelized Cost of Coal-fired Steam-electric Power Plants**

| Case | Service Year | PlantBusbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| 1. Subcritical (E. OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | $63.46 | $1.00 | $4.53 | $49.59 | $119 |
| | 2025 | $63.62 | $1.00 | $4.57 | $50.82 | $120 |
| | 2030 | $63.72 | $1.01 | $4.59 | $51.26 | $121 |
| 2. Supercritical (E. OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | $63.61 | $1.00 | $4.43 | $44.28 | $113 |
| | 2025 | $63.75 | $1.00 | $4.46 | $45.37 | $115 |
| | 2030 | $63.84 | $1.01 | $4.48 | $45.77 | $115 |
| 3. Ultra-supercritical (E. OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | $62.82 | $1.00 | $4.33 | $39.90 | $108 |
| | 2025 | $62.95 | $1.00 | $4.36 | $40.88 | $109 |
| | 2030 | $63.03 | $1.01 | $4.38 | $41.24 | $110 |
| 4. Subcritical w/CO2 Capture (MT>E. OR/WA via CTS Repower) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | n/av | n/av | n/av | n/av | n/av |
| | 2025 | $103.41 | $1.00 | $17.65 | $41.83 | $164 |
| | 2030 | $103.54 | $1.01 | $17.71 | $42.06 | $164 |
| 5. Supercritical w/CO2 Capture (MT>E. OR/WA via CTS Repower) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | n/av | n/av | n/av | n/av | n/av |
| | 2025 | $98.60 | $1.00 | $16.92 | $36.09 | $153 |
| | 2030 | $98.71 | $1.01 | $16.97 | $36.29 | $153 |
| 6. Ultra-Supercritical w/CO2 Capture (MT>E. OR/WA via CTS Repower) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | n/av | n/av | n/av | n/av | n/av |
| | 2025 | $95.20 | $1.00 | $16.32 | $30.90 | $143 |
| | 2030 | $95.31 | $1.01 | $16.37 | $31.06 | $144 |

## *Coal-fired Gasification Combined-cycle Plants*

First demonstrated in 1670 by the Reverend John Clayton, coal gasification, as applied to electric power generation, allows the application of efficient gas turbine combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility, and lowers carbon dioxide production. Integrated coal gasification combined-cycle plants (IGCCs) also offer the benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration using currently commercial processes, and optional co-production of synthetic natural gas, hydrogen, liquid fuel, or other chemicals. Numerous coal gasification project proposals were announced in North America during the early 2000s, including several in the Northwest. However, estimated costs have escalated significantly, and as designs have been refined, earlier forecasts of greatly improved criteria pollutant emission control capability and plant efficiency for IGCC plants compared to steam-electric coal plants appear optimistic. Current estimates suggest that emission control and efficiency would not be significantly better than supercritical steam electric plants. This appears to have dampened enthusiasm for coal gasification technology. Uncertainties regarding the timing and magnitude of greenhouse gas regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active. One project, the Duke Energy Edwardsport plant, is under construction for 2013 service. The key advantage of IGCC plants remains the commercial technology available for carbon capture.

***Reference Plants:*** Assumptions for two reference IGCC plants were developed; one without and one with carbon capture. These are based, respectively on Cases 3 and 4 of NETL, 2007. The two plants use Conoco-Phillips (CoP) E-Gas oxygen-blown, two-stage, slurry-fed slagging gasifiers. The key advantage of the CoP gasifier from a Northwest perspective is that the commercial-scale CoP gasifiers successfully operated on western subbituminous coal at the 160 MW Dow Chemical coal gasification combined-cycle power plant in Plaquemine, Louisiana. The two-stage CoP design operates at somewhat greater efficiency and reduced oxygen requirement than other gasifier designs and produces only inert solid waste. The high operating temperatures result in a short refractory life, however, and the process produces more methane in the synthesis gas, reducing maximum potential carbon recovery.

The plant without carbon capture (Case 3 of NETL, 2007) includes an air separation unit, a coal preparation section, two gasification trains, syngas coolers, and a gas cleanup section for particulate, mercury and sulfur removal. The clean syngas is heated, humidified, and diluted with nitrogen from the air separation unit and supplied to a combined-cycle section. The combined-cycle section consists of two F-Class gas turbine generators, two heat recovery steam generators and a single steam turbine generator. Evaporative condenser cooling is used. Gross plant capacity is 742 MW and net output is 623 MW. The principal auxiliary loads are the air separation unit and oxygen compressor (55 MW) and the nitrogen dilutent compressor (35 MW).

The configuration of the reference plant with carbon capture (Case 4 of NETL) is similar to the plant without carbon capture with additional stages of syngas hydrolysis to convert the majority of the CO contained in the synthesis gas to $CO_2$. The $CO_2$ is stripped in a Selexol unit and compressed for export. $CO_2$ removal efficiency is 88% (most of the discharged $CO_2$ is produced in the gas turbines from combustion of $CH_4$ (methane) produced directly in the gasifier and thus not strippable. Gross plant capacity is 694 MW and net output is 518 MW. The principal auxiliary loads are the air separation unit and oxygen compressor (72 MW), the nitrogen dilutent compressor (36 MW), the Selexol CO2 stripping unit (15 MW) and the CO2 compressor (26 MW).

***Fuel:*** Two cases are considered. One set of reference plants are assumed to be fuelled by 100% western subbituminous coal. A second set of plants is assumed to be fuelled by a mix of 50% pertroleum coke and 50% western subbituminous coal. Coal price forecasts are described in Chapter 2 and Appendix A. Petroleum coke is assumed to trade at a discount of 80% to western subbituminous coal based on 2008 and 2009 market data.

***Heat Rate:*** The heat rate of the reference plant without carbon capture is 8,680 Btu/kWh and the heat rate of the plant with carbon capture is 10,760 Btu/kWh (NETL, 2007). The higher heat rate of the plant with carbon capture is largely attributable to the auxiliary loads of the carbon capture and compression equipment (the heating value of the carbon is recovered in both cases since the carbon is oxidized). Because the NETL examples are based on Illinois No 6 bituminous coal rather than western low-sulfur sub-bituminous coal, the NETL heat rates may be lower than encountered in practice in the Northwest. The higher moisture content and lower heating value of western subbituminous coal could increase both plant heat rate and plant capital costs. Detailed case studies of coal gasification combined-cycle plants using western subbituminous coal were not available for preparation of the power plan.  Though heat rates for gasification plants using subbituminous coal provided in EPA, 2006, the EPA heat rates for bituminous coal are much lower than equivalent NETL heat rates, having been based on earlier, more optimistic studies.  Moreover, the EPA study assumed use of GE-Texaco gasifiers, a design less suited to western subbituminous coals.  The IGCC heat rates used for this plan should be viewed with caution and will be subject to periodic review.

Plant heat rate is forecast to decline 0.5% annually, consistent with forecast improvements in gas turbine technology.

***Availability Parameters:*** With only two operating IGCC plants in North America, the NERC GADS database does not provide information regarding IGCC availability parameters.  The following estimates are provided in NREL, 2007, as follows:

Scheduled maintenance outages - 30 days/yr

Equivalent forced outage rate - 10%

Mean time to repair - Not available.

Equivalent annual availability - 81%

***Unit Commitment Parameters*:** Coal gasification power plants are assumed to operate as baseload units with limited dispatch capability.  Unit commitment parameters specific to IGCC plants were not located.  Because of the thermal mass of the gasifiers and synthetic gas cooler, the response rate of first-generation gasification plants is likely to be slow.  Nuclear plant commitment parameters were used for interim assumptions until better information becomes available:

Minimum load - 70%

Minimum run time -  120 hours

Minimum down time -  24 hours

Ramp rate - 10%/hr maximum (hot operating conditions)

***Total Plant Cost:*** The total plant cost of the reference plant without carbon capture is estimated to be $3,600/kW.  The equivalent cost of the plant with carbon capture is $4,800/kW (2008 price year).  Sixteen preconstruction estimates and eight generic estimates of IGCC capital costs dating from 2004, or later were located.  No IGCC plants have been constructed since the mid-1990s, so as-built costs were not available.  These costs were normalized as described in the Capital Cost Analysis subsection of this Appendix and are plotted by vintage in Figures I-21 (plants without carbon separation) and I-22 (plants with carbon separation).  Also plotted in each figure is the CERA (non-nuclear) power plant capital cost index for 2004-09, normalized to real dollar values and scaled to match the normalized costs from the NETL report.  Of the available estimates, The NETL estimates of total plant costs appear to be based on the most detailed, relevant and recent cost analysis.  However, the cost of an IGCC plant using western subbituminous coal is likely to be higher than the NETL reference plant costs, based on the use of low moisture, higher Btu Midwestern bituminous coal. The Sixth Plan reference costs were therefore derived by increasing the NETL estimates by 5% and escalating to 2008 at approximately the CERA non-nuclear PCCI rate.

Total plant cost is forecast to decline from 2008 to market equilibrium conditions by 2011, represented by the average of 2004 and 2008 costs. Thereafter, total plant costs are forecast to decline 0.5% annually, consistent with forecast improvements in gas turbine technology.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

**Figure I-21: Total plant costs of coal gasification power plants (without $CO_2$ capture)**

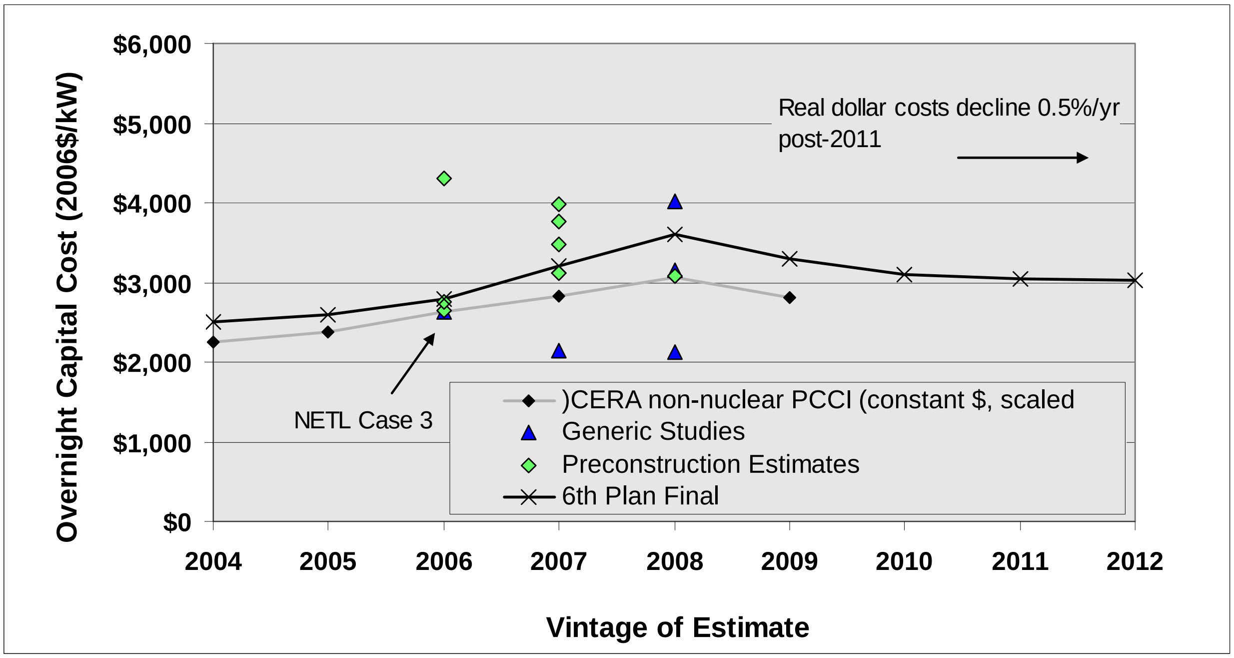
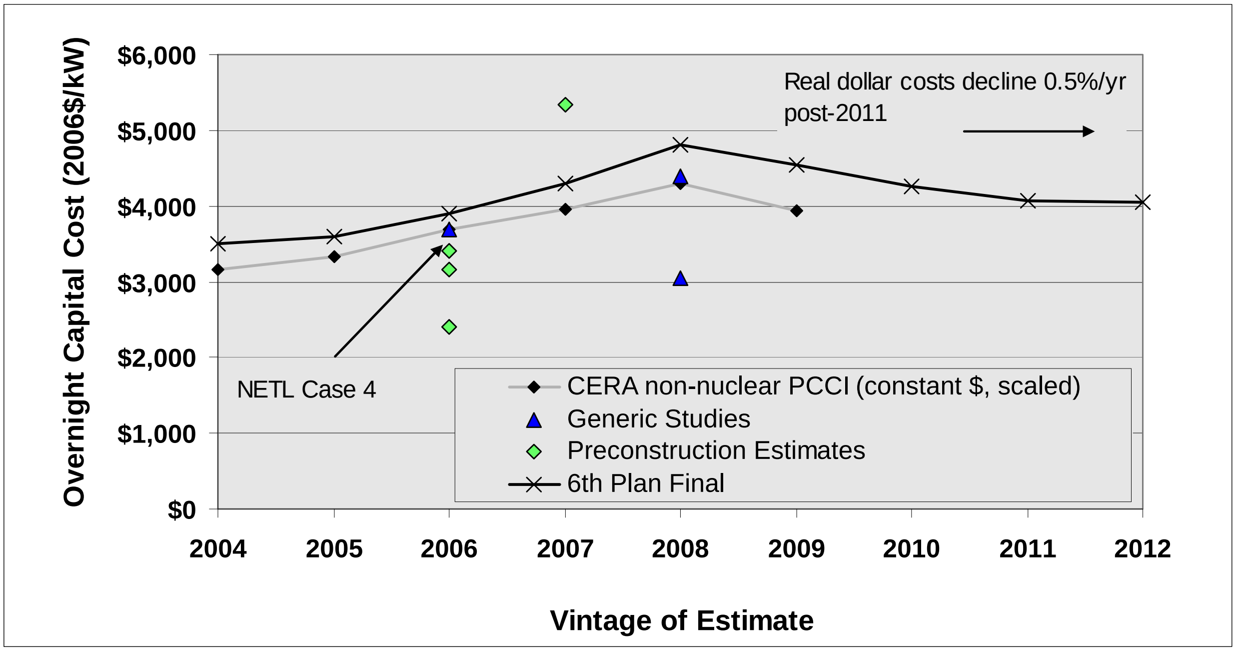


**Figure I-22: Total plant costs of coal gasification power plants (with $CO_2$ capture)**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for both reference IGCC power plants are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 36 mo., 2% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 31% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 36 mo., 67% of total plant cost

***Operating and Maintenance Cost:*** Fixed O&M cost, exclusive of property tax and insurance is $45/kW/yr for the plant without carbon capture and $60/kW/yr for the plant with carbon capture. Variable O&M cost of $6.30/MWh for the plant without carbon capture and $8.50/MWh for the plant with carbon capture. Operating and maintenance costs for the plant with carbon capture include the cost of CO2 compression, but exclude transportation and sequestration costs. The cost of carbon sequestration is described in Carbon Sequestration section of this appendix. O&M costs are based on values appearing in NETL (2007). The NETL O&M costs were increased by the ratio of Sixth Plan total plant cost described above and the normalized total plant cost of NETL plants. Fixed O&M cost is assumed to escalate in real terms with total plant cost. Variable O&M cost is assumed to remain constant in real terms.

***Economic Life:*** The economic life of a coal gasification combined-cycle plant is assumed to be 30 years.

***Development Potential:*** New coal gasification combined-cycle plants would be constructed for the purposes of providing base load power and (optionally) synthetic fuels and chemicals. Coal supplies are adequate to meet any plausible Northwest needs over the period of this plan. However, carbon dioxide performance standards in Montana, Oregon and Washington preclude construction of new coal gasification combined-cycle power plants without capture and sequestration of about 50%, or more of the potential carbon dioxide. While the technology for capturing $CO_2$ from the synthesis gas of a gasification plant is commercially available, Case 2 commercial sequestration facilities are not. As described in the carbon sequestration section, the Council assumes that a commercial sequestration facility would not be available in the Northwest until 2023 at the earliest. The earliest service years for new plants is assumed to be 2017 for units without $CO_2$ separation and sequestration and 2023 for units with $CO_2$ separation and sequestration.

***Levelized cost summary:*** The estimated levelized lifecycle costs of delivered energy from four gasification combined-cycle power plant cases are shown in Table I-28. Case 1 is a plant sited in eastern Oregon or Washington supplied with Powder River Basin coal by rail. Case 2 is a plant sited in western Oregon or Washington. 50% of its fuel would be Powder River Basin coal supplied by rail and 50% of its fuel would be petroleum coke supplied by rail or barge from north Puget Sound refineries. Neither plant would be allowed under current Washington or Oregon $CO_2$ policy. Cases 3 and 4 represent partial repowers of the Colstrip Transmission System with plants equipped with $CO_2$ separation. Separated CO2 would be transported to depleted oil or gas reservoirs, unmineable coal seams or deep saline reservoirs for sequestration. Case 3 would be fuelled with Powder River Basin coal. Case 4 would use a mix of 50% Powder River Basin Coal and 50% petroleum coke from eastern Montana refineries. These plants would comply with current Montana $CO_2$ policy. The cost estimates are based on investor-owned utility financing.

**Table I-28: Levelized Cost of Coal-fired Gasification Combined-cycle Power Plants**

| Case | Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| 1. 100% Coal (E. OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | $71.88 | $1.00 | $4.67 | $40.82 | $118 |
| | 2025 | $70.39 | $1.00 | $4.65 | $40.79 | $117 |
| | 2030 | $68.95 | $1.01 | $4.62 | $40.33 | $115 |
| 2. 50% Coal/50% Pet Coke (W. OR/WA) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | $72.06 | $1.00 | $4.70 | $42.07 | $120 |
| | 2025 | $70.56 | $1.00 | $4.68 | $42.04 | $118 |
| | 2030 | $69.12 | $1.01 | $4.65 | $41.57 | $116 |
| 3. 100% Coal w/CSS (MT > E. OR/WA via CTS Repower) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | n/av | n/av | n/av | n/av | n/av |
| | 2025 | $90.25 | $1.00 | $16.44 | $30.92 | $139 |
| | 2030 | $88.37 | $1.01 | $16.32 | $30.47 | $136 |
| 4. 50% Coal/50% PetCoke w/CSS (MT > E. OR/WA via CTS Repower) | 2010 | n/av | n/av | n/av | n/av | n/av |
| | 2015 | n/av | n/av | n/av | n/av | n/av |
| | 2020 | n/av | n/av | n/av | n/av | n/av |
| | 2025 | $89.24 | $1.00 | $16.44 | $31.87 | $139 |
| | 2030 | $87.37 | $1.01 | $16.31 | $31.41 | $136 |

# *Natural Gas Simple-cycle Aeroderivative Gas Turbine Plant*

Aeroderivative simple-cycle gas turbine power plants are based on jet engines developed for aircraft propulsion and adapted for stationary applications including electric power generation. Aeroderivative gas turbines feature high pressure (compression) ratios and light construction. Higher pressure ratios increase thermal efficiency and produce a more compact unit. Lighter construction improves operational flexibility including black start capability, short run-up, rapid cool-down, and overpower operation. Start times to full load of ten minutes or less allow these machines to provide "virtual" spinning reserve capacity (spinning reserve without the need to be operating).[24] Aeroderivative machines are highly modular and major maintenance can be accomplished by swapping out major components or the entire engine, shortening maintenance outages. Aeroderivative gas turbines are widely used to provide daily peaking capacity and operating reserves and can provide balancing services for variable resource integration. Aeroderivative units with heat recovery steam generators are often used for industrial cogeneration and are occasionally used as the prime mover for combined-cycle power plants. The lighter and more highly stressed components of aeroderivative machines result in higher per-kilowatt initial investment cost than heavy-duty (frame) simple-cycle turbines. Gas turbines require a high fuel supply pressure and fuel gas booster compressors may be required in locations away from natural gas mainlines. Typically electrically-driven, fuel gas booster compressors can consume several percent of the gas turbine generator output, reduce net capacity, and thermal efficiency.

***Reference Plant:*** The reference aeroderivative simple-cycle gas turbine plant consists of twin gas turbine generator sets of 47 MW nominal capacity each. The net "new and clean" base load capacity of the plant under ISO conditions is 92 megawatts. This is based on the nominal capacity of a General Electric LM6000PD Sprint™ (Gas Turbine World, 2007), derated 3.1% for inlet, exhaust, auxiliary load, and main transformer losses. The new and clean heat rate is degraded a further 2.5% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 90 MW (ISO conditions). The gas turbine generators are enclosed for weather protection and acoustic control, and are provided with inlet air filters and exhaust silencers. The plant also includes an injection water treatment system, lube oil, starting, fuel forwarding, and control systems; a control building, step-up transformers and a switchyard. Dry low-NOx combustors and selective catalytic reduction are used for NOx control and an oxidation catalyst for CO and VOC control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

***Fuel:*** Natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

***Heat Rate:*** The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 9,300 Btu/kWh[25]. This is based on the nominal lower heating value heat rate of a General Electric LM6000PD Sprint™ (water spray injection intercooling) (Gas Turbine World, 2007), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load and

[24] However, though physically capable of achieving full load in less than 10 minutes, emission limits are reported to have precluded the use of non-operating aeroderivative turbines for spinning reserves (Keyspan, 2007).

[25] Fuel gas compresssion, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

transformer losses. The new and clean heat rate degraded a further 0.8% for maintenance-adjusted lifecycle aging effects to obtain a lifecycle average full load heat rate of 9,370 Btu/kWh.

***Availability parameters:*** Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all gas turbines, as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 88 hours

Equivalent annual availability - 91%

***Unit Commitment Parameters*:** Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normall provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{\underline{xmp}®}$ Electric Power Market Model are as follows:

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - Cold start to full load in 10 minutes

***Total Plant Cost:*** The overnight total plant cost of the reference plant is estimated to be $1,050/kW[26] in 2006 dollars for the 2008 price year. The estimate is based on a sample of 4 reported as-built plant costs, 10 preconstruction cost estimates, and 5 generic cost estimates (including one range estimate). The sample costs were normalized as described in the Capital Cost Analysis section of this appendix. Owner's costs, where not included in the estimate, were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 130% of multiple-unit plants. The resulting normalized costs are shown in Figure I-23.

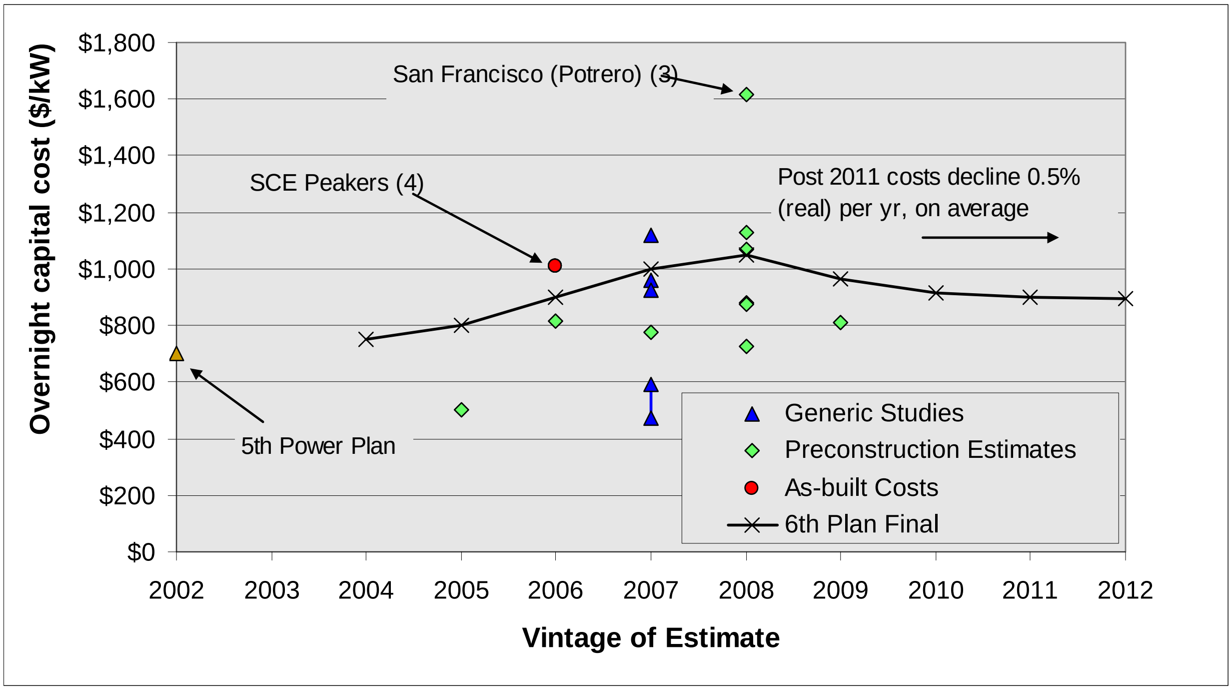
The normalized costs show evidence of the 2004 to 2008 escalation of power plant costs, but are scattered in 2007 and 2008. This may result from variation in plant designs or site conditions or imperfect information for normalization. The cost of the San Francisco Potrero plants is a noticeable high side outlier. Because of the controversial, highly urbanized location, extended schedule delays and challenging air quality constraints, this plant is unlikely to be representative of future Northwest projects. Because of the lack of usable project data for 2002 - 2004, the Sixth Plan cost curve is based off the 2002 vintage Fifth Power Plan generic estimates for aeroderivative gas turbines. The curve escalates to the 2008 peak, running on the high side the majority of the 2005 through 2008 samples and somewhat below the Southern California Edison projects. Total plant cost is forecast to decline from the 2008 high to market equilibrium

[26] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $1025/kW.

conditions by 2011, represented by the average of estimated 2004 and 2008 cost. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

A cost uncertainty range of +30%/-30% is used for Regional Portfolio Model studies.

**Figure I-23: Total plant costs of aeroderivative gas turbine power plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for aeroderivative gas turbine plants are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 18 mo., 5% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 9 mo., 50% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 6 mo., 45% of total plant cost

The overall duration of the development period and construction periods remains at the value used for the Fifth Power Plan. However, the Early Construction period is shorted from 12 to 9 months and the Committed Construction Period extended by 3 months. Level cash flows are assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

***Operating and Maintenance Cost:*** Fixed O&M cost is estimated to be $13/kW/yr. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable

O&M is estimated to be $4.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, SCR catalyst replacement, ammonia, water and other consumables. The O&M estimates are based on the NERA "Lower Hudson Valley" LM6000 case (Table A-3 of NERA, 2007), excluding site leasing costs, property tax and insurance. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

***Economic Life:*** The economic life of an aeroderivative gas turbine plant is assumed to be 30 years.

***Developable Potential:*** No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure or air quality constraints.

***Levelized cost summary:*** The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle aeroderivative gas turbine power plant are shown in Table I-29. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

Table I-29: Levelized Cost of Natural Gas Simple-cycle Aeroderivative Gas Turbine Power Plants

| Service Year | Capacity Cost ($/kW/yr) | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| 2010 | $166 | $94.29 | $0.98 | $6.41 | $17.81 | $119 |
| 2015 | $164 | $98.92 | $0.99 | $6.68 | $22.91 | $130 |
| 2020 | $162 | $100.65 | $1.00 | $6.76 | $24.08 | $132 |
| 2025 | $159 | $100.98 | $1.00 | $6.78 | $24.06 | $133 |
| 2030 | $157 | $100.94 | $1.01 | $6.80 | $24.03 | $133 |

## *Natural Gas Simple-cycle Heavy-duty (Frame) Gas Turbine Plant*

Heavy-duty (also called Frame or Industrial) gas turbines are designed specifically for stationary installations. Weight and physical size are not as constraining as they are for aeroderivative units. Heavy-duty machines are available in much larger sizes than aeroderivative units and are designed for long life and reliability. Pressure (compression) ratios are lower for aeroderivative machines, resulting in less demanding design conditions, but produce a bulkier, somewhat less efficient engine. More robust construction improves durability, but constrains operational flexibility. Start time to full load typically exceeds ten minutes so heavy-duty machines must be operating to provide spinning reserve capacity. Major maintenance is accomplished on site in contrast to the component swap out common for aeroderivative units. Because of economies of scale and less demanding design conditions, heavy duty machines cost less per-kilowatt capacity than aeroderivative units. Heavy-duty simple-cycle gas turbines are used to provide daily and seasonal peaking capacity, especially where infrequent, but extended operation may be required.

They are also used in plants where eventual conversion to combined-cycle configuration is planned. Like aeroderivative units, heavy-duty gas turbines require a high fuel supply pressure and fuel gas booster compressors may be needed in locations away from natural gas mainlines. The higher exhaust gas temperatures of some frame machines preclude the use of SCR for NOx and CO control. This may limit site availability and operating hours.

***Reference Plant:*** The reference heavy-duty simple-cycle gas turbine plant consists of a single gas turbine generator set of 85 MW nominal capacity. The net "new and clean" capacity of the plant under ISO conditions is 83 megawatts. This is based on the nominal capacity of a General Electric MS7001EA (Gas Turbine World, 2007), derated 3.1% for inlet, exhaust, auxiliary load and main transformer losses. The new and clean heat rate is degraded a further 2.5% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 81 MW (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers. The plant also includes lube oil, starting, fuel forwarding, and control systems; a control building, step-up transformers and a switchyard. Dry low-NOx combustors are used for NOx emissions control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

***Fuel:*** Natural gas is supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

***Heat Rate:*** The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 11,870 Btu/kWh. This is based on the nominal lower heating value heat rate reported for a General Electric MS7001EA in Gas Turbine World (2007), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle average higher heating value full load heat rate is estimated to be 11,960 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.8% for maintenance-adjusted lifecycle aging effects[27].

***Availability parameters:*** Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data, as described for aeroderivative gas turbine plants.

***Unit Commitment Parameters*:** Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{\underline{xmp}®}$ Electric Power Market Model, as described for aeroderivative gas turbine plants.

***Total Plant Cost:*** The overnight total plant cost of the reference plant is estimated to be $610/kW[28] in 2006 dollars for the 2008 price year. This estimate is based on a sample of 3 reported as-built plant costs, 7 preconstruction cost estimates (including one range estimate), and 6 generic cost estimates (including two range estimates). The sample costs were normalized as

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[27] Fuel gas compression, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

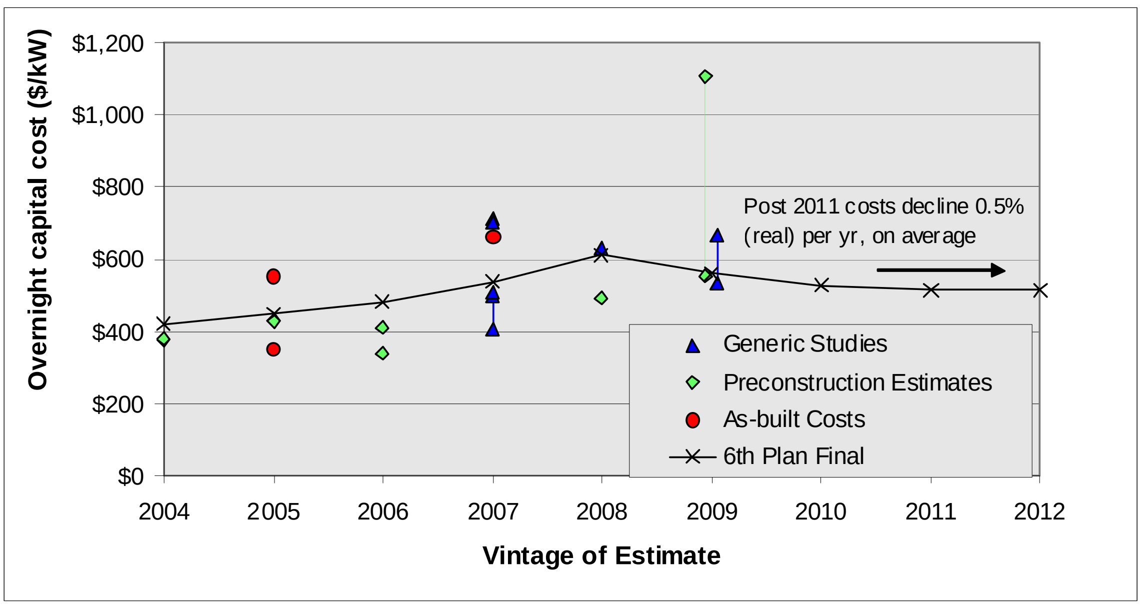
[28] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $595/kW.

described in the Capital Cost Analysis section of this appendix. Owner's costs, where not included in the estimate, were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 130% of multiple-unit plants. The examples included larger F-class as well as E-class machines because of the limited number of Frame E examples. Though unit scale economies were expected, this was not reflected in the data. Because normalized E-class examples lie above and below the curve chosen for the Sixth Plan, no unit scale adjustment was made. The resulting normalized costs are shown in Figure I-24. The range estimates are represented by connected point pairs in the Figure.

Except for the 2009 Pastoria range estimate, the samples are reasonably clustered for each year and clearly reflect the escalation of power plant costs from 2004 to 2008. The Pastoria estimate appears to assume that 2004 to 2008 rates of escalation would continue in 2009. The Sixth Power Plan cost curve is placed within all 2004 through 2008 samples. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by 2011, assumed to be the average of estimated 2004 and 2008 costs. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

A cost uncertainty range of +25%/- 25% is used for Regional Portfolio Model studies.

**Figure I-24: Total plant costs of heavy-duty (frame) gas turbine power plants**




***Development and Construction Schedule:*** See discussion under Aeroderivative Simple-cycle Gas Turbine Plant

***Economic Life:*** The economic life of a heavy-duty simple-cycle gas turbine power plant is assumed to be 30 years.

***Operating and Maintenance Cost:*** Fixed O&M cost is estimated to be $11/kW/yr[29]. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $1.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, and consumables. The O&M estimates are based on the average of the NERA "Syracuse" and "Albany" GE7FA cases (Table A-3 of NERA, 2007), excluding site leasing costs, property tax, and insurance. The NERA fixed costs were adjusted by the ratio of GE7FA capacity to GE7EA capacity to account for expected unit scale economies, and further increased by 30% to normalize to a single unit installation. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

***Developable Potential:*** No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure or air quality constraints. Siting opportunities may be limited to non-sensitive attainment air quality areas because of the lack of SCR control of NOx and CO emissions.

***Levelized cost summary:*** The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle heavy-duty gas turbine power plant are shown in Table I-30. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

**Table I-30: Levelized Cost of Natural Gas Simple-cycle Heavy-duty (Frame) Gas Turbine Power Plants**

| Service Year | Capacity Cost ($/kW/yr) | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh | Transmission And Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| 2010 | $132 | $97.76 | $0.98 | $6.57 | $22.74 | $128 |
| 2015 | $134 | $104.93 | $0.99 | $6.92 | $29.24 | $142 |
| 2020 | $134 | $107.55 | $1.00 | $7.02 | $30.73 | $146 |
| 2025 | $132 | $108.36 | $1.00 | $7.05 | $30.71 | $147 |
| 2030 | $131 | $108.71 | $1.01 | $7.08 | $30.67 | $147 |

## *Natural Gas Simple-cycle Intercooled Gas Turbine Plant*

Combustion air compression consumes about two-thirds of the total power produced by a gas turbine engine. This energy consumption can be reduced by intercooling - cooling the compressed air at intermediate stages of compression. Intercooling improves thermal efficiency by reducing the energy needed for air compression and increases power output for a given size

29 An earlier fixed O&M estimate of $4/kW/yr, not normalized for the unit scale of the 7EA machine, or to a single unit plant, was used for portfolio model studies. The $11/kW/yr value increases the fixed cost of the reference plant by 3% from $128/kW/yr to $134/kW/yr. The levelized cost of energy at a 10% capacity factor, typical of a peaking unit would increase by 2% from $255/MWh to $261/MWh (IOU financing, 2015 service year).

turbine by increasing density of air flowing through the high pressure stages of the compressor and the power turbine. Intercooling can be accomplished by direct injection of water into the compressed air stream or by routing the compressed air through an external air cooler. Turbine designs such as the aeroderivative General Electric LM6000 Sprint™ use direct water spray injection. The sole commercial gas turbine using external intercooling is the General Electric LMS100™. The LMS100, introduced in 2004, is called a hybrid intercooled turbine because it uses both aeroderivative and heavy-duty gas turbine components and design practices. The combination of external intercooling and use of lightweight aeroderivative components improves both simple-cycle thermal efficiency and operating flexibility (flatter heat rate curve, fast ramping, fast cold start, and reduced cycling maintenance penalty). The external air cooler and cooling system add to the complexity and cost of the plant. Water consumption may be reduced compared to a spray-injected intercooled machine, especially if dry mechanical draft cooling is used to chill the intercooler.

***Reference Plant:*** The reference intercooled simple-cycle gas turbine plant consists of a single gas turbine generator set of 99 MW nominal capacity, an external intercooler, an evaporative mechanical draft cooling system for the intercooler, lube oil, fuel forwarding and other ancillary equipment, a control building, and switchyard. Cost and performance characteristics are based on the General Electric LMS100PB (dry low-NOx combustors). Auxiliary loads for external intercooler technology will be greater than a conventional simple-cycle unit and the net "new and clean" capacity of the plant under ISO conditions is 96 megawatts. The new and clean heat rate is degraded a further 2.2% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 94 MW (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers. The plant also includes an outboard intercooler, a mechanical draft evaporative intercooler cooling system, a makeup cooling water treatment plant; lube oil, starting, fuel forwarding, and control systems; a control building and switchyard. Dry low-NOx combustors are used for NOx emissions control. The plant is assumed to be located near a natural gas mainline with sufficient pressure for operation without fuel gas booster compression.

***Fuel:*** Natural gas is supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

***Heat Rate:*** The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 8,810 Btu/kWh. This is based on the nominal lower heating value heat rate reported for a General Electric LMS100PB in Gas Turbine World (2009), converted to higher heating value and derated 3.1% for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle average higher heating value full load heat rate is estimated to be 8,870 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.8% for maintenance-adjusted lifecycle aging effects[30].

***Availability parameters:*** Because the first LMS100 entered service in 2006, long-term availability information is not available. Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for all gas turbines, and are as follows:

[30] Fuel gas compresssion, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 88 hours

Equivalent annual availability - 91%

***Unit Commitment Parameters*:** Gas turbines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - Cold start to full load in 10 minutes

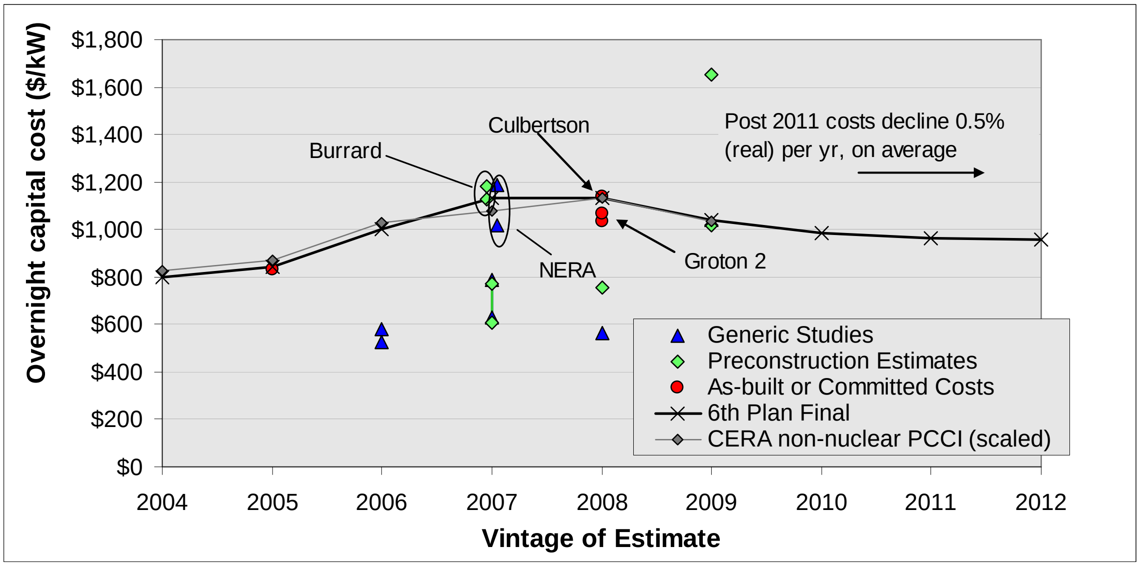
***Total Plant Cost:*** The overnight total plant cost of the reference plant is estimated to be $1,130/kW[31] in 2006 dollars for the 2008 price year. This estimate is based on a sample of 1 reported as-built plant cost, 3 "as-committed" cost estimates, 7 preconstruction cost estimates (including one range estimate), and 5 generic cost estimates including two range estimates. The sample costs were normalized as described in the Capital Cost Analysis section of this appendix. Owner's costs, where not included in the estimate were assumed to represent 12% of total plant costs. Single-unit plants were assumed to cost 30% more than multiple-unit plants (approximation from NERA, 2007, Figure II-3). The resulting normalized costs are shown in Figure I-25. The range estimates are represented by connected points in the figure.

The normalized estimates are scattered and the 2004 - 2008 escalation in construction costs is not clearly evident unless the two 2009 preconstruction estimates are considered. The high-lying 2009 preconstruction estimate may date prior to the peaking of construction costs in mid-2008. The recent introduction of the LMS100 further complicates estimating a 2008 price year and a market equilibrium cost. No estimates are available prior to 2005, and the 2005 estimate is the as-built cost of Groton 1, the first commercial LMS100. The cost of Groton 1 may not be representative. First-of-a-kind problems may have increased construction costs, while on the other hand, the manufacturer may have offered discount pricing, in-kind services, or special warranties to help place the first unit in the field. The curve chosen for the Sixth Power Plan is strongly influenced by the upper NERA (SCR) case (NERA, 2007), Groton 2, Burrard Replacement and Culbertson data points and the CERA non-nuclear PCCI (www.ihsindexes.com). These plant data are well-documented, reasonably representative of the reference unit and follow completion and initial operation of Groten 1 by two or more years. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by

[31] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.5% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be about $995/kW.

2011. Equilibrium conditions were assumed to be the average of estimated 2004 and 2008 price year costs. Following 2011, costs are assumed to decline, on average at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

**Figure I-25: Total plant costs of intercooled gas turbine power plants**




***Development and Construction Schedule:*** See discussion under Aeroderivative Simple-cycle Gas Turbine Plant

***Economic Life:*** The economic life of an intercooled hybrid simple-cycle gas turbine power plant is assumed to be 30 years.

***Operating and Maintenance Cost:*** Fixed O&M cost is estimated to be $8/kW/yr. Fixed O&M includes operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $5.00/MWh. Variable O&M includes operating hour or startup-based major maintenance labor and materials, unscheduled maintenance, SCR catalyst replacement, ammonia, water, and other consumables. The O&M estimates are based on the NERA "Lower Hudson Valley" LMS100 case (Table A-3 of NERA, 2007), excluding site leasing costs, property tax and insurance. Fixed costs are increased by 30% to normalize to a single unit installation. Fixed O&M costs are assumed to escalate in real terms with total plant costs. Variable O&M costs are assumed to remain constant in real terms.

***Developable Potential:*** No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that should not be constrained by gas supply, other infrastructure, or air quality constraints.

***Levelized cost summary:*** The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas simple-cycle intercooled gas turbine power plant are shown in Table I-31. The cost estimates are based on investor-owned utility financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

**Table I-31: Levelized Cost of Natural Gas Simple-cycle Intercooled Gas Turbine Power Plants**

| Service Year | Capacity Cost ($/kW/yr) | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| **2010** | $168 | $92.75 | $0.98 | $6.37 | $16.86 | $117 |
| **2015** | $164 | $96.83 | $0.99 | $6.62 | $21.69 | $126 |
| **2020** | $162 | $98.42 | $1.00 | $6.69 | $22.79 | $129 |
| **2025** | $159 | $98.68 | $1.00 | $6.71 | $22.78 | $129 |
| **2030** | $157 | $98.60 | $1.01 | $6.73 | $22.75 | $129 |

## *Natural Gas Reciprocating Engine Generator Plant*

Reciprocating-engine generators (also known as internal combustion engines, ICs or gen-sets) consist of a compression or spark-ignition reciprocating engine driving a generator. Individual units are typically frame mounted and supplied as modular units. Unit sizes for power system applications range from about one to 17 megawatts. Reciprocating generators are used for small isolated power systems, emergency capacity at sites susceptible to transmission outages, and to provide emergency power and black start capacity at larger power plants. Other applications include units modified to operate on biogas from landfills or anaerobic digestion of waste biomass, industrial cogeneration, and mobile units for emergency service. Reciprocating units also provide backup power for hospitals, elevators and emergency lighting in high-occupancy buildings, and other critical loads. Except for biogas units, these applications typically use light fuel oil stored on site.

With improvements in emission control and thermal efficiency, reciprocating-engine generators increasingly have been incorporated into natural-gas fuelled multi-unit power generation stations for main grid applications. The high efficiency, flat heat rate curves and rapid response of contemporary reciprocating-engine generator sets make these plants especially suitable for peaking and intermediate load service and for the provision of balancing and other ancillary services. Because of lower fuel supply pressure requirements, fuel gas booster compressors are usually not required for commercial gas supplies. Lower fuel supply pressure requirements afford greater siting flexibility. A further advantage of reciprocating units, is that compared to gas turbines, power output falls off more slowly with increasing elevation and ambient temperature. Finally, a reciprocating engine plant comprised of several small units can be more efficient at part-load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and load the remaining units at or near peak efficiency. On the other hand, lube oil consumption of reciprocating engines is high, leading to somewhat greater variable O&M cost than a comparable gas turbine.

***Reference Plant:*** The reference reciprocating engine plant consists of twelve 8.25 MW capacity engine-generators comprising a plant of approximately 100 MW nominal capacity. The plant would normally include a generator and control building, reciprocating engine-generator units, fuel, electrical and control and instrumentation systems, closed-cycle (radiator) cooling, and a switchyard. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

***Heat Rate:*** The full load, higher heating value heat rate under "new and clean" conditions is estimated to be 8,800 Btu/kWh. This is based on the guaranteed-to-grid heat rate for a plant employing Wartsila 20V34 engines. The lifecycle average higher heating value full load heat rate is estimated to be 8,850 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 0.6% for maintenance-adjusted lifecycle aging effects.

***Availability parameters:*** Availability parameters are based on 2004 - 2008 NERC Generating Availability Data System (GADS) data for diesel units, as follows:

Scheduled maintenance outages - 7 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 56 hours (per unit)

Equivalent annual availability - 93%

The GADS statistics for reciprocating units are from old units, on average, and may be low for contemporary plants.

***Unit Commitment Parameters*****:** Reciprocating engines are assumed to operate as dispatchable units. In the Northwest, these plants would normally provide capacity reserves. As such, they could serve peak loads, provide incremental and decremental load following and wind integration service and provide seasonal backup for low water years. Unit commitment parameters (used in the AURORA$^{\underline{xmp}®}$ Electric Power Market Model) are as follows:

Minimum load - 40% (all engines running) (Kirby, 2007). A 100 MW plant could provide 30 MW up regulation and 30 MW down regulation.

Minimum run time - 1 hour

Minimum down time - 1 hour

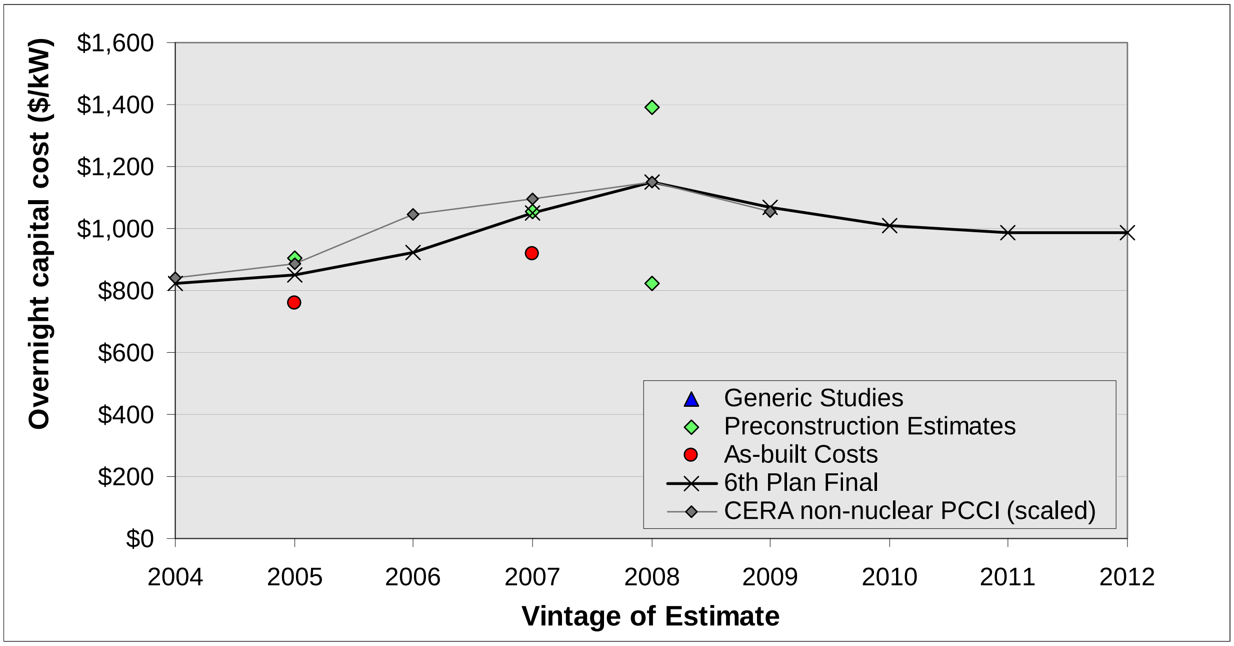
Ramp rate, warm start to full load - Less than 10 minutes (Kirby, 2007). Virtual spinning reserve under warm start conditions.

***Total Plant Cost:*** The overnight total plant cost of the reference reciprocating engine plant is estimated to be $1,150/kW installed capacity (2008 price year). This estimate is based on a sample of two reported as-built plant costs and 4 preconstruction estimates from 2004, or later. No recent generic estimates of reciprocating engine-generator plant costs were located. Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-26. A wide range of costs is evident for 2007 and

2008, though the general increase in power plant construction costs from 2004 through mid-2008 is well defined. The Sixth Plan cost estimate follows the shape of the CERA PPCCI curve and is positioned midway between the sample values.

Total plant cost is forecast to decline from the 2008 high point to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Total plant costs are assumed to remain constant in real terms thereafter.

**Figure I-26: Published and forecast capital costs of reciprocating engine plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for reciprocating engine plant are the same as assumed for gas turbine plants, as follows:

> **Development** (Site acquisition, permitting, preliminary engineering, interconnection agreement) - 18 mo., 5% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction) - 9 mo., 50% of total plant cost
>
> **Committed Construction** (Major equipment installation, commissioning) - 6 mo., 45% of total plant cost

***Fuel Price:*** Fuel price forecasts are described in Chapter 2 and Appendix A.

***Operating and Maintenance Cost:*** Fixed O&M cost, excluding property tax and insurance is estimated to be $13/kW/yr. Fixed O&M includes operating labor and routine maintenance labor and materials, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction. Variable O&M is estimated to be $10.00/MWh. Variable O&M includes operating hour-based major maintenance labor and materials, unscheduled maintenance warranty, SCR catalyst replacement, ammonia, lube oil and other consumables. Variable O&M is assumed to remain constant in real terms through the life of the plant.

***Economic Life:*** The economic life of a reciprocating engine plant is assumed to be 30 years; limited by the expected operating life of major equipment.

***Developable Potential:*** In the Northwest, reciprocating engine plants will likely compete with simple and combined-cycle gas turbine technology for serving intermediate and peak loads and to provide regulation and load-following and other ancillary services. The recommended (least risk) resource portfolio contains a maximum of 1,000 MW of new combined-cycle and simple-cycle gas turbine capacity. A portion of this capacity may be served by reciprocating engine plants. This amount is unlikely to be constrained by gas supply or other infrastructure or air quality constraints.

***Levelized cost summary:*** The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from natural gas reciprocating engine generator power plants are shown in Table I-32. The cost estimates are based on investor-owned utility financing financing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission. Energy costs are illustrative for 46% capacity factor (4000 hours per year) operation.

**Table I-32: Levelized Cost of Natural Gas Reciprocating Engine Generator Power Plants**

| Service Year | Capacity Cost ($/kW/yr) | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|
| 2010 | $180 | $100.68 | $0.98 | $6.52 | $16.91 | $125 |
| 2015 | $172 | $105.39 | $0.99 | $6.80 | $22.30 | $135 |
| 2020 | $171 | $108.79 | $1.00 | $6.91 | $24.03 | $141 |
| 2025 | $170 | $110.92 | $1.00 | $6.98 | $24.62 | $144 |
| 2030 | $168 | $111.63 | $1.01 | $7.02 | $24.84 | $144 |

## *Natural Gas Combined-Cycle Plant*

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator. Capture of the energy of the gas turbine exhaust increases the overall thermal efficiency of a combined-cycle plant compared to a simple-cycle gas turbine generator. The reference combined-cycle unit, for example, has a base load efficiency of 48 percent compared to a full-load efficiency of 38 percent for the reference hybrid intercooled gas turbine. Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production) by extracting steam at the needed pressure from the heat-recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). The resulting capacity increment operates at somewhat lower electrical efficiency than the base plant and is usually reserved for peaking operation, the incremental efficiency, however, is comparable to that of simple-cycle gas turbines. Because they often operate at or near market clearing prices, combined-cycle plants can be an economical source of system balancing reserves. With high reliability, high efficiency, low capital cost, short lead-time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

***Reference Plant:*** The reference plant is a single train (1x1) natural gas-fired combined-cycle plant consisting of a "G-class" gas turbine generator, a fired heat recovery steam generator and a steam turbine generator. The "new and clean" net base load capacity under ISO conditions is 395 megawatts with 25 megawatts of peaking power augmentation. The net baseload capacity is based on the nominal capacity of a 1x1 Mitsubishi 501G combined-cycle unit (Gas Turbine World, 2009), derated 0.9% for SCR and main transformer losses. The new and clean heat rate is degraded a further 2.7% for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 385 MW. 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.

***Fuel:*** Natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Fuel price forecasts are described in Chapter 2 and Appendix A.

***Heat Rate:*** The higher heating value heat rate at full baseload under "new and clean" conditions is estimated to be 6,790 Btu/kWh. This is the reported heat rate for the Port Westward plant (Mitsubishi MHI 501G). The lifecycle average higher heating value heat rate at full baseload is estimated to be 6,930 Btu/kWh, HHV. This is based on the new and clean heat rate degraded 2.1% for maintenance-adjusted lifecycle aging effects[32]. The incremental heat rate of supplemental (duct fired) capacity is estimated to be 9,500 Btu/kWh (Fifth Plan assumption).[33]

***Availability parameters:*** Availability parameters are based on 2004 - 2008 NERC GADS data for all combined-cycle plants, and are as follows:

Scheduled maintenance outages - 21 days/yr

Equivalent forced outage rate - 6%

Mean time to repair - 32 hours

Equivalent annual availability - 89%

***Unit Commitment Parameters*:** Combined-cycle gas turbines are assumed to operate as dispatchable units. In the Northwest, combined-cycle plants normally provide firm capacity, and intermediate and baseload energy production. The baseload section of these plants can be engineered to provide incremental and decremental load following and wind integration service. The duct firing capability provides additional capacity reserves. Duct firing can serve peak

[32] Fuel gas compression, if needed, will further increase net heat rate, as will extended partial load operation. Startup inefficiencies will also increase heat rate, though the significance of the impact will depend on startup frequency.

[33] A base load heat rate of 7110 Btu/kWh for new combined-cycle plants was estimated using an erroneous spreadsheet early in the development of the Sixth Power Plan. This value was carried forward to subsequent wholesale price forecasts and Regional Portfolio Model studies for the final plan. A heat rate of 7110 Btu/kWh would increase the levelized cost of power from a combined-cycle unit operated in baseload mode (80% capacity factor) by 2% (less than $2/MWh).

loads, provide incremental and decremental load following and wind integration service, and seasonal backup for low water years. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 70% of base load capacity

Minimum run time - 6 hours

Minimum down time - 12 hours

Ramp rate - greater than 100%/hr (hot operating conditions)

***Fuel Price:*** Fuel price forecasts are described in Chapter 2 and Appendix A.

***Economic Life:*** The economic life of a combined-cycle plant is assumed to be 30 years.

***Total Plant Cost:*** The overnight total plant cost of the reference plant is estimated to be $1,120/kW[34] in 2006 dollars for the 2008 price year. This estimate is based on an estimated cost of base load capacity of $1,160/kW and an estimated cost of supplementary (fired HSRG) capacity of $465/kW. These estimates were derived from 6 reported as-built plant costs, 16 preconstruction cost estimates (one with low and high bound estimates), and 4 generic cost estimates (one including low and high bound costs) from 2004, or later. The sample costs were normalized as described in the Capital Cost Analysis section of this Appendix to represent a base a single-train (1x1) plant with evaporative cooling. For normalization to base load-only cost, supplementary firing capacity was assumed to cost 40% of base load capacity. Single-train plants were assumed to cost 10% more than plants using multiple gas turbine configurations and owner's costs were assumed to represent 20% of total plant costs. The resulting normalized costs are shown in Figure I-27.

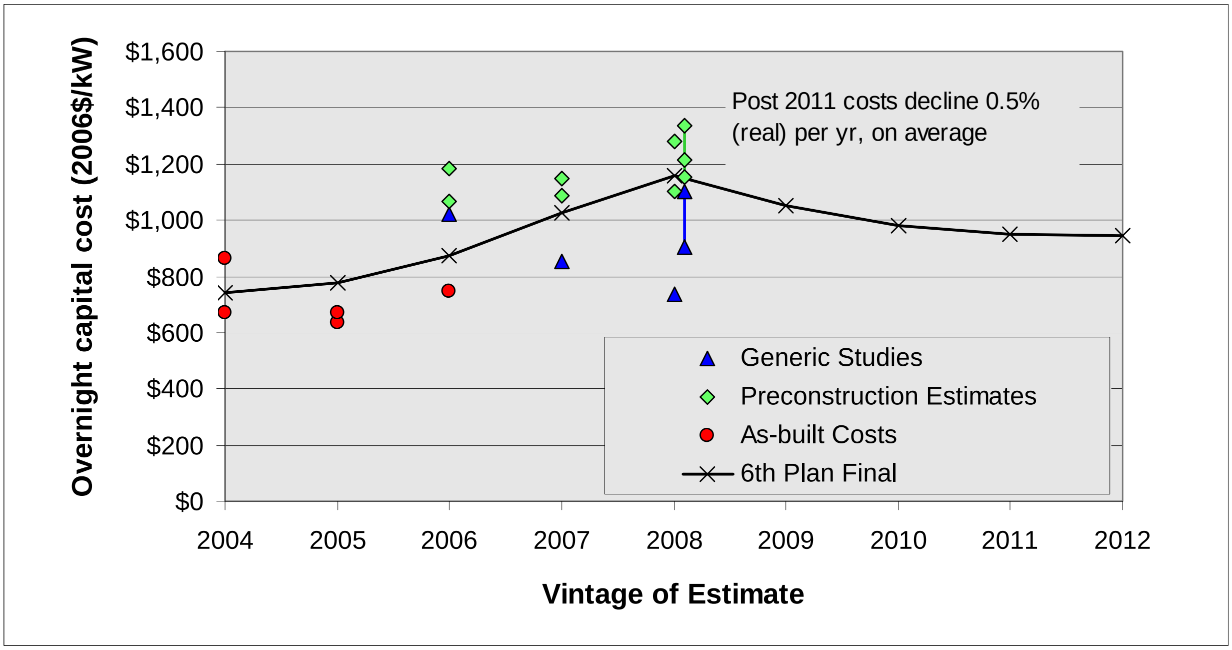
The averages of the two 2004 as-built examples and the intersection of the range of preconstruction and generic cost estimates establish the 2004 and 2008 points of the Sixth Plan cost curve. The fairing of the curve between these years is influenced by the 2005 and 2006 as-built cost examples and the 2007 preconstruction example. Total plant cost is forecast to decline from the 2008 high to market equilibrium conditions by 2011, represented by the average of estimated 2004 and 2008 cost. Thereafter, costs are assumed to decline at 0.5% per year, reflecting a 5% learning rate for gas turbine technology.

The total plant cost for the reference plant is the sum of the capacity-weighted base load and supplementary firing capacity costs.

A cost uncertainty range of +30%/- 30% was used for Regional Portfolio Model studies.

[34] "Lifecycle average" capacity basis. The average capacity over the life of a gas turbine-based power plant is estimated to be 97.3% of new and clean capacity. The total plant cost on the basis of new and clean capacity would be $1090/kW.

**Figure I-27: Total plant costs of combined-cycle power plants**




***Development and Construction Schedule, Cash Flows:*** The development and construction schedule and cash flow assumptions for the reference combined-cycle plant are as follows:

> **Development** (Site acquisition, environmental assessment, permitting, preliminary engineering, interconnection agreement, EPC selection) - 24 mo., 4% of total plant cost
>
> **Early Construction** (Final engineering, equipment order, site preparation, interconnection, infrastructure construction, foundations) - 12 mo., 42% of total plant cost
>
> **Committed Construction** (Major equipment delivery through commissioning) - 18 mo., 54% of total plant cost

Development and Early Construction schedules are the values used in the Fifth Power Plan. The overall construction period was extended from 24 to 30 months at the recommendation of the Council's Generating Resources Advisory Committee (GRAC) to reflect recent construction experience. Level cash flows are assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

***Operating and Maintenance Cost:*** Fixed O&M cost, exclusive of property tax and insurance is $14/kW/yr. Variable O&M is $1.70/MWh. These values are based on NETL (2007), escalated in proportion to the difference in the normalized combined-cycle capital cost of NETL (2007) and the Sixth Plan total plant cost described above. Fixed O&M cost is assumed to escalate in real terms with total plant cost. Variable O&M is assumed to remain constant in real terms.

***Economic Life:*** The economic life of a combined-cycle plant is assumed to be 30 years.

***Development Potential:*** No constraints were initially placed on the cumulative development potential for combined-cycle gas turbine plants pending initial portfolio model results. The portfolio for the Carbon Risk scenario includes a maximum of 830 MW (two units) of new combined-cycle gas turbine capacity. This amount should not be constrained by gas supply, other infrastructure or air quality constraints.

***Levelized cost summary:*** The estimated levelized lifecycle fixed capacity cost, and cost of delivered energy from a natural gas combined-cycle power plant are shown in Table I-33. Baseload costs represent the costs associated with the baseload section of the plant (385 MW, degraded lifecycle capacity for the reference plant). Incremental duct-firing costs are the incremental costs associated with the supplementary peaking capacity (25 MW for the reference unit) of the plant. The cost estimates are based on investor-owned utility financing. The baseload energy costs are based on 85% (of baseload capacity) capacity factor operation. The incremental duct firing energy costs are illustrative for 46% capacity factor (4000 hours per year) operation of supplemental firing. Fixed capacity costs include the fixed costs of the plant, fuel supply and transmission.

**Table I-33: Levelized Cost of Natural Gas Combined-cycle Power Plants**

| Resource | Service Year | Capacity ($/kW/yr) | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|---|---|
| Baseload | 2010 | $170 | $61.76 | $0.98 | $3.74 | $13.24 | $80 |
| | 2015 | $166 | $65.36 | $0.99 | $3.93 | $17.12 | $87 |
| | 2020 | $163 | $66.63 | $1.00 | $3.98 | $17.99 | $90 |
| | 2025 | $160 | $66.98 | $1.00 | $4.00 | $17.97 | $90 |
| | 2030 | $158 | $66.49 | $1.01 | $3.99 | $17.77 | $89 |
| Incremental Duct-firing | 2010 | $105 | $76.40 | $0.98 | $6.07 | $18.15 | $102 |
| | 2015 | $113 | $85.23 | $0.99 | $6.44 | $23.94 | $117 |
| | 2020 | $115 | $89.55 | $1.00 | $6.57 | $25.80 | $123 |
| | 2025 | $116 | $92.51 | $1.00 | $6.66 | $26.43 | $127 |
| | 2030 | $117 | $93.91 | $1.01 | $6.71 | $26.66 | $128 |

## *Advanced Nuclear Plant*

Commercial nuclear plants in the United States are "Generation II" designs based on light water reactor (LWR) technology developed in the 1950s for the naval nuclear program. In light water reactors (LWRs), energy released by fission of $U_{235}$ and the $Pu^{239}$ in the reactor core produces steam, either directly (boiling water reactors) or indirectly (pressurized water reactors with intermediate steam generators). The steam powers a steam turbine generator to produce electricity.

Following a three decade hiatus in planning for new nuclear plants, U.S. developers, as of late 2009, have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, largely in the southeast. The proposed plants would all employ Generation III (Advanced) LWR designs. Generation III designs feature increased standardization, passively operated safety systems, improved resistance to external impact, reduced probability of core melt events, factory-assembled modular components, extended plant life, extended fuel life and higher fuel burn-up and improved load-following capability. These features are intended to improve safety and reliability, reduce construction lead time, reduce construction and operating costs, to improve fuel use efficiency and reduce spent fuel production, and improve operating flexibility.

A consortium of countries is developing “Generation IV” reactor designs. Several technological alternatives are under development, but all would operate at higher temperatures to improve thermodynamic efficiency. Several would be optimized for hydrogen production and several would incorporate closed fuel cycles to improve fuel utilization, minimize potential for diversion and to minimize waste. In addition, interest has increased in small modular reactors (SMRs) with greater extent of factory fabrication, shorter construction times, smaller capital investment and better fit to individual utility systems. Several SMR concepts, based on both Generation III and Generation IV technologies, are under development.

***Reference Plant:*** The reference plant is an 1,117 MW net electrical output “Generation III+” unit based on the Toshiba-Westinghouse AP1000. The AP1000 is a two-loop pressurized light water reactor with standardized plant design, simplified, passively-activated safety systems, and extensive use of modular construction techniques. The first four AP1000 units are under construction in China, with the first unit slated for 2013 service. The AP1000 design has received its U.S. NRC design certification, but in response to a request for an amendment to the original design certification, NRC has requested modifications and testing to increase shield structure strength. The impact of this requirement on the schedules of the 14 AP1000 units proposed for US construction is uncertain. However, site preparation work for four Florida units has been suspended as of this writing because of regulatory and economic uncertainties. The reference plant would consist of the nuclear containment structure, turbine building, cooling towers, cooling water supply and discharge systems, auxiliary structures, transportation access, switchyard and transmission interconnection. It is assumed to be developed as a single unit at an existing nuclear plant site.

***Heat Rate:*** The full-load heat rate 10,400 Btu/kWh (33% thermal efficiency) (Westinghouse, 2003).

***Availability parameters:*** Advanced nuclear units are designed for improved reliability and reduced scheduled maintenance time. However, until more specific information becomes available the Council assumes that new and existing nuclear power plants will operate at availabilities consistent with the recent performance of existing commercial units. The availability parameters are based on NERC Generating Availability Data System (GADS) data (www.nerc.com).[35]

Scheduled maintenance and refueling outages - 28 days/yr (average)

Equivalent forced outage rate - 4.2%

Mean time to repair - 112 hours

[35] Earlier values, developed prior to the availability of 2004 - 2008 GADS data were used for portfolio model studies. These were as follows: Scheduled maintenance and refueling outages - 20 days (average) per year; equivalent forced outage rate - 5%; and, mean time to repair - 200 hours. These values yield the same equivalent availability (90%) as the final values derived from 2004 - 2008 GADS data.

Equivalent annual availability - 90%

Capacity-weighted 2004-08 averages for all nuclear units of 1,000MW and larger were used in deriving scheduled and maintenance outages and mean time to repair. In practice, nuclear units are typically refueled on an 18 or 24 month schedule so maintenance outages will vary from year-to-year.

***Unit Commitment Parameters***: Advanced nuclear units may provide increased operating flexibility compared to current plants. However, until specific information is available, the Council assumes that new and existing nuclear power plants will operate as base load units with limited dispatch capability. Unit commitment parameters used in the AURORA$^{xmp®}$ Electric Power Market Model are as follows:

Minimum load - 70%

Minimum run time - 120 hours

Minimum down time - 24 hours

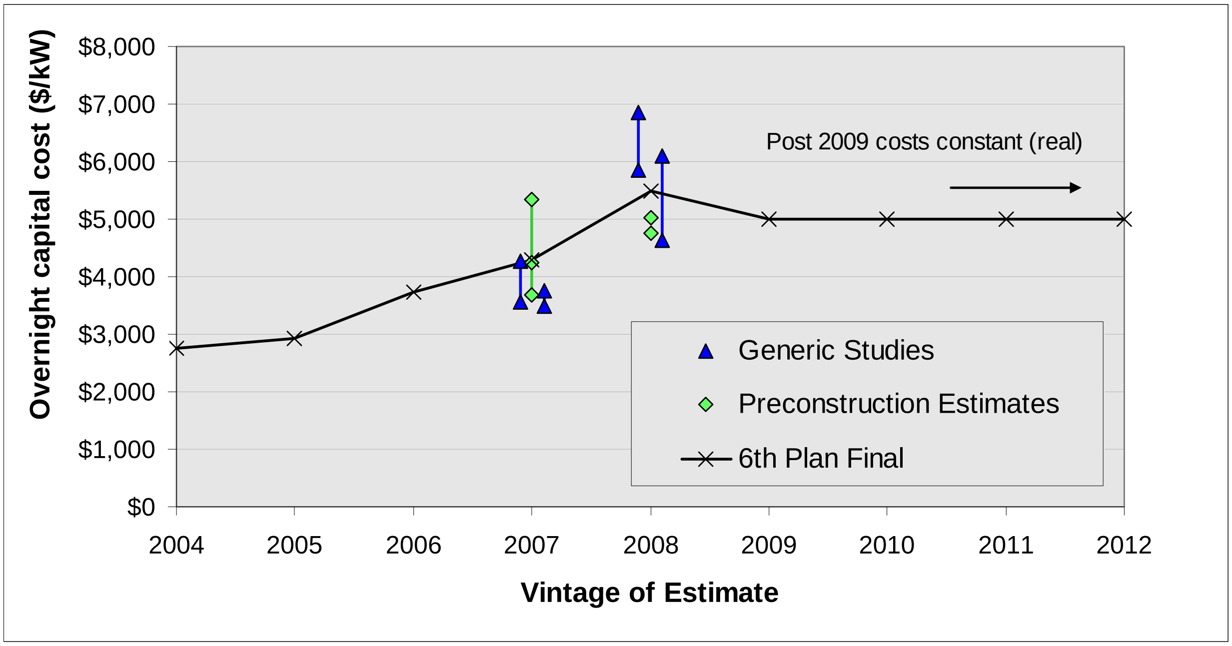
Ramp rate - 10%/hr (maximum)

***Total Plant Cost:*** The overnight total plant cost of the reference plant is estimated to be $5,500/kW in 2006 dollar values for the 2008 price year. This estimate was derived from 2007 and 2008 published estimates for new AP1000 units. These included 3 preconstruction cost estimates (one with expected, low and high bound estimates) and 4 generic cost estimates (each comprised of low and high bound costs). The sample costs were normalized as described in the Capital Cost Analysis section of this appendix to represent a new single unit at the site of an existing nuclear unit. The preconstruction estimates are for new two-unit plants, two at existing plant sites and one at a greenfield site. The cost estimates for plants located at existing nuclear sites were increased by 10% to account for cost savings associated with multiple-unit configurations. The estimated cost of the greenfield plant was not adjusted. Where not included, owner's costs of 22.5% of total plant costs were added to the estimates. The resulting normalized costs are shown in Figure I-28.

The rapid escalation of construction cost estimates for new nuclear units is evident from the 2007 and 2008 clusters and the 2004 - 2007 points of the Sixth Power Plan curve (based on the CERA nuclear plant historical construction cost index). The escalation rate for new nuclear units is more rapid than the general escalation of new power plant construction costs because of further detailed engineering of specific new nuclear units and globally limited production capability for large nuclear components. The 2008 Sixth Plan base year estimate was chosen to approximate the average of normalized cost estimates for 2008. The points for earlier years were derived by deescalating the 2008 cost using the CERA nuclear plant historical construction cost index. Nuclear construction costs are forecast to decline by 9% between 2008 and 2009, based on preliminary data from CERA. This decline is attributable to global softening of the heavy construction market, prospective expansion of global fabrication capacity for large nuclear components and deferral of planned completion dates for several proposed nuclear units. Post-2009 nuclear construction costs are shown as flat in real terms. Technological learning gained from construction of new units is expected to be offset by additional costs as detailed engineering, construction, startup, and shakedown of new units proceeds.

A capital cost uncertainty of +/-30%, roughly corresponding to the observed spread of normalized 2008 estimates, was used for the portfolio model risk analysis.

**Figure I-28: Total plant costs of advanced nuclear power plants**




***Development and Construction Schedule:*** The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are based on a ten-year overall schedule, from initial development of the NRC Combined Construction and Operating License Application (COLA) to commercial operation. Development and construction activities are assumed to overlap to the extent practical to minimize the overall project lead time. For example, site preparation and construction of facilities not subject to NRC jurisdiction is assumed to commence as soon as state and local permits are received. The extent of assumed overlap is consistent with current practice.

> **Development** (Preparation of COLA to receipt of combined construction and operation license) - 60 mo. (final 12 mo. concurrent with Early Construction). 5% of total plant cost for the 48 months not concurrent with Early Construction.
>
> **Early Construction** (Final engineering, major equipment order, site preparation, interconnection, infrastructure construction, start construction of non-NRC jurisdictional facilities) - 24 mo., 30% of total plant cost
>
> **Committed Construction** (NRC jurisdictional construction to commercial operation) - 48 mo., 65% of total plant cost

***Fuel Price:*** Currently operating commercial light water reactors in the United States are normally fuelled with a mixture of about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron, internally extending the supply of fuel. Though reactors using thorium and "bred" plutonium have been developed in anticipation of eventual shortages of natural uranium, it appears that the industry can rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast by EIA (EIA, 2008) to be stable through the planning period. The base price is $0.64/MMBtu in 2008, increasing slowly in real terms at an average of 0.8%/yr to $0.75 by 2030 (Table I-34).

**Table I-34: Forecast nuclear fuel prices (2006$/MMBtu)**

| 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $0.64 | $0.68 | $0.70 | $0.70 | $0.70 | $0.69 | $0.69 | $0.70 | $0.70 | $0.71 | $0.72 | $0.73 |
| **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | |
| $0.74 | $0.75 | $0.76 | $0.77 | $0.77 | $0.77 | $0.76 | $0.76 | $0.76 | $0.75 | $0.75 | |

***Operating and Maintenance Costs:*** The fixed O&M cost for the reference plant is estimated to be $90/kW/yr (inclusive of decommissioning fund and exclusive of property tax and insurance). The non-fuel variable O&M cost is $1.00/MWh. The O&M costs are based on the average 2007 operating and maintenance costs for operating U.S. nuclear units reported by the Nuclear Energy Institute (www.nei.org). The spent fuel disposal fee (a variable cost) was subtracted from the reported total O&M costs to obtain the fixed cost component. The spent fuel disposal fee was converted to 2006$/MWh and rounded to the nearest dollar to obtain the variable cost component. The remaining fixed component was converted to $/kW/yr units assuming an 85% capacity factor. To this was added the estimated decommissioning fund contribution using the high-end plant decommissioning estimate ($500 million) reported on the NEI website and the conservative assumption of decommissioning at 40 years. The resulting sum was rounded up to the nearest dollar to obtain estimated fixed O&M costs.[36]

Fixed costs are assumed to vary with total plant costs in real terms. Variable O&M costs are assumed to remain constant in real terms.

***Economic Life:*** The economic life of a new nuclear unit is assumed to be 30 years. This is likely to be a conservative assumption as the design operating lifetime of new nuclear units is 60 years and the original 40-year operating licenses of existing units are, in most cases, being extended to 60 years.

***Developable Potential:*** In terms of fuel supply and suitable sites, new nuclear units could serve all new electrical needs of the Northwest through the planning period, including scenarios where a substantial portion of existing coal capacity is curtailed or retired to reduce CO2 production. The principal limiting factor would be the earliest date that new nuclear capacity could be brought into service. A combined construction and development period of less than ten years is unlikely, so the earliest plausible service year is 2020. As a practical matter, committed construction of a Northwest unit is unlikely in advance of successful completion and operation of at least one of the proposed new units elsewhere in the United States, an established federal policy regarding spent fuel and aggressive development of equally cost-effective conservation and renewable resources. These conditions would likely preclude operation of a new conventional nuclear plant in the Northwest prior to the early to mid-2020s. 2023 was used as the earliest service year for portfolio studies.

[36] Following the development of the nuclear O&M estimates, it was learned that the NEI values are based on FERC Form 1 reporting and may not include administrative and general costs nor interim capital replacement costs.

***Levelized cost summary:*** The estimated levelized lifecycle cost of delivered energy from advanced nuclear power plants is shown in Table I-35. The cost estimates are based on investor-owned utility financing and and 85% capacity factor.

**Table I-35: Levelized Cost of Advanced Nuclear Power Plants**

| Service Year | Plant Busbar ($/MWh) | Ancillary Services and Integration ($/MWh) | Transmission and Losses ($/MWh) | Emissions ($/MWh) | Total ($/MWh) |
|---|---|---|---|---|---|
| 2010 | n/av | n/av | n/av | n/av | n/av |
| 2015 | n/av | n/av | n/av | n/av | n/av |
| 2020 | n/av | n/av | n/av | n/av | n/av |
| 2025 | $102.53 | $1.00 | $4.34 | $0.00 | $108 |
| 2030 | $102.53 | $1.01 | $4.35 | $0.00 | $108 |

# GLOSSARY

Definitions of terms used in this appendix.  The definitions below are generally consistent with usage within the industry.  In certain cases, however, the definitions used in the Plan may differ somewhat from the definitions as used elsewhere in the industry because of the nature of the Council's models or the societal cost perspective of the Power Plan.

***Engineering, Procurement and Construction (EPC) Costs:***  EPC costs include direct and indirect costs of plant construction, engineering, procurement and fees, often covered under a single contract.  Direct construction costs include the costs of field labor, equipment, materials and supplies for construction.  Indirect construction costs include construction supervision, payroll burdens, tools, facilities and field engineering.

***Gas Turbine:***  A gas turbine (also known as a combustion turbine) is a rotating continuous flow internal combustion engine based on an open Brayton thermodynamic cycle.  A gas turbine consists of a rotating air compressor to increase the pressure of incoming air; a fuel combustor to increase the temperature of the compressed air, and a gas turbine through which the heated, compressed air is expanded to produce mechanical energy.  A portion of the mechanical energy produced by the gas turbine is used to power the inlet air compressor and the remaining portion is used to drive a load.  In a gas turbine used for electric power generation, the load is an electric power generator.

***Heat Rate:***  A measure of thermal efficiency, in British thermal units of fuel energy consumed per kilowatt-hour of electricity produced (Btu/kWh).  A kilowatt-hour of electricity is equivalent to 3413 Btu, so a plant with a heat rate of 7000 Btu/kWh would operate at a thermal efficiency of 48.8%.  Unless otherwise indicated, in this report, heat rate is expressed on the basis of the higher heating value (HHV) of the fuel.

***Owner's Costs:***  Costs incurred directly by the project developer.  Owners Costs include including permits and licenses, land and right-of-way acquisition, economic and other social justice costs, project development costs, legal fees, owners engineering, project and construction management staff, startup costs, site infrastructure  (transmission, road, water, rail, waste water disposal, etc.), taxes, spares, and furnishings.  Because the Council's planning models test the cost-effectiveness of resource options at different points in time, the escalation and interest incurred during construction are not included in the base year Owners Costs.

***Overnight Costs:***  Plant construction costs exclusive of escalation and interest incurred during construction.  The cost of construction as if incurred instantaneously.  Sometimes called instantaneous costs.

***Total Plant Cost:***  The sum of direct and indirect engineering, procurement and construction (EPC) costs, contingencies and Owner's Costs, exclusive of escalation and interest during construction.

***Total Plant Investment:***  The sum of engineering, procurement and construction costs, owner's costs, financing costs, escalation and interest during construction.  Total Plant Investment costs will be in nominal (current) dollars and will vary by year of plant service.

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# Appendix J: The Regional Portfolio Model

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## INTRODUCTION AND SUMMARY

This appendix describes assumptions and methods of the Regional Portfolio Model (RPM). For the most part, each section stands alone and can be read in any sequence. Where this is not the case, the section will point to supporting material.

The description here is limited to changes since the Fifth Power Plan. Chapters 6, **Risk Assessment and Uncertainty**[1], and 7, **Portfolio Analysis and Recommended Plan**[2], of the Fifth Power Plan explain broader concepts, like the selection of resource portfolios. Appendices L,

1 http://www.nwcouncil.org/energy/powerplan/5/%2806%29%20Risk%20Section.pdf
2 http://www.nwcouncil.org/energy/powerplan/5/%2807%29%20Portfolio%20Analysis.pdf

**Description of the Portfolio Model**[3], and P, **Treatment of Uncertainty and Risk**[4], of the Fifth Power Plan explain the model's features in detail. This appendix will not repeat that material.

Instead, the appendix begins with the more apparent changes to the model, like the shift in cost and risk since the Fifth Plan. It then outlines key changes to the logic. A study of uncertainty highlights the main sources of economic risk to the region. Some thoughts about the modeling of risk conclude the appendix.

# CHANGES SINCE THE FIFTH PLAN

This section presents an overview of the model and data changes responsible for cost and risk shifts since the last Council power plan. The changes appear as a sequence of model revisions. This background helps explain differences appearing in later sections.

## *Overview of Data and Model Changes*

Modeling for the Sixth Power Plan began in February 2008. Staff assembled data for power prices and loads, fuel prices, and existing power plants. The model had not been used since the Fifth Power Plan. This exercise was to shake out problems and provide an early look at where the preferred resource portfolio might be headed.

These results were presented at the April 16, 2008, Power Committee meeting in Whitefish, Montana[5]. They resemble the Council's final resource plan. The early estimate of conservation potential, however, was much less than that which appears in the final plan.

Between February 2008 and January 2010, Council staff created thirteen renditions of the model. Each rendition has fixed data assumptions and logic. With each model, staff performed as many as 27 distinct studies or "scenarios." These studies examined questions raised by Council Members or staff. The studies typically involved changing a single assumption and observing the effect on cost, risk, and carbon emissions. In all, there have been over 280 separate studies, all but 20 of those done since January 2009.

Staff also created reports for each study to examine changes and provide reasoning. Two of these reports became routine. One lists the thousands of plans that the model examined and identifies the efficient frontier. The other illustrates the response of the least-risk plan to changing futures. They often go by the names of the "feasibility space" report and the "spinner graph."[6] Additional studies and reports are occasionally required to troubleshoot odd results or answer new questions.

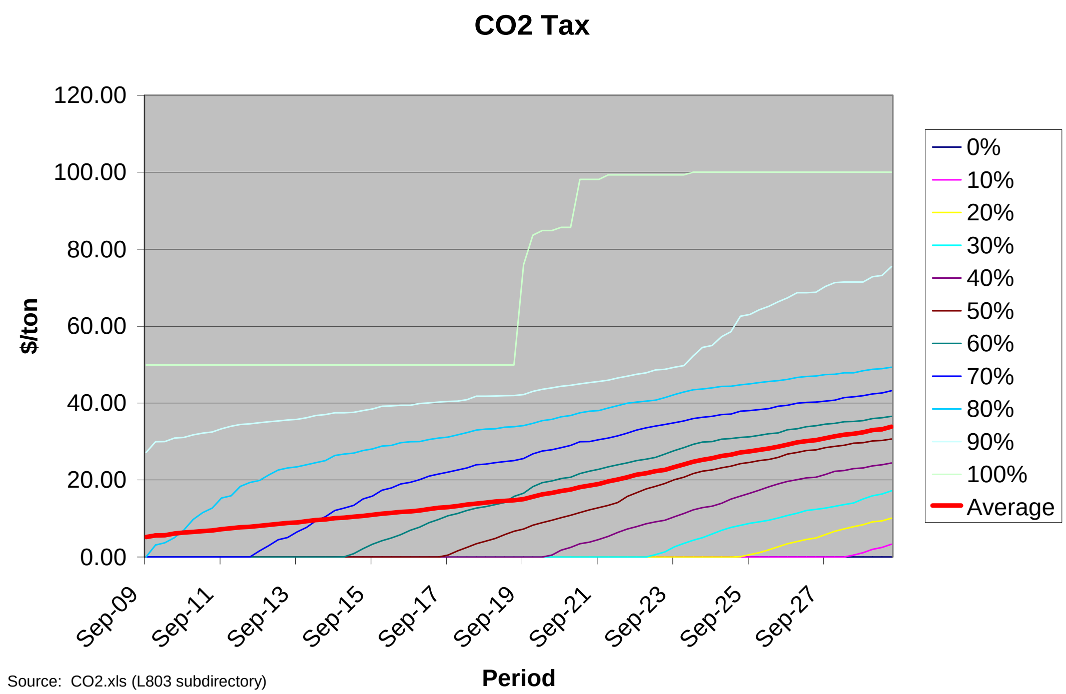
Model L801, run in late February 2008, reflects the data changes since the Fifth Power Plan. The model used for the final Fifth Power Plan is L28. The only difference in L801 logic from that of L28 is in the selection of the energy adequacy target level and in the test of economic value. The model uses the test of economic value to decide whether to proceed with building power plants.

3 http://www.nwcouncil.org/energy/powerplan/5/Appendix%20L%20%28Portfolio%20Model%29.pdf
4 http://www.nwcouncil.org/energy/powerplan/5/AppendixP.pdf
5 http://www.nwcouncil.org/news/2008/04/p3.pdf
6 The report for the final Carbon Risk scenario feasibility space is available at http://www.nwcouncil.org/dropbox/Analysis%20of%20Optimization%20Run_L813vL811.zip . References to web links for several spinner graphs appear in the section, Illustration with Selected Futures, below. Other reports are available upon request.

Most of the L801 input data changed, however.  The $CO_2$ penalty uncertainty increased in magnitude and likelihood.  Much like the fifth plan, the $CO_2$ penalty increases in steps, although the steps became $50 per ton and $100 per ton, instead of the $15 per ton and $30 per ton used in the Fifth Power Plan. The chance of seeing a penalty increased from 66 percent to over 90 percent.

Models L802 and L803 again changed the $CO_2$ penalty, as well as other assumptions.  Staff review served as the basis for these changes.  The distribution of carbon penalty appears in Figure J-1.  The effects of changes in major assumptions appear in Table J-1.  The actual total change differs from the sum of individual changes because the effects do not add directly.  The results from model L803 are the basis of the April 16, 2008, Power Committee report.

**Figure J-1: Carbon Penalty in L803 (April 2008)**




The next big change to the cost and risk of the model came with an end-effect adjustment for carbon penalty.  This is the "perpetuity adjustment."  The adjustment, introduced in July 2008 with L804, resulted in an increase of both cost and risk by a factor of three to four.  (Figure J-3 in the next section shows the resulting shift in cost and risk.)  The section **Perpetuity Factor and End Effects** in this appendix describes the adjustment in detail.

**Table J-1: Sensitivity of L803 Average Cost to Various Factors**

| | |
|---|---|
| **Fifth Power Plan without perpetuity** | **24,059** |
| | |
| **L803 plan NG price** | **24,560** |
| **L803 plan electricity price** | **23,976** |
| **L803 plan Loads** | **39,715** |
| **L803 CO2 penalty** | **28,539** |
| **All four L803 changes** | **49,320** |
| | |
| **Actual L803 Least-risk case** | **41,364** |

source: L811mini for illustrations L803.xls

Model L806 began service in early February 2009. It had what staff intended to be all the data and logic changes for the final portfolio recommendation. The original schedule called for adoption of the draft plan in April 2009. An intermediate version of the model, L805, was really a "restore point" for the model. Model L805 is a "known good" version of the model, before the addition of major changes to cost logic. The version L806 also has the first careful update to energy loads, resource descriptions, and fuel price data. It has the first model of RPS resources. Unfortunately, the schedule for the plan did not allow for a careful review of these extensive changes. Errors were introduced that were not discovered and corrected until version L810.

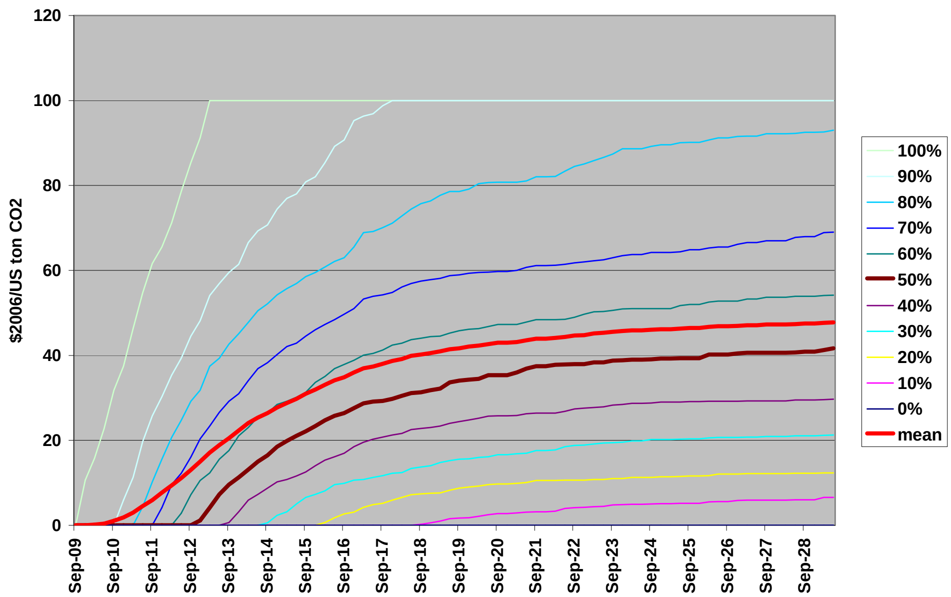
Models L807, L808, and L809 make small improvements to the code and data. The energy adequacy target moves about 2,500 average megawatts, but with little effect on cost and risk. L809 extends the hydrogeneration data to the 70-year record, but it is determined later that the energy for hydro independents is missing in about 20 percent of the hydro conditions.[7] This problem is corrected in L811.

L810 contains corrections to the problems mentioned above. A staff audit of logic and data revealed the problems, using new tools designed for that purpose. L810 also has new load data. The load forecast increased in the near term by almost 4,000 megawatts on peak in the winter. There was also a 3000 average megawatts energy decrease by the end of the study. These load forecast changes reduced the NPV cost of the system by $70 billion.

L811 is the basis for the draft plan. Besides correcting the hydrogeneration data, this version has a new CO2 penalty distribution. The expected arrival of some kind of carbon penalty is earlier in the study period. The distribution appears in Figure J-2.

7 Hydro independents are hydrogeneration units that are not coordinated as part of the Pacific Northwest Coordination Agreement (PNCA).

**Figure J-2: Deciles for Carbon Penalty**




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

Model L813 is the version used to analyze the scenarios in the final plan. Model L812 uses a new perpetuity adjustment that had some problems of its own. Fixing the perpetuity adjustment gave us L813. This appendix describes these issues and changes in the section, ***Perpetuity Factor and End Effects***.

Model L812, however, contains all of the other model and data changes for the final plan. The more prominent of the changes for the final plan were:

- ✓ new RPS logic,
- ✓ removal of forced-in buy-back demand response capacity,
- ✓ new performance uncertainty logic for conservation,
- ✓ revised discount rate,
- ✓ new load forecast,
- ✓ new fuel and electricity price forecasts, and
- ✓ revised existing resource data

This concludes the description of data and logic changes. The next section summaries the resulting changes in cost and risk.

## *Sources of Shifts in the Feasibility Space*

Figure J-3 shows how cost and risk have moved since the Fifth Power Plan The Fifth Power Plan resource portfolio model is labeled L28. The points are the cost and risk of the ***least-risk plan*** from each model-version base case.

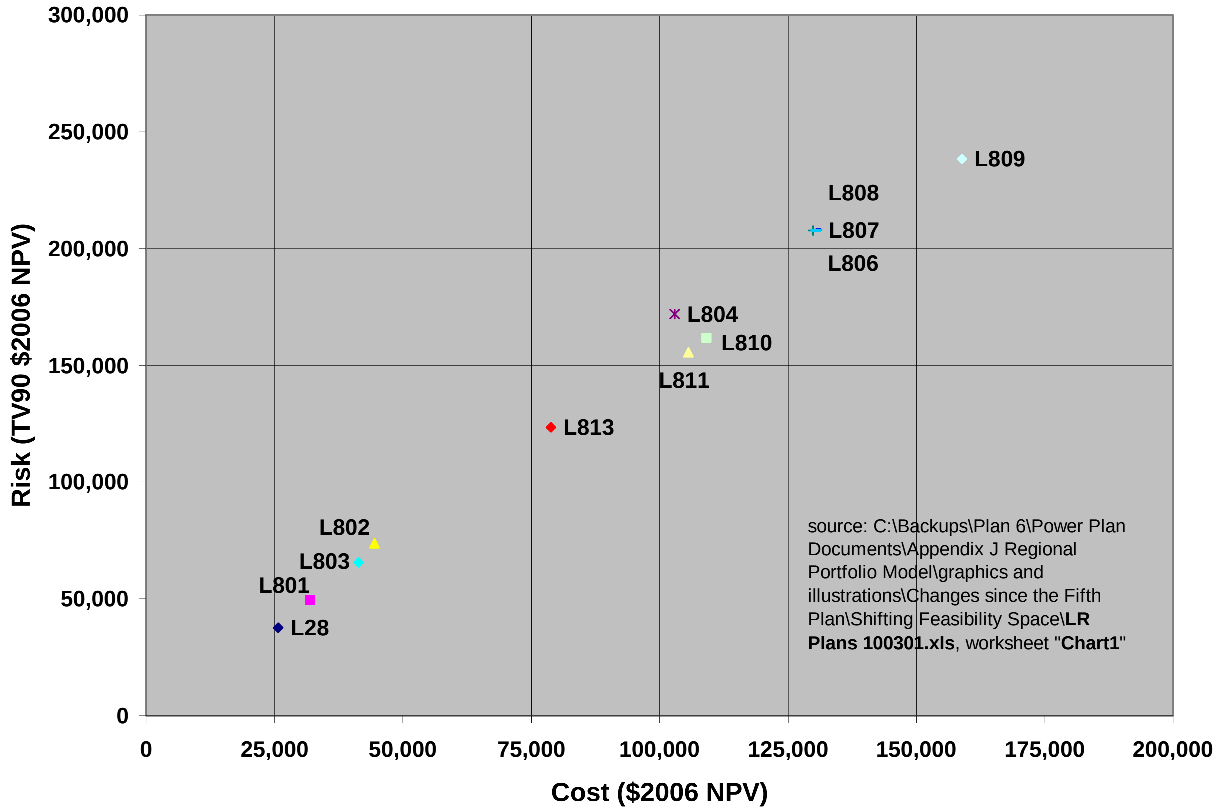
Costs and risk are subject to many factors. The choice of assumptions to be treated as uncertainties and the scale of uncertainty both have a bearing on overall cost and risk. The expected value of each assumption also affects cost and $TailVaR_{90}$ risk.

The first three versions of the model, L801 through L803, capture data changes since the Fifth Power Plan. As mentioned above, Fifth Power Plan uses $15 per ton and $30 per ton for the carbon penalty. Here, the cap is lifted to $100 per ton of $CO_2$. The distribution appears in Figure J-2. Costs and risks increase about 70 percent to 41.4 billion cost and 65.5 billion risk from the Fifth Plan levels of $24.5 billion expected cost and $35.9 billion risk. Without a more study, it is hard to say how much each change accounts for the cost and risk differences. The decrease from L802 to L803 seems to be due primarily to limiting the carbon penalty to $50 per ton of $CO_2$ until the second half of the study.

A simplified version of the model provides a way to perform sensitivity analysis. Instead of futures, the simplified version uses expected values for load growth, wholesale electricity and natural gas price, carbon penalty, and so forth. This model shows us the sensitivity of costs to changes in assumptions without the "noise" present in individual futures. Table J-1 indicates that the change in load forecast contributed the most to cost change between L28 and L803.

With the new perpetuity factor in L804, costs increased by 150 percent. At first glance, this increase seems too large. Consider an even stream of cash flows over 20 years contrasted with the same cash flows taken to perpetuity. At five percent, the former would have a net present value (NPV) that is 55 percent of the latter's. The L804 model's perpetuity adjustment is applied, however, only to costs subsequent to the arrival of carbon penalty. The sample of costs used by this adjustment will typically be much higher than those prior to the arrival of the carbon penalty. Consequently, the adjustment will typically be much larger than one based on average costs over the study.

**Figure J-3: Evolution of the Feasibility Space**




The model L806 reflects the first thorough data review since the Fifth plan. The cost data for models L806 through L809, however, is suspect for the reasons described in the previous section. The values for model L810 are reliable, however. The very large drop in costs between L809 and L810 is due primarily to a change in the load forecast.

Average cost and risk did not change much between L810 and L811. This is true despite many changes in data and code, including a new carbon penalty distribution illustrated in Figure J-2. The year in which there would be a 50:50 chance of a carbon dioxide penalty moved to 2012 from 2019.

In L813, cost and risk falls again. The model uses lower natural gas prices and the loads are lower in the middle-term of the study. The lower load forecast stems from recognition of the effects of the recent economic recession. By the end of the study, loads have recovered.

## *The Reasons for Increased Conservation*

The model finds large amounts of conservation cost effective. The cost of some of the conservation is above long-term wholesale power market price ("electricity price", "power price" or "market price"). Many utilities use this price as a measure of cost effectiveness. They apply it not only of conservation but to all resources. They do so because it can be viewed as the utility's avoided cost. This section explains why the cost effectiveness for conservation can be higher than the wholesale power market price.

First, it is helpful to review how the model decides to acquire conservation. The model uses a decision criterion ("criterion"), as this section explains. There are two parts to the criterion, and they work in different ways. The two parts are the "adjusted market price" and the market adder.

In each period of each future, the model buys conservation from a supply curve up to the criterion value. The supply curve is like a stack of conservation programs, sorted by price. Programs can have different sizes (reductions in electricity use) as well as different prices. There are separate supply curves for lost opportunity and discretionary conservation. The real levelized cost for each program acquired is added to the cost of conservation already acquired.

The adjusted market price reflects considerations unique to valuing conservation. The adjusted market price, for example, weights market prices according to the *distribution* of energy reductions. It also averages market prices over recent history. Averaged market prices stand in for forecasts of long-term market price. Views of the long-term market price tend to follow spot prices and other recent news. They change more slowly, however, just like an average. The decision point also lags the averaging period by a year. Utility budget cycles and decisions give rise to the lag effect. Another difference with market price is the ratchet mechanism used for lost opportunity conservation. The ratchet comes from the nature of codes, laws, and standards, which govern much lost opportunity conservation acquisition. That is, once adopted, laws and codes are rarely reversed.

The market adder is the second factor controlling how the model acquires conservation. As the name suggests, this value is added to the adjusted market price to determine how far up the conservation supply curve to go.

The market adder is one of the elements of a plan, and the model experiments with the value of the adder to reduce cost at each level of risk. The model tries a range of adders, from negative values to as high as $100 per megawatt-hour. Of course, the model is also trying different combinations of other generation resources as it does so. The market adder for plans on the efficient frontier is therefore the results of the model's search process.

One way to understand how factors affect conservation development is to begin with the simple model described in the preceding section. Adding factors one at a time gives us an idea of their relative importance. Because the order of the additions matters, however, some care is necessary in interpreting the results.

The starting point is replacing each uncertainty with a deterministic forecast. Using the Council's adopted electricity price forecast leads to about 4,088 average megawatts of conservation[8]. The electricity price forecast used for this initial estimate assumes no carbon penalty.

The effect of changes to the model depends on the order in which the changes are made. This description follows one path. Table J-2 contains the result of studies using the various models. It shows how applying the changes in a different order would change the effect.

Stochastic variation in electricity price, assuming no carbon penalty, adds 389 average megawatts, bringing the total to 4,477 average megawatts. This variation is the result of uncertainty and

8 …\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation\Copy of L813miniCnsv01 100301 step 00.xls

variation in natural gas price and the construction costs for power plants. It is also due to hydro generation variability, load growth excursions, and many other factors.

Stochastic variation increases acquisition for several reasons. Discretionary conservation has a single supply curve for the entire study. The supply, once accessed, is not restored. Variation in electricity price drives the decision criterion higher earlier than otherwise. The last high water mark, so to speak, is the level at the end of the study. Lost opportunity conservation has a similar ratchet mechanism in its criterion, as described earlier.

Carbon penalty uncertainty moves the wholesale market electricity price up and, consequently, moves up the cost effectiveness threshold for conservation. Introducing the carbon penalty uncertainty increases conservation energy by 470 average megawatts, to 4,947 average megawatts, by the end of the study. The model handles the representation carbon penalty directly. It is therefore possible to cull the contribution from this source of uncertainty from the others.

Finally, we have the effect of market price adders. The adders increase acquisition by 1,011 average megawatts, to 5,958 average megawatts. The adders in the least-risk resource portfolio from the Carbon Risk scenario are different for lost opportunity and discretionary conservation. The former gets a $50 per megawatt-hour adder; the latter garners an $80 per megawatt-hour adder.

The results are summarized in Table J-2. It may be useful to see the effect if discretionary conservation got the same $50 per megawatt-hour adder as lost opportunity conservation. This situation is included among the studies presented here.

**Table J-2: Conservation Acquisition Factors**

| Conservation Acquisition by End of Study | Carbon Penalty | LO market adder | NLO market adder | Lost Opportunity MWa | Lost Opportunity average cost $/MWh | Discretionary MWa | Discretionary average cost $/MWh | Total MWa | Total average cost $/MWh | Reference |
|---|---|---|---|---|---|---|---|---|---|---|
| Deterministic models | | | | | | | | | | |
| base case | N | 0 | 0 | **1,835** | **11.40** | **2,253** | **23.25** | **4,008** | **17.93** | **1** |
| average carbon penalty | Y | 0 | 0 | **2,180** | **16.65** | **2,479** | **26.01** | **4,660** | **21.63** | **2** |
| equal adders | N | 50 | 50 | **2,854** | **28.22** | **2,584** | **28.16** | **5,438** | **28.19** | **3** |
| final plan adders | N | 50 | 80 | **2,854** | **28.22** | **2,727** | **32.05** | **5,582** | **30.09** | **3** |
| average carbon penalty + equal adders | Y | 50 | 50 | **3,037** | **32.28** | **2,719** | **31.78** | **5,755** | **32.05** | **3** |
| average carbon penalty + final plan adders | Y | 50 | 80 | **3,037** | **32.28** | **2,812** | **35.08** | **5,849** | **33.63** | **3** |
| Stochastic models | | | | | | | | | | |
| base case | N | 0 | 0 | **2,072** | **15.30** | **2,405** | **25.40** | **4,477** | **20.90** | **4** |
| carbon penalty | Y | 0 | 0 | **2,395** | **21.30** | **2,552** | **28.10** | **4,947** | **24.90** | **5** |
| equal adders | N | 50 | 50 | **2,963** | **30.60** | **2,672** | **30.70** | **5,635** | **30.60** | **4** |
| final plan adders | N | 50 | 80 | **2,963** | **30.60** | **2,787** | **34.30** | **5,750** | **32.40** | **4** |
| carbon penalty + equal adders | Y | 50 | 50 | **3,092** | **33.70** | **2,767** | **33.80** | **5,859** | **33.80** | **5** |
| carbon penalty + final plan adders | Y | 50 | 80 | **3,092** | **33.70** | **2,867** | **37.69** | **5,958** | **35.63** | **6** |

The results of the stochastic models are averages over 750 futures.

**1** C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**Copy of L813miniCnsv01 100301 step 00.xls**

**2** loc. cit., **Copy of L813miniCnsv01 100301 step 01.xls**

**3** loc. cit., **Copy of L813miniCnsv01 100301 step 02.xls**

**4** source: … \Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**L813_Cnv1.xls**

**5** source: … \Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Sources of Conservation**L813_Cnv0.xls**

**6** source: ….\Plan 6\Studies\L813**Analysis of Optimization Run_L813vL811.xls**

Source: workbook "L813_conservation_sensitivity 100301.xls," worksheet "Table"

Some of the entries in Table J-2 require explanation. Each row describes the results of a particular study. The first column indicates whether there is a carbon penalty present. The model uses average carbon penalty across future in the deterministic models. If the model is stochastic, it uses the full 750 futures of carbon penalty. The second and third columns have the market adders for lost opportunity (LO) or discretionary (NLO) conservation. The values to the right of these columns identify the average megawatts (energy) developed and the cost of conservation. Both of these values are for conservation at the end of the study. The costs are averages across futures for all conservation acquired up to the end of the study.

At the far right is a column that contains numbers which refer to the references at the bottom of the table. These references indicate where to find the corresponding model results.

# ENHANCEMENTS TO THE MODEL

The following are changes to the model logic since the Fifth Power Plan. The Fifth Power Plan, especially Appendices L and P, describes the model as it stood at that time. Many of the underlying concepts remain the same. The discussion here emphasizes the changes that could affect the results of the model.

## *Capacity and Costs Related to Capacity*

In the early stages of developing the Sixth Power Plan, stakeholders and the Council identified construction cost uncertainty as a concern. Treating the uncertainty in construction costs, however, raises other questions. Should uncertainty in construction costs be tied to the seasonal or long-term capability of a unit or to the original nameplate capacity? How do other costs vary? Is fixed operation and maintenance cost similarly affected? Should capacity or capability be variable? Should the model give the user the ability to vary these factors deterministically, as well?

Ultimately, all of these features found their way into the revised model. Making the changes at the same time afforded economies of time and effort. Moreover, because of the nature of these changes, there is less chance of errors if other features are added at the same time. The basic changes are complicated enough that the overall architecture of the logic must be mastered again. Other modifications that could be made with little or no additional development effort therefore were completed. For example, a relatively simple enhancement was the addition of uncertainty in commercial availability of a new technology.

The following is a summary of and introduction to the sections that follow. These are changes only to capability and fixed cost features of the model:

- In the Fifth Power Plan, construction costs did not have the kind of detail that staff needed. Specifically, mothball and cancellation costs depend, in a sensitive fashion, on when the decision is made to defer or cancel construction. Enhancements for the Sixth Power Plan model now reflect those preferences.

- Internalized decision making, including decisions based on forward-going fixed costs, became not only preferable but in fact necessary.

- Provisions now exist for adjusting all fixed costs, including fixed operations and maintenance (FOM) and construction cost, both deterministically and stochastically.

- Enhancements also provided for adjustable capacity due to seasonal effects and adjustment over the study, both for cost and for energy calculation purposes.

- Finally, staff anticipated that retirement logic would be useful for evaluating the implications to coal-fired power plants of carbon penalties. It would also provide more realistic modeling of less efficient gas-fired units in the region.

In total, there about 16,388 combinations of new features and their interaction can be subtle. These are enumerated at the end of the section.

As a basis for describing the enhancements, understanding of some features as they existed in the Fifth Power Plan is helpful. The next section introduces that background.

## Fixed Cost and Capability Treatment in the Fifth Power Plan

In the model, construction may begin in any period, subject to user choice. That is, the model permits additions to be made in every period, but the user must specify the maximum amount of each type of resource that can be added in that period.

When the model runs under the ***optimizer***, the optimizer tries different amounts of capacity within the permitted range for each type of resource. Whenever a study tries to identify the efficient frontier and the least-risk plan, it is an optimizer that is doing the work. It is the optimizer that creates and tests the plans under identical sets of futures.

***Cohorts*** are identical units that may begin construction at the same time. Units are identical in the sense that they have the same technology and fuel, and they face exactly the same costs and market prices. They have the same unit size. Cohorts exist because the model adds new capacity in multiples of some fixed unit size.

In a given period, for example, a plan may specify that only one unit can begin construction, only two units may begin construction, or some other pre-specified number may begin construction. Of course, because all cohorts face the same circumstances, all cohorts see the same decision criterion value and will respond identically.

One feature that has not been used in either the Fifth Power Plan or the Sixth Power Plan is discretionary addition of resources by the model under favorable market conditions. The reason for excluding this option is probably obvious: the Council is tasked with producing a resource portfolio, including the timing and selection of resources. The subject feature leaves that decision to the market place. The selection of this feature, therefore, would be in a sense an abdication of the Council's role.

Nevertheless, if the user selects this feature, he or she must specify the maximum number of units that may be added in a particular period. Without that limitation, nothing would restrain the model from adding an arbitrary number of units whenever the market indicated that a single unit could make money.

The model partitions construction activities into three phases. There is an initial ***planning phase*** which is often quite long but typically costs only 1 or 2 percent of the overall project budget. In Council studies, the optimizer assumes that this phase has been completed. The model associates with a plan the cost of the planning for each resource in that portfolio. The decision criterion for construction is not used during this phase.

The second phase is an ***early construction phase***, during which the decision criterion determines whether to continue with construction or to defer or cancel the unit. The third phase is a ***late construction phase***, during which construction continues without regard to circumstances. The plant is completed and brought online. It is assumed that most of the money has been spent before this third phase begins. The best economic outcome at that point is to complete the plant and let it produce whatever value it can.

In the Fifth Power Plan, the rate of expenditures was the same for the early and the late phase of construction. Construction costs rates are more flexible in the new model, as this appendix will explain.

Another feature of the original construction logic was a provision to have all of the funds spent in the first period of each construction phase.  It has been observed that very often, expenses are not even during a phase, but instead much of the expense is up front.  These up-front expenses are for key components, often the initial or final payments on boilers or combustion turbines.  These junctures also mark the beginning of a new phase of construction.  By providing the capability to represent this in the model's logic, the relation of expense to decision making is more credible.

These existing capabilities must be integrated with the new features, however.  We will return to this task in the context of each feature.

## More Detailed Specification of Construction Costs

In the model, deferral (mothballing) and cancellation can occur only during the early construction phase.  For the Fifth Power Plan, whether the decision was made early or later in this early phase had no impact on the cost.  For the Sixth Power Plan, the logic allows that if the decision is made early, the cost is less.

There are at least two types of mothball costs – a fixed, one-time charge, and a charge for each period construction is deferred.  In the Fifth Power Plan, the model used only the latter.  This is one area where no significant improvement has been made.  Unfortunately, recognition of the fixed component of mothball costs came only at the end of the development process. Also unfortunate is the fact that the fixed costs appear to dominate the variable costs.  They can be as much as 32 times larger than the variable costs. Repairing this deficiency has therefore moved to the top of the task list for the next version of this logic.

Several unanswered questions about mothball fixed costs remain.  For example, is it applied again if construction restarts and then stops again?  Study of these costs is warranted before making any more advances in this area.

Mothball and cancellation costs are capitalized and amortized, rather than expensed.  To expense them would introduce distortions in economic value calculations.  The assumption holds that costs prior to the end of the study are representative of life-cycle costs.  Mixing conventions would distort this representation.

Note that there is no treatment of deferral and cancellation during the planning and late construction phases.  The planning and late construction activities are insensitive to decision criteria, by assumption.

Finally, deferral and cancellation costs can arise during retirement of power plants.  Modeling these has its own set of issues.  The section **Economic Retirement** below discusses the issues.

Any adjustments or escalation in the real cost of construction, deferral, or cancellation will be applied to construction and retirement costs in the same way.  The Council’s Generation Resource Advisory Committee (GRAC) recommended this policy, and there is no compelling reason to do otherwise.

## Uncertainty in Construction Costs and in Fixed and Variable O&M Cost

The Sixth Power Plan model implements uncertainty in construction costs and in fixed and variable operation and maintenance (O&M).  The model uses multipliers that differ from period to period. Each future has a distinct sequence of multipliers with strong correlation from one period to the next. The Fifth Power Plan model had no such treatment.

The treatment of uncertainty for expenses differs fundamentally from that of capitalized cost. The construction cost incurred in a given period is affected by the multiplier in force only in that period. The levelized value of that period's cost then carries forward to each remaining period of the economic life of the unit. This is not true, however, for fixed and variable operations and maintenance (O&M). Fixed and variable O&M multipliers affect only their period costs. Levelized costs do not carry forward to subsequent periods.

## Economic Retirement

The current model takes a more realistic approach to the treatment of economic retirement than did the Fifth Power Plan model. In the Fifth Power Plan, the model reflected a prescriptive loss of about 1,000 megawatts of inefficient gas-fired generation in the region. Understanding the effect of a carbon penalty to power plant economics is also a motivation to better modeling in this area.

Economic retirement is signaled by decision criteria based on forward-going fixed O&M cost. If the decision criterion is negative for a prescribed number of periods, the model effectively decommissions the unit.

In principle, this feature could be available for both existing, non-surrogate plants and for new candidates. ***Surrogate plants*** are as those that represent a class of similar dispatchable units. The units are similar in the sense that they have identical fuel type, heat rate, variable O&M costs, technology, and fuel cost. They dispatch, therefore, at the same electricity price and produce the same value per period.

A decision criterion for new candidates, however, requires separate tracking of fixed O&M for every cohort. Each cohort will have a distinct fixed cost requirement due to prior commitments. Each cohort will therefore have its own threshold for economic feasibility. This means new logic is necessary to track these elements. For example, when a new plant comes online, an offset of units and fixed O&M are added to a period at the end of the plant life. If the unit is retired early, however, these values need to be removed and replaced by the revised values.

These complications and the press of the Sixth Power Plan schedule forced the decision to pick up such improvements later. Power plant retirement is only available for simple existing units.

Other expectations, however, support this limited scope. Any specific existing resources that are candidates for retirement probably merit their own representation. Any new resource candidates should be more efficient than existing units. Their retirement, therefore, would be unlikely.

## Uncertainty about Commercial Availability

New technologies usually have uncertainty about ***commercial*** availability. Even if a generation technology is feasible, there often is uncertainty about its eventual cost and ease of implementation. In discussions with various advisors, the following representation emerges.

At the beginning of each future, the value of a random variable is selected. This variable has as its value the year when commercial availability is achieved. It may be that this value is beyond the study horizon. In that case, the technology effectively is never commercially available.

As with other new candidates, cohorts can be constructed in any period the user specifies. The pre-study logic, however, assigns a special status code to all periods before the commercial availability variable's period. This status code indicates that the cohort is not commercially available. This has the effect of causing the schedule to simply slip until the technology becomes available and the first period of planning or construction phase can begin.

Note that all cohorts are treated equally in this case. All cohorts will become available in the same period.

One question associated with this representation is whether there are costs incurred during periods in which the technology is not commercially available. Another question is whether a technology should lose its siting and licensing if it doesn't become commercially available within specified amount of time. For this first version, the technology does automatically lose its license and terminates. The maximum delay is equivalent to the time limit for mothball status.

Finally, how do the deferral and cancellation cost due to commercial infeasibility compare with those due to construction? In the current version of this feature, the deferral cost is the same as for the "first period" construction mothball decision. For further discussion, see the section, ***More Detailed Specification of Deferral and Cancellation Costs***.

## Integrated Forced Outage Rate

One of the deficiencies in the Fifth Power Plan model was forced outage behavior for new resource candidates. In actuality, new units bring a diversification effect. We had not accounted for this in the Fifth Power Plan model. Only a block deration for forced outages of new candidates existed.

The objective of this new logic therefore is to provide cohort-specific forced outages. This produces the diversification effect and improved reliability of the ensemble. Of course, the deration option is still available.

One of the benefits of handling forced outage rates internally is reduced reliance on Crystal Ball® random variables. The Crystal Ball random variable calculation is slow. Most of the 1,100 random variables the Fifth Power Plan's model employs are for modeling forced outage rates associated with large, existing thermal units. The new planning flexibility function permits not only better treatment for forced outages of new and existing power plants, it reduces the number of Crystal Ball random variables to 384.

### *Consequences for the Algorithms*

The Sixth Power Plan's model calculates outages for all cohorts of all plants at the beginning of each future. An alternative is to calculate and store forced outage events beforehand. The model then would use a Crystal Ball random variable to select the outage values for each future, plant, period, and cohort. This has the disadvantage, however, of requiring significant storage. If storage needs become large, that can increase execution time as well. Consequently, the model adopts the first approach that did the job.

Forced outages use the following model. Overall power systems fail when a series of components fail. Each component is assumed to have failure rate with an exponential distribution, a standard assumption. For multiple component failures, the system will have a gamma distribution, which is determined by the Mean Time to Failure (MTTF). Similarly, we assume that the simple systems must be repaired before the restoration of the overall system is complete. Restoration will similarly have a gamma distribution determined by a Mean Time Before Repair (MTBR). Again, the components have exponential distribution. We assume one-half dozen simpler systems fail and require repair.

The random variable for the forced outrage rate (FOR) is the ratio MTBR/( MTTF + MTBR), which will have a beta distribution. Knowing the FOR and MTBR is adequate to computing all the other information necessary to specify the distribution.

## Variable Capacity

Variable capability of power plants over time is another new feature. Capability might vary by future as well as period, and it might change stochastically or deterministically. Important applications of this feature include representing maintenance and seasonal efficiency.

There is a problem, however, with doing this for surrogates and for new candidates. These are collections of plants. The model currently cannot tell which cohort or plant within a collection to modify.

Consequently, any kind of unit can have variable capacity, but with limitations. For surrogate units and new candidates, the same adjustment applies to all units or cohorts in each collection. That is, the adjustment is simply applied to all output of the collection.

One concern is how or whether this adjustment should affect decision criteria for new plants and for economic retirements. The economic feasibility of a plant is determined on a per-megawatt basis. If the variation is seasonal, however, the expected capability is affected. The adequacy calculation for the decision criterion is also affected. The annual average must be calculated for the decision criteria in these situations. Otherwise, variations in capability are unforeseeable and would therefore not affect the decision criteria.

Adjustments to capacity do not affect costs associated with construction. In principle, they could. A future version of the model will permit the user to specify whether or not this is the case.

For this adjustment, a new capability permits cyclical reading of input data. For example, assume a sequence of adjustments for the first four hydro quarters. The model will return to the first period's adjustment for a value to use for the fifth period, and so forth. This happens automatically if the data are not provided for every period.

## New Utilities

New utilities provide greater transparency of the model's internal calculations. This improves understanding and the reliability of the model and data. For example, it is now easy to report:

- Forced outage rate, by cohort, plant, and period.
- Capability for adequacy estimation.
- Internal decision criteria estimation, by cohort, plant, and period. Supporting values are also available.

- Fixed O&M adjustment by cohort, plant, and period.
- Capital costs by cohort, plant, and period
- Information about the construction status of new units

Special auditing software now provides the ability to look not only at the value of ranges within the model's worksheet, but also the content of selected Microsoft® Visual Basic® arrays. These arrays are used to store detailed information about the state value of each existing and new resource. These can be extracted in a number of formats, including those suitable for spinner graphs, pivot tables, and database records.

## Input Variables and Feature Selection

The user selects options from a compact matrix next to each resource. Below, in Figure J-4, the new capabilities are in the first row. The second row of variables is identical to those in the Fifth Plan model, with one exception. The exception is highlighted in yellow and uses red font. There is a slight change in the interpretation of that value, as explained by a comment in that cell.

**Figure J-4: Fixed Cost and Capability Specification**

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | 610 MW CC 030708 | | | |
| Option Selection (integer) | FOM (R $M/ MW/ period) | Late Constr Costs (RL $M/ MW/ Period^2) | Earliest Availability (Period) | Regional Share | Retirement mothball life (periods) | Retirement evaluation cost (RL $M/MWPeriod) | Decommisioning cost (RL $M/MWPeriod) | First Period Mothball Costs(RL $M/ MW/ Period) | First Period Cancellation Costs (RL $M/ MW/ Period^2) | Generation technology | Status | LT Fuel Price (Range name) | MTBR (weeks) | FOR [0…1] | Nameplate (MW) - required for cost calcs of existing units only | | | |
| 44144 | 0.013101 | 0.003000 | | 100% | | | | 0.000029170 | 0 | CCCT | New | | | 0.05 | 378.3 | | | |
| Criterion Set ID | Planning Periods | Early Construction Periods | Late Construction Periods | Development Costs (RL $M/ MW/ Period^2) | Mothball Costs (RL $M/ MW/ Period) | Cancellation Costs (RL $M/ MW/ Period^2) | Early Constr Costs(RL $M/ MW/ Period^2) | CancelThreshold ( | Const Cost Escl (.01=1%/period) | ResourceLife (periods) | OptionLife (periods) | Market-driven ramp rate (MW) | Planned Development Costs (RL $M/ MW/ Period^2) | **Index** | | | | |
| CCCT Criterion_004 | 0 | 4 | 6 | 0 | 0.00068613 | 0.0014288 | 0.003137106 | -99999 | 0.000% | 120 | 20 | FALSE | 0.00132581 | 0 | | | | |
| | | | | | | | | | | | | | | | Construction Cost Variation | 1 | 1 | 1 |
| | | | | | | | | | | | | | | | Manifest Capability (MWa) | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | Cost ($M Real) | 0.0 | 0.0 | 0.0 |
| | Study ID | Availability | DHF(0=Dis | Fixed Ener | Fixed Cost ($/I | Fuel Set (ID | Heatrate (MMB | Planning Flexibility ID | Capacity ID (I | Cap_Decisior | Variable Cost | Hydro Structure ID | | 12 | Energy(MWh) | 0.0 | 0.0 | 0.0 |
| | 1 | (none) | 0 | (none) | (none) | PNW East N | 7.1 | CCCT-01 Annual_004 | CCCT Capaci | 0,6000,1500,( | 1.82 | (none) | | | Cost ($M) | 0.0 | 0.0 | 0.0 |

The user specifies which combination of features the model will use with an integer in the first column of the new row. In a separate location within the RPM, the user can specify with simple yes or no flags whether to use the particular option. The worksheet returns the integer corresponding to the choices. The coding logic appears in Figure J-5.[9] The user may also need to decode a particular option selection from the integer. Figure J-6 illustrates the formula in the workbook that performs that function.

9 At first glance, this figure suggests that a much larger number, 65536, are available. In fact, one option is not currently in use. Also, the selection of the 2004 logic excludes the use of other options, except for market additions and early use of all early construction funds in the first period of early construction.

**Figure J-5: Encoding the Selection of Options**

| | Option selection | Plant status (for data validation) | |
|---|---|---|---|
| 1 | no | Use 2004 logic | Existing |
| 2 | no | FOM Variable (& differs each gam | Existing Aggr |
| 4 | no | VOM Variable (& differs each gam | New |
| 8 | no | Capability Variable? | |
| 16 | yes | Construction Cost Variable (& differs each game)? | |
| 32 | yes | Use Distinct Cost for Committed Construction? | |
| 64 | yes | Use Internal Decision Criterion? | |
| 128 | no | Economic Retirement Logic? | |
| 256 | no | Stochastic FOR? | |
| 512 | no | Stochastic Availability? | |
| 1024 | yes | Use Distinct Cost for Mothballing in First Period? | |
| 2048 | yes | Use Distinct Cost for Cancelling in First Period? | |
| 4096 | no | Capability Differs Each Game? | <== not currently in use |
| 8192 | no | Spend early construction phase cash in first period | |
| 16384 | no | Permit Market Additions | |
| 32768 | yes | Read construction costs from the internal array | |
| | 35952 | | |

Figure J-7 has detail from the first row in Figure J-3. This particular example is for an existing surrogate natural-gas fired power plant. After the first column, most of the remaining input data values have ranges, units, and types that are apparent from the context. Some are not, however, and explanation is necessary.

**Figure J-6: Decoding a Selection of Options**

| | | 44144 | |
|---|---|---|---|
| | | INVERSE | |
| 0 | 1 | FALSE | |
| 1 | 2 | FALSE | |
| 2 | 4 | FALSE | |
| 3 | 8 | FALSE | |
| 4 | 16 | TRUE | Construction Cost Variable (& differs each game)? |
| 5 | 32 | TRUE | Use Distinct Cost for Committed Construction? |
| 6 | 64 | TRUE | Use Internal Decision Criterion? |
| 7 | 128 | FALSE | |
| 8 | 256 | FALSE | |
| 9 | 512 | FALSE | |
| 10 | 1024 | TRUE | Use Distinct Cost for Mothballing in First Period? |
| 11 | 2048 | TRUE | Use Distinct Cost for Cancelling in First Period? |
| 12 | 4096 | FALSE | |
| 13 | 8192 | TRUE | Spend early construction phase cash in first period |
| 14 | 16384 | FALSE | |
| 15 | 32768 | TRUE | Read construction costs from the internal array |

**FOM (R $M/ MW/ period) – fixed operation and maintenance cost** – This is fixed operation and maintenance expense expressed in millions of constant (or "real") dollars per megawatt per period. The final fixed O&M rate is subject to any escalation and variation multiplier.

**Late Constr Costs (RL $M/ MW/ Period$^2$)** – If the user specifies a distinct cost for construction during the late construction phase, the rate is specified here in real levelized millions of dollars per megawatt per period for each period. This is a rate of cost accumulation during construction. By the end of construction, the total accumulated real levelized cost is carried forward to subsequent periods.

**Earliest Availability (Period) –** This is a stochastic variable used by the model when the user specifies uncertain commercial availability.  The value of the stochastic variable indicates the earliest of that construction can begin.

**Regional Share –** Some units have a portion of their output dedicated to independent power producers (IPPs).  They are not owned by a regional utility.  They are not under firm contracts for regional use.  If this is the case, only part of the output accrues to the region.  The remaining energy will be supply to the wholesale power markets.  Otherwise, it does not benefit the region.

**Retirement mothball life (periods) –** This is the number of periods that a unit can be uneconomic before permanent decommissioning.  During this time, retirement is continuously evaluated.

**Retirement evaluation cost (RL $M/MWPeriod) –** During retirement evaluation, costs may accumulate.  The user specifies the cost here.  Costs are in real levelized millions of dollars per megawatt per period.  This cost appears in each period before decommissioning.  This cost disappears after decommissioning.

**Decommissioning cost (RL $M/MWPeriod) –** After the decision to decommission a unit is final, there are additional costs.  The user specifies that cost here.  Costs are in real levelized millions of dollars per megawatt per period.  This cost carries forward over the unit's remaining economic life.

**First Period Mothball Costs (RL $M/ MW/ Period) –** As described above, an early decision to mothball construction can save money.  If the user chooses this treatment, he specifies so through the integer in the first column.  He then enters in this column the cost, in real levelized millions of dollars per megawatt per period.  This cost carries forward until construction resumes.

**First Period Cancellation Costs (RL $M/ MW/ Period) –** This feature, described earlier, works in the same manner as **First Period Mothball Costs**, with one exception.  This cost carries forward for economic life of the unit.

**Generation technology –** If a resource is a candidate for capacity expansion or economic retirement, the type of technology (SCCT, CCCT, Wind, etc.) is required in this column.  Microsoft® Excel® data validation restricts the choice to a prescribed list.  The decision criterion needs this information to know which factors to consider.

**Status –** A unit's status can be "existing" or "new".  If it is "existing", it is a "surrogate" unit or a "simple" unit.  The construction and the decision criterion logic use this value to make appropriate choices.

**LT Fuel Price (Range name) –** This is the worksheet range name of the long-term fuel price forecast.  The decision criterion uses the forecast to determine economic viability.

**MTBR (weeks) –** The user can choose stochastic forced outages as an alternative to capability deration through the integer in the first column.  The model then needs both the forced outage rate (FOR) and the **Mean Time Before Repair** for this unit.  This is expressed in weeks.  See the discussion above for more information about modeling forced outages.

**FOR [0…1] –** The forced outage rate is required for all units.  If the user does not specify that the unit uses stochastic forced outages, the model will derate a unit's capability deterministically by the forced outage rate.  The value in this field should lie between zero and 1.0.  For example, if the forced outage rate is 5 percent, the value in this field is 0.05.

**Nameplate (MW) –** Existing units use this nameplate capacity.  It is subject to FOR and capacity adjustments.  New generation does not require this information.  New generation takes its capability directly from the decision cells at the top of the worksheet.  Typically, an optimizer controls these.

The model also uses this value, before adjustments, to calculate fixed O&M costs before any fixed O&M adjustment.  If there are no fixed O&M costs, it may be convenient to set this value to 1.0 and express capacity directly through capacity adjustments.

**Figure J-7:  Detail of options in previous figure**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | **West 1** |
| Option Selection (integer) | FOM (R $M/ MW/ period) | Late Constr Costs (RL $M/ MW/ Period^2) | Earliest Availability (Period) | Regional Share | Retirement mothball life (periods) | Retirement evaluation cost (RL $M/MWPeriod) | Decommisioning cost (RL $M/MWPeriod) | First Period Mothball Costs(RL $M/ MW/ Period) | First Period Cancellation Costs (RL $M/ MW/ Period^2) | Generation technology | Status | LT Fuel Price (Range name) | MTBR (weeks) | FOR [0...1] | Nameplate (MW) - required for cost calcs of existing units only |
| 264 | | | | | | | | | | CCCT | Existing Aggr | | 0.143 | 0.05 | 1.00 |

The following illustration (Figure J-8) shows how options interact.

The final Sixth Power Plan did not use some of the new features.   In particular, the GRAC suggested that a coal plant would never be retired for economic reasons.  Consequently, staff decided to retain existing coal plants in the region's portfolio of resources unless a study explicitly called for their removal.

Studies relied primarily on the model's new features for representing variable costs and stochastic forced outages.  Variable construction and FOM costs found extensive use.  Most of the variable costs were stochastic, and they contributed to modeling future uncertainty.

**Figure J-8:  Impact of Modeling Choices on Various Costs**

| end of study dollars | FOM Adjustment on original capacity | FOM Adjustment on modified capacity | VOM Adjustment | Capacity Adjustment | Construction Cost Adjustment on original capacity | Construction Cost Adjustment on modified capacity | Commercial Availability | Stochastic FOR | Escalation rates | | Use 2004 logic | FOM variable over study | FOM variable over study and over future | VOM variable over study | VOM variable over study and over futures | Capability variable over study | Capability variable over study and over futures | Construction Cost variable over study | Construction Cost variable over study and over fugure | Use Distinct Cost for Committed Construction | Use Internal Decision Criterion? | Stochastic Availability? | Use Distinct Cost for Mothballing in First Period? | Use Distinct Cost for Cancelling in First Period? | Initial capability Differs Each Game? | Spend early construction phase cash in first period | Permit Market Additions | Read construction costs from the internal array | After on-line | Economic Retirement Logic? | Stochastic FOR? |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sunken development cost ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | | | | | | | | | | X | | | | |
| development cost ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | | | | | | X | X | | | |
| mothball cost, first period variable ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| cancellation cost, first period variable ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| other mothball cost variable ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| other cancellation cost variable ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| mothball cost, first period fiXed ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| cancellation cost, first period fiXed ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| other mothball cost fiXed ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | X | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| other cancellation cost fiXed ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | X | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | | X | | | | |
| early construction costs ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | X | 1 | 1 | 1 | 1 | X | X | X | X | | | X | X | X | X | X | X | X | | | |
| late construction costs ($) | 1 | 1 | | X | X | X | 2 | 2 | X | | X | 1 | 1 | 1 | 1 | X | X | X | X | X | X | | | | | | | X | | | |
| FOM cost ($) | X | X | | X | | | | | | | | | | | | X | X | | | | | | X | X | X | X | | X | | X | X |
| VOM cost ($) | | | X | X | | | | 3 | | | | X | X | X | X | X | X | | | | | | X | X | X | X | | X | | X | X |
| fuel cost ($) | | | | X | | | | 3 | | | | | | | | X | X | | | | | | X | X | X | X | | X | | X | X |

1  Because FOM only affects operations, and in particular, only affects costs after construction,
this does not affect any construction costs.

2  Because these affect only operations, they do not affect any construction costs.

3 Stochast FOR affects variable cost, not fixed cost

Source: workbook "Relationship among variables.xls", worksheet "Sheet1"

## *RPS Modeling*

Chapter 9 of the Sixth Power Plan summarizes the renewable portfolio standards (RPS) adopted by the Pacific Northwest states.  The states of Washington, Oregon, and Montana have RPS requirements.  Typically, an RPS specifies that obligated utilities will meet a certain portion of their future energy needs with renewables.  The RPS gives a schedule that extends over several decades for meeting these targets.

There are several challenges in modeling RPS requirements.  Each state has different requirements and policies.  The obligation of utilities depends on their size, as measured by customers or load.  Also, utilities typically may “opt out” of their targets.  For example, some utilities can decline if meeting the standards would cause utility revenue requirements to exceed their requirements otherwise by 4 percent.

Representing RPS standards with the regional portfolio model (RPM) introduces several more problems.  The RPM uses 750 distinct regional load forecasts.  These regional load forecasts must somehow be allocated down to the utility level.  Moreover, the RPM can option wind and geothermal resources to reduce cost and risk to the region.  If these resources are present in a study, the model must coordinate the RPS acquisition of these resources.  The model must have rules for allocating any such new wind or geothermal energy back to individual states, if not utilities.  This energy presumably would apply toward their RPS targets.

There is a concern that the model might treat the RPS and non-RPS resources differently because of how construction risks are represented. Wind, geothermal, and other new technologies have detailed construction logic. This makes possible the accounting for the costs of delays, cancellation, and changing circumstances. The RPS resources, however, do not have this detail. A more aggregate approach is necessary. Also, because Council studies assume that states will always meet their RPS targets – or some fixed portion thereof – the question of construction uncertainty is moot. RPS resources therefore do not carry the cost associated with construction risks.

Another challenge in modeling RPS standards with the RPM is dealing with limits on the potential development of renewables. The Council has estimated the amount of cost-effective renewable potential in the region. This estimate exists for each type of renewable. The RPM needs rules to decide when renewables are used to meet RPS requirements. It must know whether their renewable energy credits (RECs) can and should be sold. It needs to know whether the required RPS development would exceed the regional potential and what should be done in that situation. This means anticipating where the renewables would come from and what they would cost. Ideally, the cost of RPS renewables would match the cost of non-RPS renewables having identical technology, location, and circumstance. In particular, RPS renewable construction would have the same cost uncertainty treatment.

## Representation

Early RPM studies allowed for RPS and non-RPS renewables serving energy needs simultaneously. That is, the model could option wind and geothermal resources and then meet any remaining RPS requirement with forced-in renewable energy. This made it possible to see whether renewables might be selected earlier or in greater quantity than the RPS targets.

It became evident, however, that the model never developed renewables more aggressively than the RPS rules required. In studies that assumed no RPS obligation, the renewables still enter the efficient frontier. Their schedules, however, do not keep up with their duty under an RPS.

Consequently, none of the final Plan scenarios have both RPS and non-RPS renewables in the same study. Either the RPS model is active and discretionary wind and geothermal are excluded, or the opposite is the case.

This policy has the benefit of solving some of the problems described above. Coordination is not necessary. There is no inconsistency due to construction risk – at least within a study – so one approach is not disadvantaged relative to the other. Allocation of non-RPS resources to individual states is not necessary. Not insignificant, the results of studies are easier to communicate.

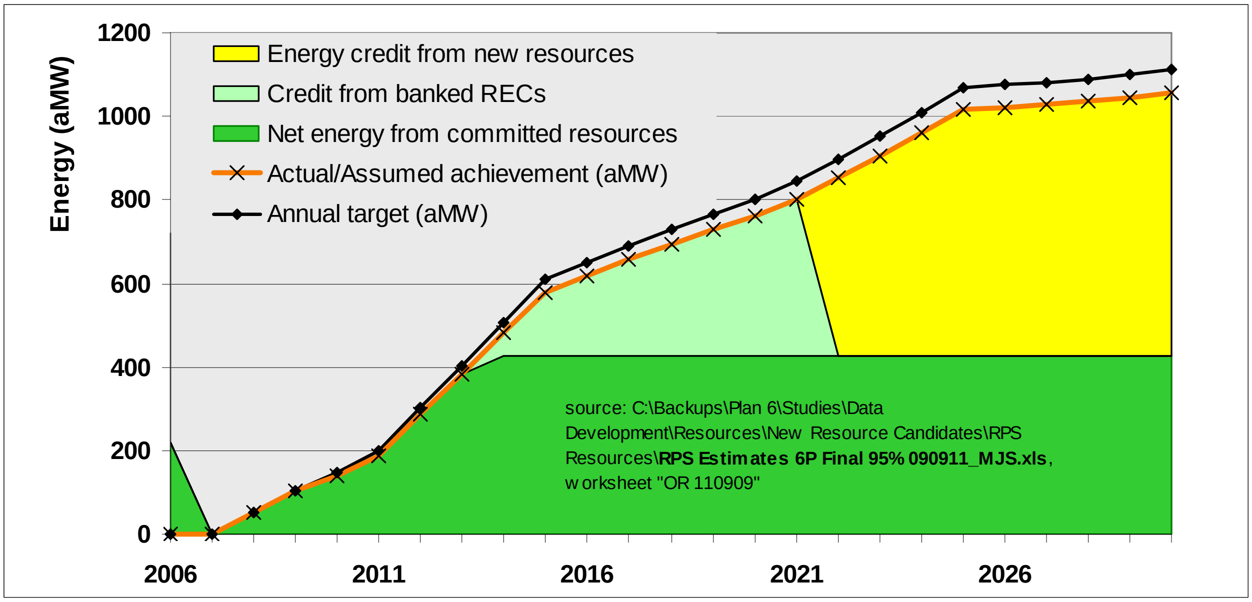
The logic in the RPM is based on an analysis that staff performed in the fall of 2008[10] and updated in fall of 2009[11]. The analysis estimates the amount of renewables already developed by each of the states. It identifies the obligated utilities and their respective RPS targets. The targets are reduced by 10 percent to reflect expectations that certain utilities will "opt out." The estimate of 10 percent is based on study of specific utility rates of load growth and their resource alternatives

10 See "RPS Estimates 100708.xls" and subsequently "RPS Estimates 021909.xls"

11 See "…\Plan 6\Studies\Data Development\Resources\New Resource Candidates\RPS Resources\Final Plan model\RPS Estimates 6P Final 95% 110909.xls"

for meeting demand.  Finally, it estimates the number of REC credits that each state has acquired to date.  The final forecast REC balance is shown in Figures J-9 through J-11, below.

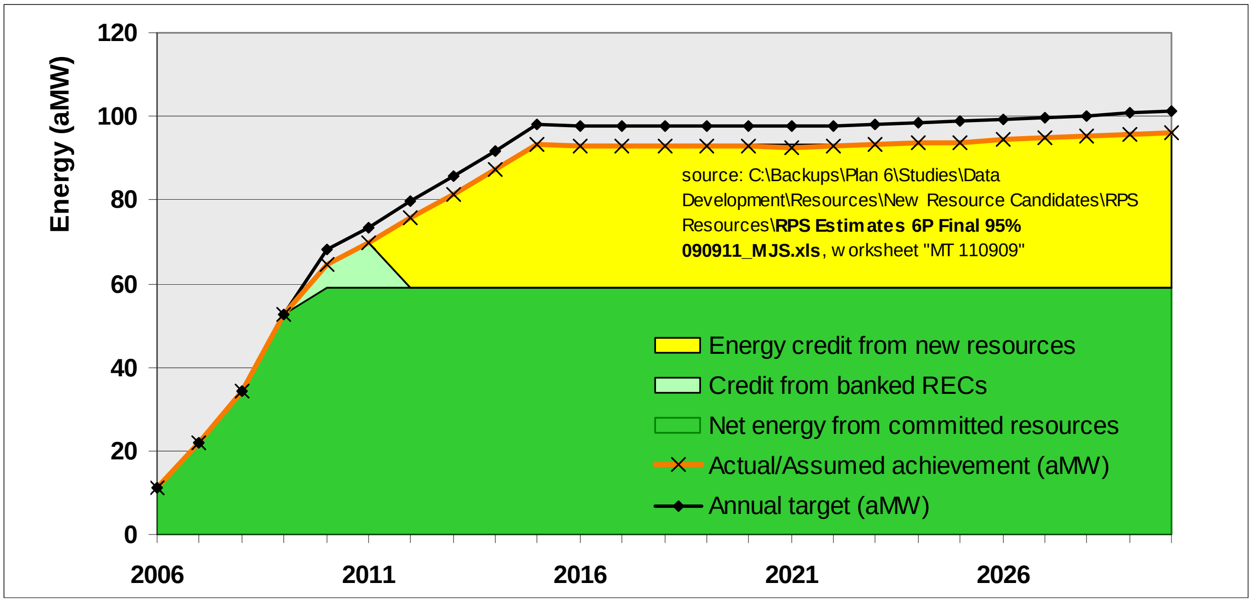
**Figure J-9:  Forecast REC Balance for the State of Oregon**




Some utilities are able to bank the REC credits they acquire by building renewables in advance of need.  The three states have different rules on how long a utility can bank its REC credits, however.  In Oregon, REC credits never expire.  In Washington, they expire after one year.  Montana permits utilities to bank their credits for two years.

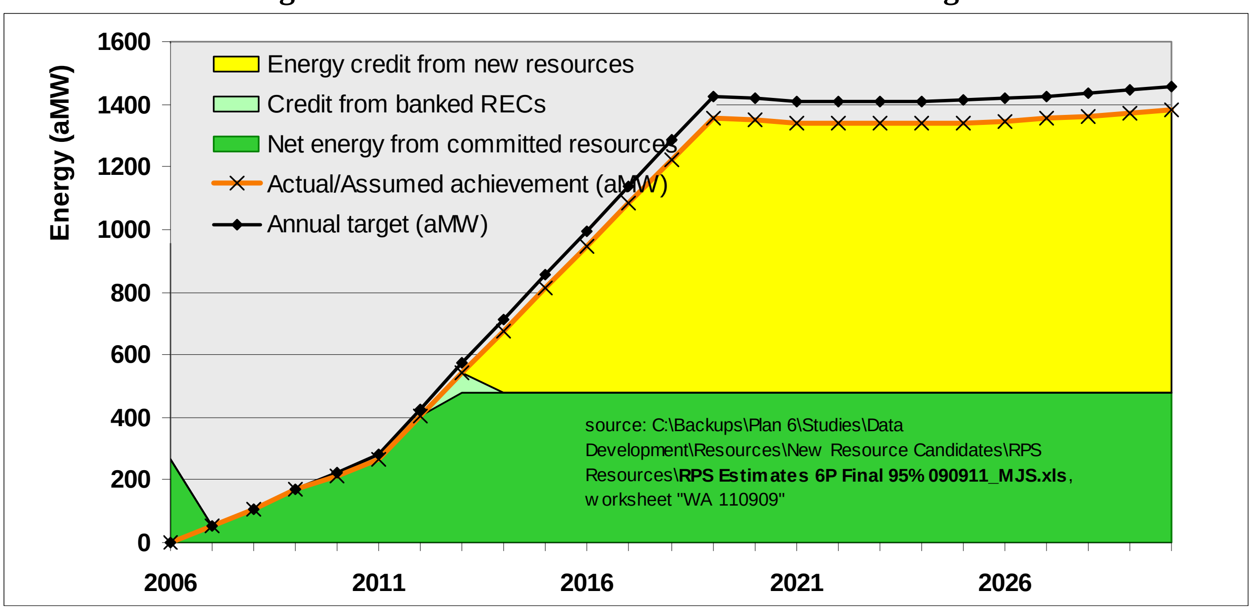
The RPM must track load, conservation, RPS requirement, and REC credit created, banked, expired, and used for each of the states.  It must track the cost for any renewables acquired to meet state targets after credits are exhausted.  The cost for new renewables sees the same adjustment for uncertainty, escalation, and so forth that costs of individual renewables in the model see.  The levelized cost is carried forward the same way that it is for non-RPS resources.  (The treatment for non-RPS resource costs is described in the section above, “More Detailed Specification of Construction Costs.”)

**Figure J-10: Forecast REC Balance for the State of Montana**




To estimate the gross RPS requirement for each state, the model uses a fixed estimate of the percentage of the region's load that each state's obligated utility load represents. This is about 3.3 percent for Montana, 27.2 percent for Oregon and 39.7 percent for Washington. The fraction of each state's obligated utility load that renewables must meet increases over time. Rules typically state the fraction for only three or four years, for example, 2015, 2020, and 2025. Straight line interpolation provides the model with estimates for the intervening years. For the first year in the RPM, hydro year ending August 2010, this interpolation yields 10 percent for Montana's obligated to load, 3 percent for Oregon's, and 2 percent for Washington's.

**Figure J-11: REC Balance for the State of Washington**




Given a future and plan, the model performs calculations period by period. For each period, results depend on achievements in prior periods and circumstances in the current period.

The period estimate begins with the gross RPS target for each state. This depends primarily on the level of electricity needs over the prior year (four hydro quarters) and conservation acquired. This is apportioned to each state as described above. The gross value is constrained to be non-decreasing. It is unlikely that a utility would ask for a smaller target due to, for example, short-term load variation. See Figure J-12 for the example of Montana's calculation.

The model then nets each state's gross RPS target, energy from existing renewables, and balance of banked RECs. According to the most recent study, Montana has about a 65 average megawatts of existing renewables; Oregon has about 465 average megawatts; and Washington has 520 average megawatts. The estimate of credits for each state is based on the Council's inventory of existing renewable projects.[12] In early years, state RPS requirements are minimal. Utilities with renewables therefore accumulate RECs subject to their state's banking rules. Figure J-13 displays the formulas.

**Figure J-12: Allocation of RPS Obligations**

| | O | P | Q | R | S | V | V |
|---|---|---|---|---|---|---|---|
| 697 | | | | | | | |
| 698 | | | | Sep - Nov 2009 | | Sep - Nov 2010 | |
| 699 | | | RPS resources | | | | |
| 700 | | Load, less conservation (MWa busbar) | | 21200 | | 21138 | m=-(V$331+V$333) |
| 701 | | MT obl ut requirement sales (MWa) | 3.1% | | | | |
| 702 | | | MT obl ut target (%) | 0% | | 10% | 10% |
| 703 | | OR obl ut requirement sales (MWa) | 26.9% | | | | |
| 704 | | | OR obl ut target (%) | 0% | | 3% | 3% |
| 705 | | WA obl ut requirement sales (MWa) | 40.3% | | | | |
| 706 | | | WA obl ut target (%) | 0% | | 2% | 2% |
| 707 | | Assumed Achievement | 95.0% | | | | |
| 708 | | | | | | | |
| 709 | | | MT obl ut target (MWa busbar) | 57.4 | | 61.4 | m=MAX(V$700*$Q$707*$Q$701*V702,R709) |
| 710 | | | MT resources (MWa busbar) | 65.0 | | 65.0 | m=R710 |
| 711 | | | MT credits remaining (MWa equivalent busbar) | 6.0 | | 13.6 | m=R710+R711-R709 |
| 712 | | | MT net requirement (MWa) | | | -17.2 | m=V709-V710-V711 |
| 713 | | | Sell RECs* | | | | |
| 714 | | | Carry forward credit* | | | 17.2 | m=MAX(0,-V712) |
| 715 | | | Buy Renewables | | | **0.0** | m=MAX(0,V712) |
| 716 | | | | | | | |
| 717 | | source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations**Resources\L813 for illustrating RPS.xls** | | | | | |

The net requirement may be either positive or negative. That is, the state may either need to acquire new RPS energy or not.

If the requirement is negative, the utilities could either sell the associated RECs or carry the credit forward. If the utility did not need the credits or the credits would expire before the utility could use the RECs, it would make more sense to sell the RECs. Oregon's credits never expire so there is little sense in Oregon utilities selling them. For Washington and Montana, the decision is not as clear.

Whether or not older RECs are sold or expire, however, has little significance for the question of acquiring new regional resources. First, any revenue from selling the RECs would only accrue before about 2011 for Washington and 2008 for Montana. RECs acquired after these date would have value meeting RPS requirements and presumably be retained. The amount of revenue from two years of REC sales in Washington would be relatively small. Second, the revenues are practically "sunk." The effect of expected conservation, a factor that can affect REC requirements, has already been included in the forecasts for RPS requirement in Figures J-9 through J-11. Variation in forecast conservation energy is insignificant over the first two years of the simulation. Consequently, the revenues would be the same for all plans in each future.

12 …\Plan 6\Studies\Data Development\Resources\Existing Non-Hydro\091018 Database system\091018 Original Sources\Existing Projects 101809.xls

For accessing the impact on the region's need for new resource, therefore, the model can retain all RECs for utilities, rather than selling them. Old RECs in Montana and Washington may have been sold instead. Recently acquired RECs have not expired and would defer RPS energy. If retained, these RECs would have significant value in those states. Therefore, they likely would be retained.

If the net requirement is positive, on the other hand, the model adds the energy and cost of new RPS resources. In the example of Montana, the need for new RPS resource appears in row 718 of Figure J-13.

Finally, the energy and cost of new RPS resources across all three states is summed up in rows 738 to 744 of Figure J-13. The estimate of regional gross cost for the RPS resources is produced using an Excel formula for that purpose, dfuncRPSCost(). The formula assures that costs match those for wind generation exactly. The cost includes uncertainty effects for construction and for production tax credits. It also levelizes and transfers forward of the levelized cost. The worksheet calculates the gross value of the energy in row 744 of Figure J-13.

**Figure J-13: Detailed RPS Requirements Calculation**

| | N | O | P | Q | R | S | V | W | X |
|---|---|---|---|---|---|---|---|---|---|
| 710 | | | | | Sep - Nov 2009 | | Sep - Nov 2010 | | |
| 711 | | | | | | | | | |
| 712 | | | | MT obl ut target (MWa busbar) | 57.4 | | 61.4 | m=MAX(V$700*$Q$707*$Q$701*V702,R709) | |
| 713 | | | | MT resources (MWa busbar) | 65.0 | | 65.0 | m=R710 | |
| 714 | | | | MT credits remaining (MWa equivalent busbar) | 6.0 | | 13.6 | m=R710+R711-R709 | |
| 715 | | | | MT net requirement (MWa) | | | -17.2 | m=V709-V710-V711 | |
| 716 | | | | Sell RECs* | | | | | |
| 717 | | | | Carry forward credit* | | | 17.2 | m=MAX(0,-V712) | |
| 718 | | | | Buy Renewables | | | **0.0** | m=MAX(0,V712) | |
| 719 | | | | | | | | | |
| 720 | | | | OR obl ut target (MWa busbar) | 113.6 | | 143.6 | m=MAX(V$700*$Q$707*$Q$703*V704,R717) | |
| 721 | | | | OR resources (MWa busbar) | 465.4 | | 465.4 | m=R718 | |
| 722 | | | | OR credits remaining (MWa) | 1053.4 | | 1405.3 | m=R718+R719-R717 | |
| 723 | | | | OR net requirement (MWa) | | | -1727.1 | m=V717-V718-V719 | |
| 724 | | | | Sell RECs* | | | | | |
| 725 | | | | Carry forward credit* | | | 1727.1 | m=MAX(0,-V720) | |
| 726 | | | | Buy Renewables | | | **0.0** | m=MAX(0,V720) | |
| 727 | | | | | | | | | |
| 728 | | | | WA obl ut target (MWa busbar) | 186.0 | | 194.2 | m=MAX(V$700*$Q$707*$Q$705*V706,R725) | |
| 729 | | | | WA resources (MWa busbar) | 520.3 | | 520.3 | m=R726 | |
| 730 | | | | WA credits remaining (MWa) | 607.3 | | 941.5 | m=R726+R727-R725 | |
| 731 | | | | WA net requirement (MWa) | | | -1267.6 | m=V725-V726-V727 | |
| 732 | | | | Sell RECs* | | | | | |
| 733 | | | | Carry forward credit* | 941.5 | m=R727+R726-R725 | 1267.6 | m=MAX(0,-V728) | |
| 734 | | | | Buy Renewables | | | **0.0** | m=MAX(0,V728) | |
| 735 | | | | | | | | | |
| 736 | | | | | | | | | |
| 737 | | | | | | | | | |
| 738 | | | | **Regional net requirement (MWa busbar)** | | | **0.0** | **m=V715+V723+V731** | |
| 739 | | | **Gross Nominal Requirements (MWa** busbar after achievements) | | 357.0 | **m=R725+R717+R709** | 399.2 | **m=V725+V717+V709** | |
| 740 | | | **Gross Nominal Requirements (MWh** busbar after achievements) | | 0 | m=IF(ISBLANK(R$733),Q735,R734*2016) | 804866.8 | m=IF(ISBLANK(V733),U735,V734*2016) | |
| 741 | | | **Net regional energy on- and off-peak (MWh** busbar after achievements) | | 0.0 | m=IF(ISBLANK(R$733),Q736,R733*2016) | 0.0 | m=IF(ISBLANK(V733),U736,V733*2016) | |
| 742 | | | **Net regional energy on-peak (MWh** busbar after achievements) | | 0.0 | m=R736*1152/2016 | 0.0 | m=V736*1152/2016 | |
| 743 | | | | Regional total gross cost ($M) | 0.0 | m=dfuncRPSCost(Q55,Q736,R736,R106) | 0.0 | m=dfuncRPSCost(U55,U736,V736,V106) | |
| 744 | | | | Regional on- and off-peak gross value($M) | 0.0 | m=-R736*R$276/1000000 | 0.0 | m=-V736*V$276/1000000 | |
| 745 | | | | | | | | | |
| 746 | | | source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations**Resources\L813 for illustrating RPS.xls** | | | | | | |
| 747 | | | | | | | | | |

## *Perpetuity Factor and End Effects*

This section describes an adjustment to costs to reflect the impact of irreversible circumstances, such as a carbon penalty, on the economic value of power plants. The model reports and uses NPV costs that have this "perpetuity" adjustment. The section describes the derivation and implementation of the adjustment.

The RPM uses real-levelized costs for power plant capital costs. Appendix L of the Fifth Power Plan explains the decision to use real-levelized costs. Briefly, levelizing spreads the construction cost of the plant evenly over its life. Spreading the cost matches the cost of construction with whatever value the plant produces.

It is typical to assume that plant cost and value within the time window of the study will represent those beyond the study horizon. For example, if a plant is profitable during the study, we have no basis for assuming it would not be after the study horizon. If a plant is more profitable than an alternative during the study period, we expect it would be after the horizon.

This approach saves the study from complicated and burdensome calculations. If costs were to resemble cash flow instead of being level, the timing of the cash flows becomes an issue. Cash spent for construction makes an investment look unattractive in early years. Studies would have to capture cost and value over the economic life of a plant to be representative. If a study had more than one resource, the study would have to capture these “life cycle” costs for resources with different economic lives. The lifetimes also are rarely matched, even if they are of equal length. Dealing with all these concerns requires a special “end effect” calculation. The end effect calculation, moreover, brings issues of its own. Levelizing eliminates all this.

If a carbon penalty appears during a study, however, the assumption underlying levelizing becomes questionable. Economics beyond the study horizon will more likely resemble that ***subsequent*** to the arrival of the penalty. Consider a carbon penalty imposed during the last two years of a study. A plant placed into service five years before the end of the study carries the penalty for 2/5 of its life ***in the study***. If the plant has a 20-year life, however, the penalty will in fact apply for the remaining 15 years of its life, or 18/20 of its lifetime.

As this section explains, the RPM model addresses this problem by extending all the costs in the study after the point in time when a carbon penalty appears. To allow for resources of unequal economic lifetimes, the model extends the costs in perpetuity. Portfolios can then be compared fairly on the basis of economic cost and risk. Users must take care, however, in the interpreting other measures, such as revenue requirements and rates, derived from NPV costs.

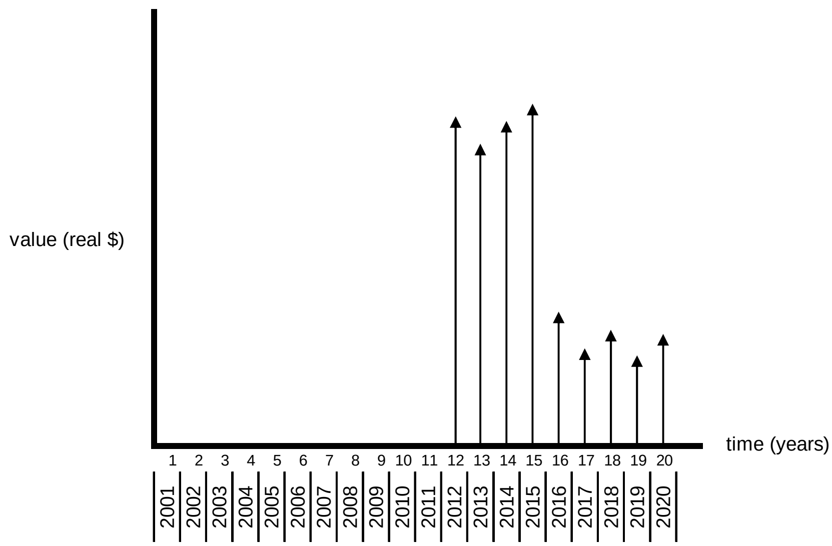
## Example Problem

A coal plant goes into service in 2012. In 2016, a carbon penalty arrives. Figure J-14 illustrates the gross value of this power plant over time.

Figure J-14 is an illustration of a 20-year study that begins in 2001. The arrows correspond to dollar amounts of the annual value of energy in the market net of fuel and variable operating costs. (For the time being, ignore the fixed costs associated with this power plant.) After the carbon penalty appears, the gross value of this power plant goes down because the cost of fuel, including the carbon penalty, goes up.

The present value of these cash flows may overstate the value of the plant relative to alternatives with lower carbon emissions. The present value would not capture the cost of the carbon penalty over the remaining economic life of the plant. If the economics of the plant during the 20 year study, that is, between the years 2012 and 2020, are not representative of its lifecycle economics, a bad decision may result. There are alternatives to the coal plant for meeting regional energy requirements. Consequently, even a relatively small shift in the value may give rise to an improper ranking of alternatives.

**Figure J-14: Study Gross Value for Coal Plant**

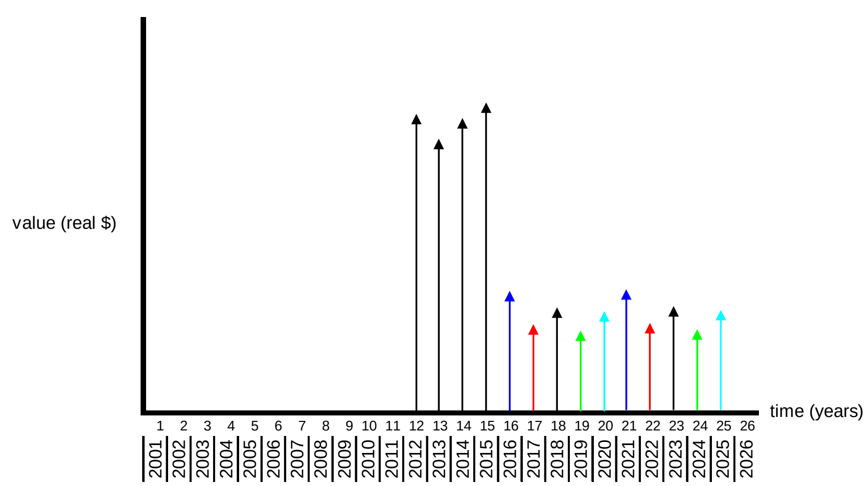



source: …\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

## RPM Solution

One rather natural way to capture the economics of this resource beyond the study is to use the periods after the arrival of the carbon penalty. In Figure J-15, the pattern of values after the carbon penalty appears simply repeats. The values are colored in this illustration to emphasize their cyclical nature.

**Figure J-15: Extension of Penalized Values**




source: …\Plan 6\Studies\Model Development\CO2 tax end effect\illustrations 100303.xls

The present value relationship between the cash flow in 2022 and that in 2017 is given in Equation J-1. The fifth power of the discount factor in the second term arises from the period of the cycle of values. Because the event occurs in period E and the study has S periods, the cycle length is equal to S-E+1, as the last term states. The same relationship holds between the cash flow in 2023 and 2018, 2024 and 2019, and so forth.

**Equation J-1**

$$V_{2022} = \frac{1}{(1+d)^5} V_{2017} = \frac{1}{(1+d)^{(S-E+1)}} V_{2017}$$

where

$V_{2017}$ is the present value of gross value in 2017

$V_{2022}$ is the present value of gross value in 2022

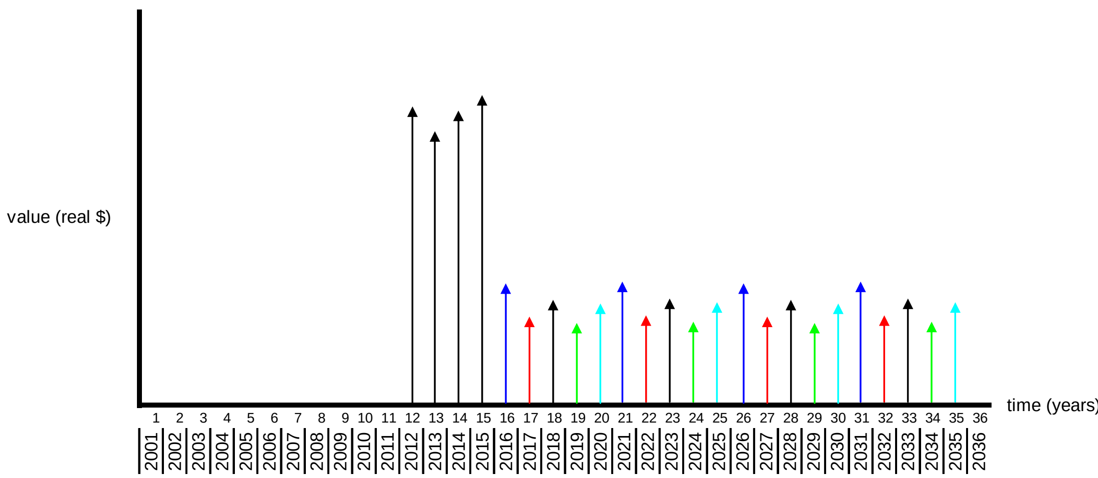
$d$ is the discount rate

$S$ is the last year of the study

$E$ is the year in which the carbon penalty arrives

By repeating the cycle of values, the value over the plant's remaining life is obtained.  Assume the plant' economic life ends after 2035.  Figure J-16, therefore, shows the extension of the cycle of values through that year.

**Figure J-16:  Extension of Values over Lifetime**

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Now the relationship of the present value of the cash flow in 2027 to that in 2022 is the same as that between the cash flow in 2022 and 2017, namely Equation J-1.  Let the variable W denote the conversion factor in Equation J-1.  The present value in 2017 of cash flows in 2017, 2022, 2027 and 2032 is then Equation J-2.

**Equation J-2**

$$V_{2017} + V_{2017} \times W + V_{2017} \times W^2 + V_{2017} \times W^3$$
$$= V_{2017} \times (1 + W + W^2 + W^3)$$

Again, the same relationship holds for corresponding subsequences beginning in 2016, 2018, 2019, and 2020.

Equation J-3 simply states the present value to 2001 of the terms from 2016 to 2020.

**Equation J-3**

$$
\begin{aligned}
&NPV_{2001}(V_{2016},\cdots V_{2020}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} + \frac{V_{2017}}{(1+d)^{(2017-2001)}} + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}}
\end{aligned}
$$

Denoting $(1+W+W^2+W^3)$ by G, the present value of cash flows in Figure J-16 from 2016 through 2035 back to the beginning of the study is Equation J-4

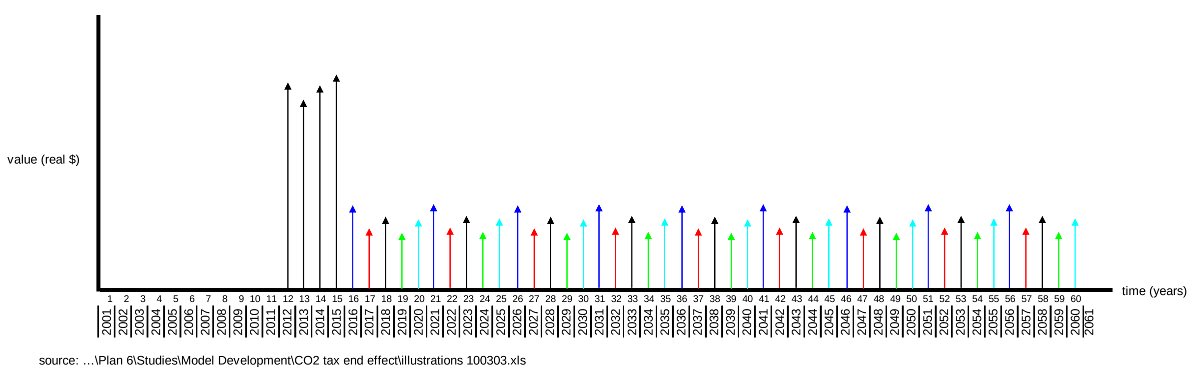
**Equation J-4**

$$
\begin{aligned}
&NPV_{2001}(V_{2016},\cdots V_{2035}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times G + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times G + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times G \\
&= NPV_{2001}(V_{2016},\cdots V_{2020}) \times G
\end{aligned}
$$

The effect associated with carbon penalty is now reduced to a single multiplier. The multiplier applies to the present value of cash flows in the study subsequent to the carbon penalty.

This solution, however, does not address the problem if a power plant does not have exactly this economic life time or if there are alternative resources with distinct economic lives. One solution to this is to extend the cycle and the evaluation horizon indefinitely. That is, mathematically it is meaningful to extend the cycle of values to infinity. (See Figure J-17.)

**Figure J-17: Indefinite Extension**




How do we interpret the extension of cash flows associated with our coal plant beyond its economic life? It is customary to assume replacement in kind. From a present value standpoint, contributions beyond the economic life of a typical power plant from replacements are small.

The sum of an infinite series of powers of a variable is called the geometric series. (See Equation J-5):

**Equation J-5**

$$
\sum_{i=0}^{\infty} x^i = 1 + x + x^2 + x^3 + \cdots = \frac{1}{(1-x)}, \quad 0 \le x < 1
$$

The adjustment to the net present value of cash flows after the carbon penalty is therefore multiplication by a fixed constant (See Equation J-6).

**Equation J-6**

$$\begin{aligned} &NPV_{2001}(V_{2016}, V_{2017}, \cdots, \infty) \\ &= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times \Pi + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times \Pi + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times \Pi \\ &= NPV_{2001}(V_{2016}, \cdots V_{2020}) \times \Pi \\ &\text{where } \Pi \text{ is the "perpetuity factor," } \frac{1}{1\text{-}W} = \frac{1}{1\text{-}\left(1+d\right)^{(E-S-1)}} \end{aligned}$$

It would be convenient to replace the net present value of cash flows over the 20-year study with a similar formula that includes the extension to perpetuity. To do so, start with the general statement in Equation J-7:

**Equation J-7**

$$NPV_{2001}(V_{2016}, \cdots V_{2020}) = NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})$$

Equation J-7 replaces the term $NPV_{2001}(V_{2016}, \ldots, V_{2020})$ in Equation J-6 with the difference between two present values that both begin with the first cash flow of the study. Then $NPV_{2001}(V_{2001}, \ldots, \infty)$ is the left-hand side of Equation J-6 plus another present term, $NPV_{2001}(V_{2001}, \ldots, V_{2015})$, that begins with the first cash flow of the study.

**Equation J-8**

$$\begin{aligned} NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) = {} & NPV_{2001}(V_{2001}, \cdots V_{2015}) + \\ & \left[NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})\right] \times \Pi \\ & = \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + (1-\Pi) \times NPV_{2001}(V_{2001}, \cdots V_{2015}) \end{aligned}$$

The Excel OFFSET() function can make this formula more flexible. It permits the user to begin the perpetuity sample period in any year (Equation J-9). If the period that the carbon penalty arrives changes, the model need only update the value of variable ***E*** in Equation J-9.

**Equation J-9**

$$\begin{aligned} NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) = {} & \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + \\ & (1-\Pi) \times NPV_{2001}\left(\text{Offset}\left(\left[V_{2001}, \cdots V_{2020}\right], 0, 0, 1, E-1\right)\right) \end{aligned}$$

This modification of the standard NPV formula applies to every cash flow in the model. Because the model uses valuation costing, it must be applied therefore to the cost of load valued in the power market, as well as to all fixed costs.

To avoid burdening the reader with even more technical explanation, suffice it to say that there are problems with tying the perpetuity sample period to the arrival of the carbon penalty. The perpetuity sample period is the period ***E*** above through the end of the study. All of the modeling up to the final model tied the perpetuity sample period to the arrival of the carbon penalty.

The final version of the model uses a fixed sample period, the last two years of the study. With this approach, power plants are prohibited from completing construction in the last two years. The carbon penalty is likewise forced to occur before the perpetuity sample period or not at all. These constraints are largely unnecessary, however. In the unconstrained model, no plant completes construction in the last two years. Only 0.5 percent of the futures have a carbon penalty that arrives in the last two years.

It should be noted that the approach adopted for the final Plan may overstate the requirement for combustion turbine licensed and permitted in the out years. The least-risk resource portfolio from the Carbon Risk scenario calls for nine 415 MW units by the end of the study. In the draft plan, the portfolio from the same point on the efficient frontier of the Carbon Risk scenario called for two combined-cycle combustion turbines by the end of the plan. Studies without the perpetuity adjustment called for even fewer combined-cycle combustion turbines by the end of the plan. (In other respects, specifically the market adders for conservation and the value of renewables, the results are nearly identical.) There is reason to believe the perpetuity adjustment is responsible for these differences. If there are unsustainable excursions in electricity price or in other uncertainties in the perpetuity sample period, those excursions will have disproportionate effect on NPV total system cost.

Given these observations, prudence favors the lower estimate of permits for the combustion turbines. The perpetuity adjustment arose from a specific perceived problem. The problem was the treatment of economics for coal plants, and other fossil fuel plants, where carbon penalties arise after the coal plant is in service. This situation, however, is virtually absent in the final plan. The Council's carbon penalty probability distribution makes it unlikely for new fossil-fired plants to come into service before the carbon penalty. Across the 750 futures in the least-risk Carbon Risk resource portfolio, it never happens to a combined-cycle combustion turbine. It happens in only 3.1 percent of the futures to simple-cycle combustion turbines[13]. The Council excludes conventional coal plants as new resource candidates. Under these circumstances, modeling ***without*** the perpetuity factor adjustment probably gives us the fairest assessment of risk and of the need for new resources. These considerations, however, have little immediate significance. The earliest regional construction that the model calls for begins in December 2015, with ground breaking for two 85 megawatt simple-cycle combustion turbines.

## *Modeling Energy-Limited Resources*

Chapter 5, ***Demand Response***, describes resources that run only a brief number of hours each year. The number ranges from 40 to 100 hours per year. These resources were not in the Fifth Power Plan. To model this kind of resource, new algorithms were necessary. This section summarizes the new technique.

Appendix L of the Fifth Power Plan describes how the model uses statistical distributions of hourly fuel and electricity market prices to estimate dispatchable power plant energy production and value. The section entitled, ***Thermal Generation***, beginning on page L-26 of Appendix L, is prerequisite to understanding this discussion.

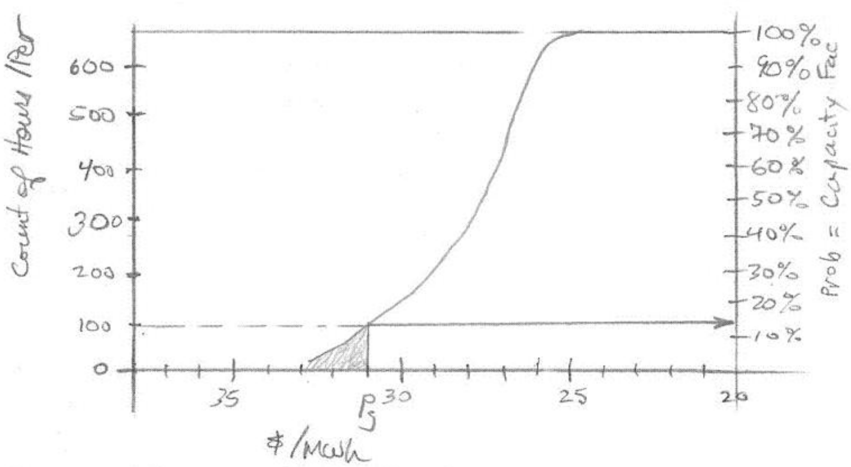
13 Source: "…\Plan 6\Studies\L813\Event statistics 091223.xls". See also "…\Plan 6\Studies\Model Development\CO2 tax end effect\Frequency of carbon penalty and unit completion.xls" for analogous draft Plan resource portfolio information.

Figure J-18 presents an example that will illustrate the algorithm. The curve in this figure is a price duration curve for wholesale power prices over some period. For this example, the period will be one month. Assume a particular generating unit exists that dispatches at electricity prices above $31 per megawatt hour. That is, it has fuel price and heat rate that makes dispatch profitable at that price. The capacity factor of the unit corresponds to the number of hours of operation out of the number of hours in the month. According to the figure, this would be about 15 percent of the hours. Whenever it is cost effective to generate, the economic choice is to generate at full capacity. Thus the capacity factor and the unit capacity yield amount of energy produced. The value of this generation is the shaded area to the left of the dispatch price.

Consider now a different electricity price duration curve, illustrated in Figure J-19, resulting from higher power prices. Given the same dispatch price, the figure suggests the unit would now dispatch in 60 percent of the hours or about 400 hours. In Figure J-19, the dotted line passing though the point on the price duration curve directly above the dispatch price now hits 60% on the right.

With the higher electricity prices, what would happen if the unit could run no more than 200 hours in a month? This constraint corresponds to a 27 percent capacity factor. It is represented by the solid horizontal line in Figure J-19. In this case, the economic choice for this unit is to run over that 200 highest-value hours. This creates the value corresponding to the shaded area in Figure J-20 beneath the horizontal line and to the left of the dispatch price, just as before.

**Figure J-18: Price of Fuel Determines Energy Production**




To calculate the value of the generation is to estimate area to the left of the dispatch price in the model. Start by finding the price $p_g$* that would give the same energy-limited capacity factor if the hours of operation were not constrained. This price appears in Figure J-21.

**Figure J-19: Constraint on Energy**

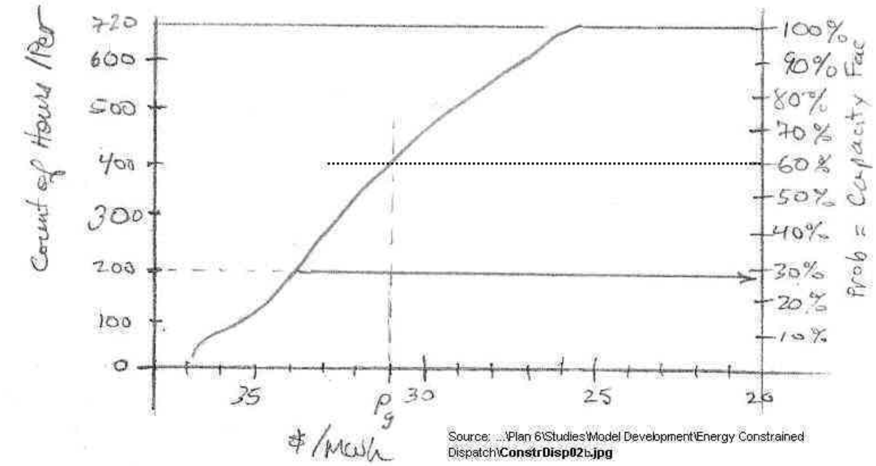



**Figure J-20: Value Produced**

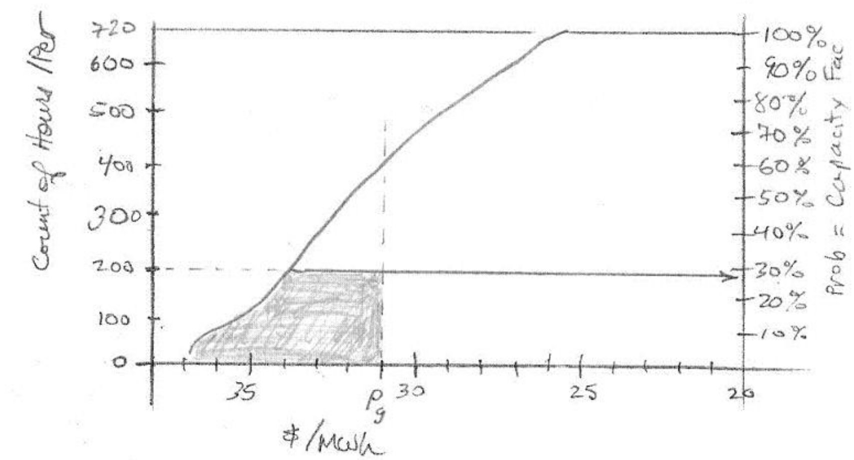
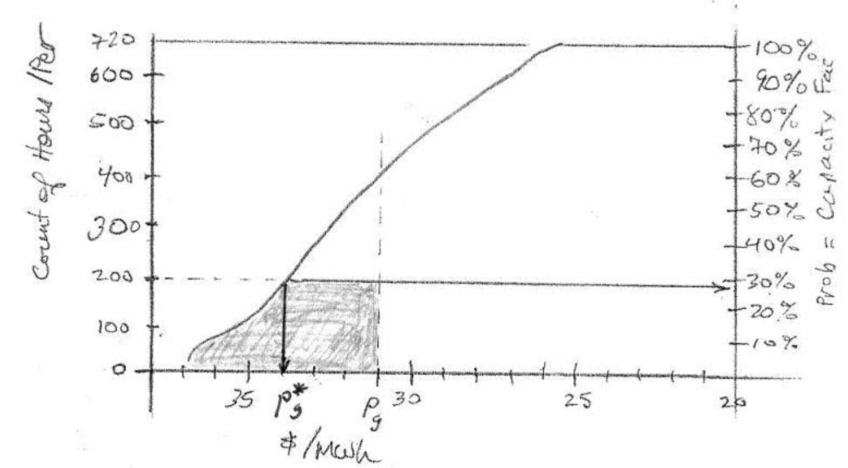



**Figure J-21: Fuel Price Corresponding to Energy Constraint**



It turns out that if the energy-limited capacity factor is fixed, finding $\boldsymbol{p_s}^*$ is straightforward. It is also robust. The model can estimate the relationship once, at the beginning of the simulation, and quickly update the value of $\boldsymbol{p_s}^*$ for each calculation.

In application, the model simply compares $\boldsymbol{p_s}^*$ against the price of fuel $\boldsymbol{p_g}$ in that period. If $\boldsymbol{p_s}^*$ is **greater than** the price of fuel, the hours and energy are constrained and the model uses $\boldsymbol{p_s}^*$ to determine the generation and value of the energy. If $\boldsymbol{p_s}^*$ is **less than** the price of fuel, the hours and energy are unconstrained. The model then uses the price of fuel $\boldsymbol{p_g}$ to determine energy generation and value as it normally would in the unconstrained case.

Estimating the area to the left of the dispatch price $\boldsymbol{p_g}$ in the constrained case is also simple. The model routinely calculates the area to the left of dispatch prices in the unconstrained case. It has efficient ways to do that. If can therefore quickly calculate the area to the left of $\boldsymbol{p_s}^*$. The area corresponding to value in the constrained case then is the area to the left of $\boldsymbol{p_s}^*$, augmented by a rectangle of value between $\boldsymbol{p_s}^*$ and $\boldsymbol{p_g}$. The height of the rectangle is the number of hours constrained. The area of the rectangle is therefore also known.

## *Quantitative Risk Analysis*

Studies of the RPM results provide insights into the economic risk for the region. The following summarizes findings about the correlation of and sensitivity of system cost to sources of uncertainty.

The term "correlation" may require explanation. It refers to the strength of the relationship between the uncertainty and cost. For example, a plot of the time that students spent studying a topic and their scores on their test would not show a straight-line relationship. Instead, there would be a cloud of points. The correlation is a measure of how tightly the cloud clusters around the trend line. It tells us how much the variable "study" explains the result ("test score"). The sensitivity, on the other hand, is the slope of the line. Correlation is an aspect of the data that is largely independent of sensitivity. In this study, the t-statistic is the primary measure of correlation.

The following describes the explanatory variables in this study. The selection of these variables is the result of examining many models. The value of $R^2$ measures of much variation the model explains. The strategy for selecting variables is to increase $R^2$ until other statistical tests indicate the model has too many variables.

**Cost –** The dependent variable ($M) representing all variable costs of the existing and new system. The dependent variable does not show up explicitly in the results. It is the variable against which the other variables are regressed. The analysis uses quarterly cost from the RPM. Separate studies are performed for on- and off-peak costs.

**CO2_Penalty –** The carbon penalty ($2006per ton **e**$CO_2$) discussed throughout the Plan.

**NGP_East** ($2006/MMBTU) – The cost of natural gas delivered to power plants east of the Cascades, where most of recent capacity additions have been made and future additions are likely.

**ELP –** Electricity price ($2006 per megawatt-hour), east of the Cascades, where much of the generation resides. Electricity price on peak is denoted **ELP_NP**; electricity price off peak is denoted **ELP_FP**

**Position –** System energy load requirements in terawatt hours (TWh = MWh x $10^6$). These particular elements of load requirements, however, are insensitive to power market prices. Position on peak is denoted **Position_NP**; position off peak is denoted **Position _FP**

Position is

- ✓ Non-DSI power load
- ✓ DSI power load

less

- ✓ conservation
- ✓ RPS resources (wind and geothermal generation)
- ✓ must run resources
- ✓ contracts
- ✓ hydrogeneration

Position is a measure of the system to which the remaining system (generation and imports/exports) must respond through power market price signals.

Position is a useful variable because loads, hydrogeneration, and the other variable are reduced to this value. To understand how cost responds to any of these, look to the role of this single variable.

**Market –** The product ($M) of market power price **ELP** and of **Position**. This variable tells us how much combinations of high prices and deficits add to cost. If low prices and surpluses contribute to cost, this variable is also significant. This is called an interaction term. The value of the Market variable on peak is denoted Market_NP; the value of the Market variable off peak is denoted Market_FP;

Adding the interaction term to the model permits the model to reflect the movement of these variables in the same direction. Consider, for a moment, the following product:

$$\left(Q-\overline{Q}\right)\left(p_e-\overline{p_e}\right)$$

where

$Q$ is the position (MWa)

$\overline{Q}$ is the average position

$p_e$ is the price of electricity

$\overline{p_e}$ is the average price of electricity

If $Q$ and $p_e$ ***both move below*** their average, each term is negative and the product is positive. Similarly, if $Q$ and $p_e$ ***both move above*** their average, the product is again positive. The product is negative only when the two variables move in opposite directions. If we included this product in the regression, therefore, its significance would indicate that the ***coordinated movement*** of the variables explains higher cost.

Table J-3 is the result of the regression analysis. There are separate analyses for on- and off-peak costs. The multiple $R^2$ for the on-peak model is over 95 percent; it is about 89.4 percent for the off-peak model. There is no indication of surplus variables[14]. All of the variables are highly significant, with that for $CO_2$ penalty standing out.

**Table J-3: Regression Model Coefficients**

on-peak model

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 62.63 | 1.49 | 42.15 | 0.00 | 59.71 | 65.54 | 59.71 | 65.54 |
| Position_NP | 22.02 | 0.17 | 126.49 | 0.00 | 21.67 | 22.36 | 21.67 | 22.36 |
| ELP_NP | (8.23) | 0.03 | (314.43) | 0.00 | (8.28) | (8.18) | (8.28) | (8.18) |
| Market_NP | 0.80 | 0.00 | 309.99 | 0.00 | 0.80 | 0.81 | 0.80 | 0.81 |
| CO2_Penalty | 7.59 | 0.02 | 465.22 | 0.00 | 7.56 | 7.62 | 7.56 | 7.62 |
| NGP_East | 31.93 | 0.16 | 203.77 | 0.00 | 31.63 | 32.24 | 31.63 | 32.24 |

source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Regression Analysis of L813 Costs**Regression_on_cost_L813LC_100228_00.xls, wksht "NP_Variables"**

off-peak model

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 7.64 | 0.81 | 9.48 | 0.00 | 6.06 | 9.22 | 6.06 | 9.22 |
| Position_FP | 17.40 | 0.15 | 115.52 | 0.00 | 17.10 | 17.69 | 17.10 | 17.69 |
| ELP_FP | (1.62) | 0.02 | (89.23) | 0.00 | (1.66) | (1.59) | (1.66) | (1.59) |
| Market_FP | 0.59 | 0.00 | 189.85 | 0.00 | 0.59 | 0.60 | 0.59 | 0.60 |
| CO2_Penalty | 3.18 | 0.01 | 237.33 | 0.00 | 3.16 | 3.21 | 3.16 | 3.21 |
| NGP_East | 10.40 | 0.11 | 94.40 | 0.00 | 10.18 | 10.61 | 10.18 | 10.61 |

source: C:\Backups\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Regression Analysis of L813 Costs**Regression_on_cost_L813LC_100228_00.xls, wksht "FP_Variables"**

Some care is necessary in interpreting the coefficients. Their size depends on the chosen units. That is, if a variable for price is in cents rather dollars, the coefficient will be 100 times larger.

This table reveals the following. Every dollar increase in natural gas prices causes regional costs to go up $39.42 million (22.02+17.40) per standard quarter[15]. For every dollar per ton $CO_2$ carbon penalty the region faces, cost increases $10.77 million (7.59+3.18) per standard quarter. Every dollar per megawatt-hour that wholesale electricity prices go up, regional cost declines by $9.85 million (8.23+1.62) per standard quarter. This is consistent with the observation that the region is modestly surplus over the study period. It does not take into account, however, the interaction term, Position, and therefore represents change only if Position were 0.0.

Position is the product of net requirement (loads – resources) and power price. The net requirement, however, does not include dispatchable resources. For each 1000 MW that a system deficit increases relative to this measure, cost rises $1.43 million ((1000*1152*0.80+1000*864*0.59)/1,000,000) per standard quarter for each dollar per megawatt-hour that power market prices increase. They would *also* rise by this amount if market prices fell when the region was surplus an equivalent amount.

14 For the on-peak model, R Squared = Adjusted R Squared = 90.9%; for the off-peak model, R Squared = Adjusted R Squared = 79.9%

15 The standard quarters that the model uses has 12 weeks or roughly 92 percent of the hours in a calendar quarter. A standard quarter has 1152 hours on peak and 864 off peak. Upward adjustment is necessary for comparison with actual costs.

This brief analysis underscores the potential for market exposure and other uncertainties to affect cost and cost volatility. For even a modest firm deficit, the contribution from the interaction term Position dominates the wholesale electricity price effect. The next section illustrates these finding with specific examples.

## *Illustration with Selected Futures*

This section presents two futures that have the potential for large risk under the Council recommended resource portfolio. The first is the most expensive future. It shows the risk of not anticipating large power requirements. The second future is one selected to show risk for the centerpiece of the Sixth Power Plan, conservation. It features low electricity prices and low requirements, and it results in a large surplus. Finally, an example features the same future as the last one, but where there is no conservation. Instead, the risk of inadequate resources has been met with combustion turbines.

The plan chosen for the first two illustrations is the least-risk plan from the Carbon Risk scenario. Chapter 9 introduces the ideas of a feasibility space and its efficient frontier. The efficient frontier for in the Carbon Risk scenario appears in Figure J-22. The schedule for the earliest construction of each resource in this plan appears in Figure J-23.

**Figure J-22: The Efficient Frontier**

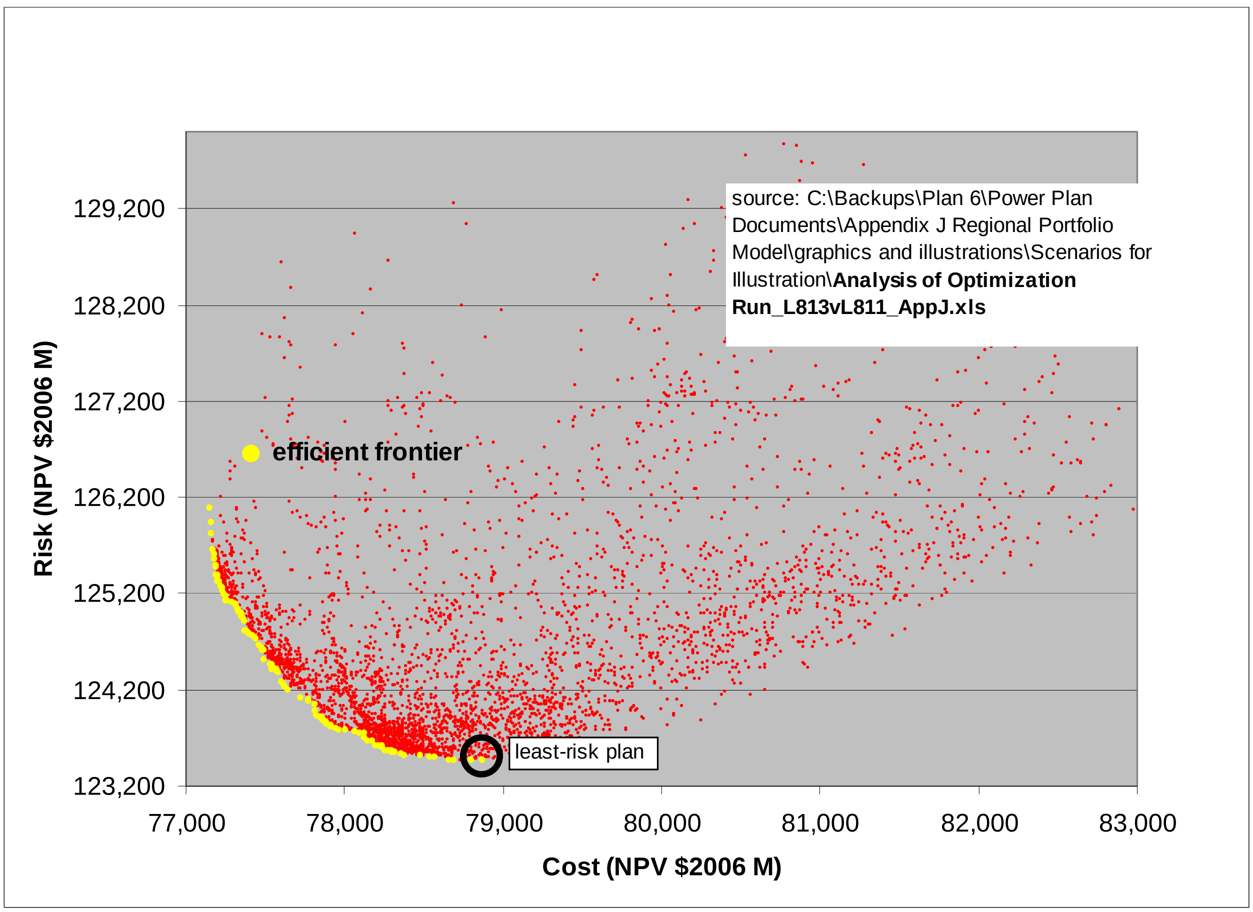


**Figure J-23: Carbon Risk Least-Risk Resource Portfolio**

| | |
|---|---|
| 50 | **Lost opportunity** conservation cost-effectiveness threshold over market ($2006/MWh) |
| 3092 | **Lost opportunity** conservation by end of study (MWa) |
| 80 | **Discretionary** conservation cost-effectiveness threshold over market ($2006/MWh) |
| 2867 | **Discretionary** conservation by end of study (MWa) assuming 160MWa/year limit |
| 5958 | **Total conservation (MWa)** |

**Cumulative MW**, by earliest date to begin construction

| | Dec-15 | Dec-17 | Dec-19 | Dec-21 | Dec-23 |
|---|---|---|---|---|---|
| **CCCT** | 0 | 0 | 3735 | 3735 | 3735 |
| **SCCT** | 170 | 170 | 680 | 680 | 680 |
| **RPS Resources** | 123 | 381 | 637 | 763 | 817 |

Source: "Schedules for plan resources 100302.xls", worksheet "Schedules (3)"

## Exposure to Wholesale Power Markets

To see how market reliance affects costs, consider the future illustrated in Figure J-24[16]. High gas price and electricity prices, combined with high carbon penalty, create a treacherous outcome for the least-risk portfolio. While the average cost for this plan across futures, including carbon penalty, is $78.9 billion NPV, this future costs $ 222.4 billion.

Because of the high load growth and hydrogeneration shortages in several years, the region is forced to purchase power under unfavorable circumstances. (See Figure J-25) This occurs despite the construction and operation of the additional resources in the model's least-risk portfolio. While the region's energy adequacy metric shows a surplus from today's perspective, this future highlights the possibility that the region can nevertheless become exposed. The cost and rate excursions in Figure J-26 correspond directly to periods of low hydrogeneration and to high energy import levels.

16 This future, number 150, and all of the other 749 futures – and their impacts on resource portfolios – may be viewed by down-loading "spinner graphs" from the Council's website. This example is from the Carbon Risk least-risk portfolio spinner graph, http://www.nwcouncil.org/dropbox/Spinner_091220_2157_L813_2990_LR.zip

**Figure J-24: Elements of Future 150**

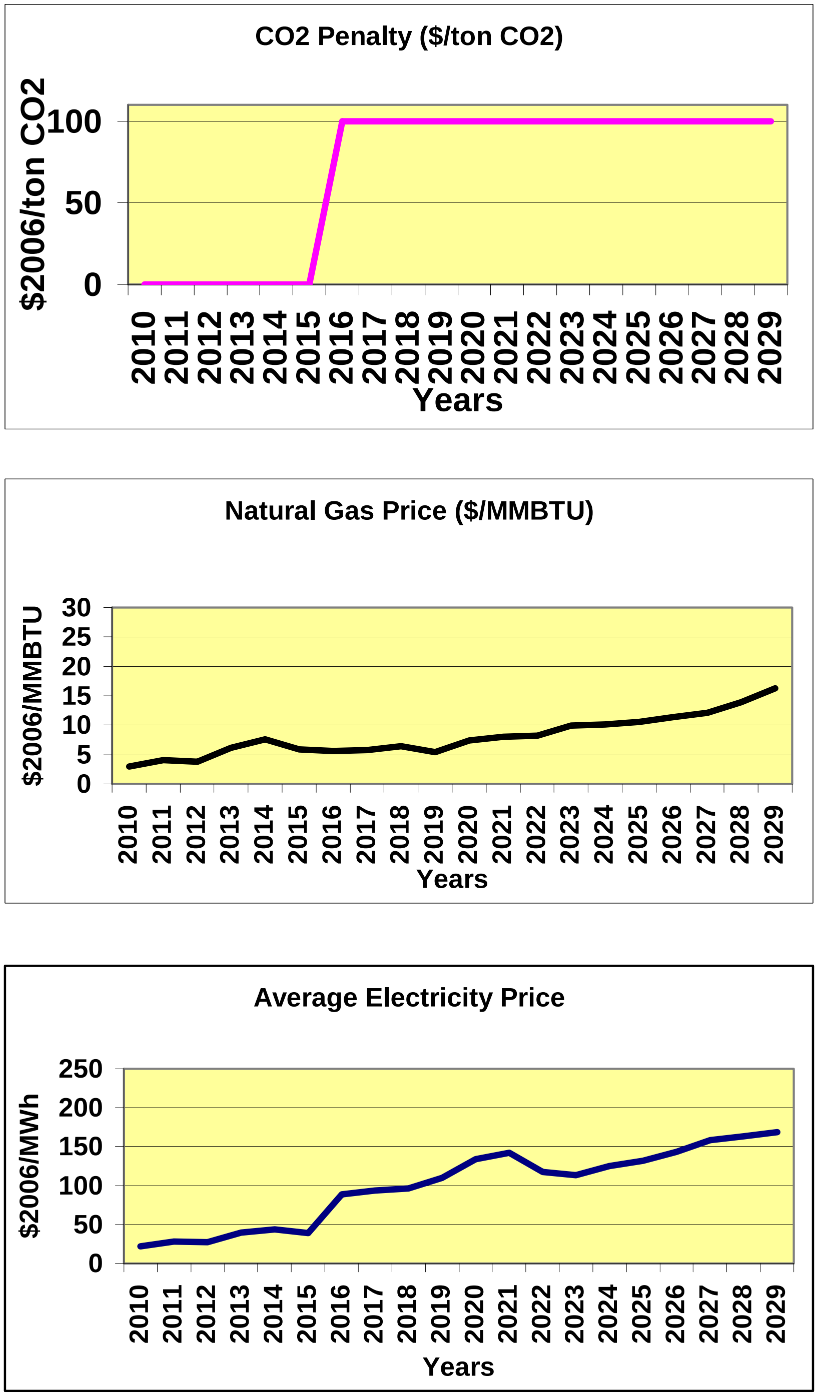



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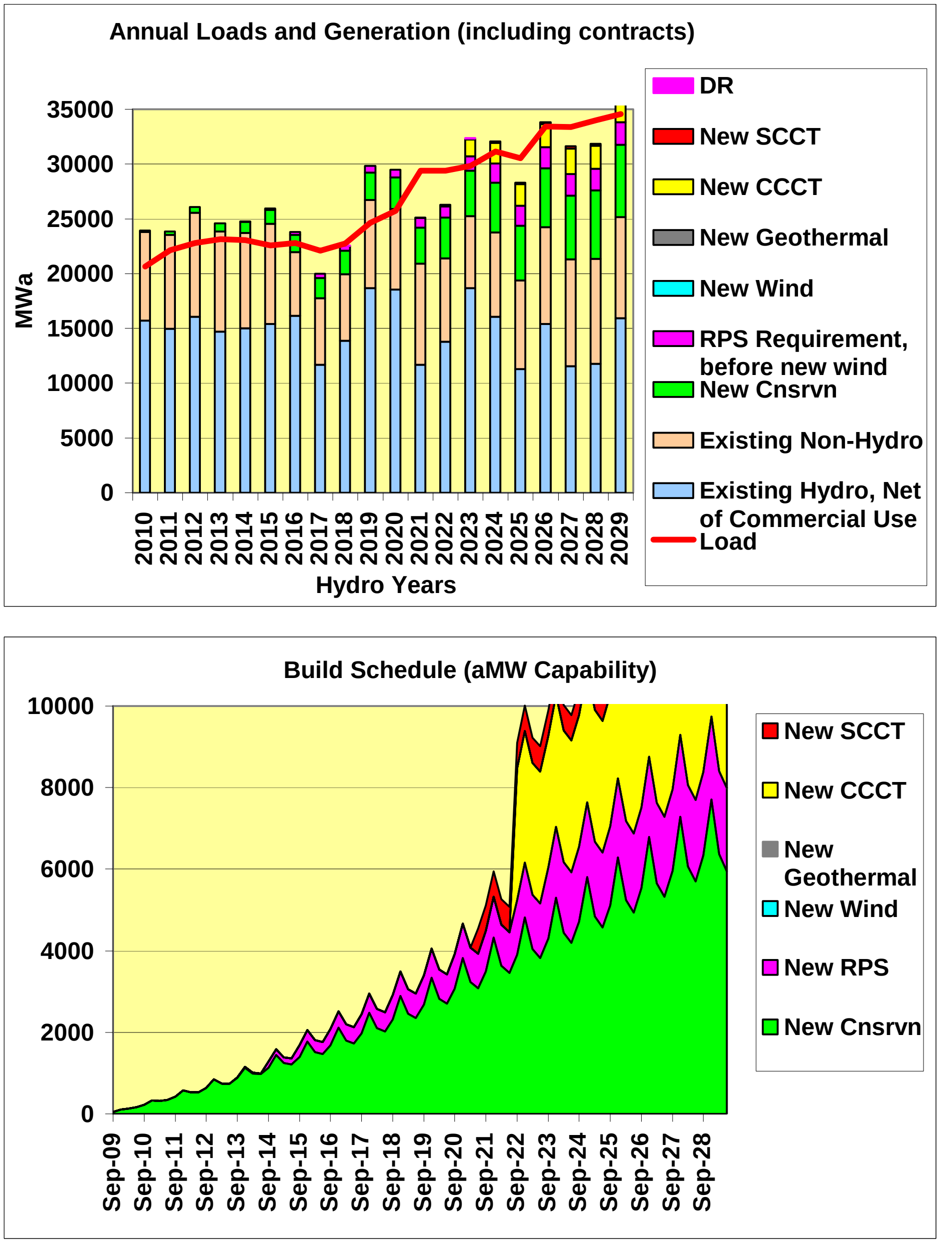
**Figure J-25:  Loads, Operation, and Build Out**

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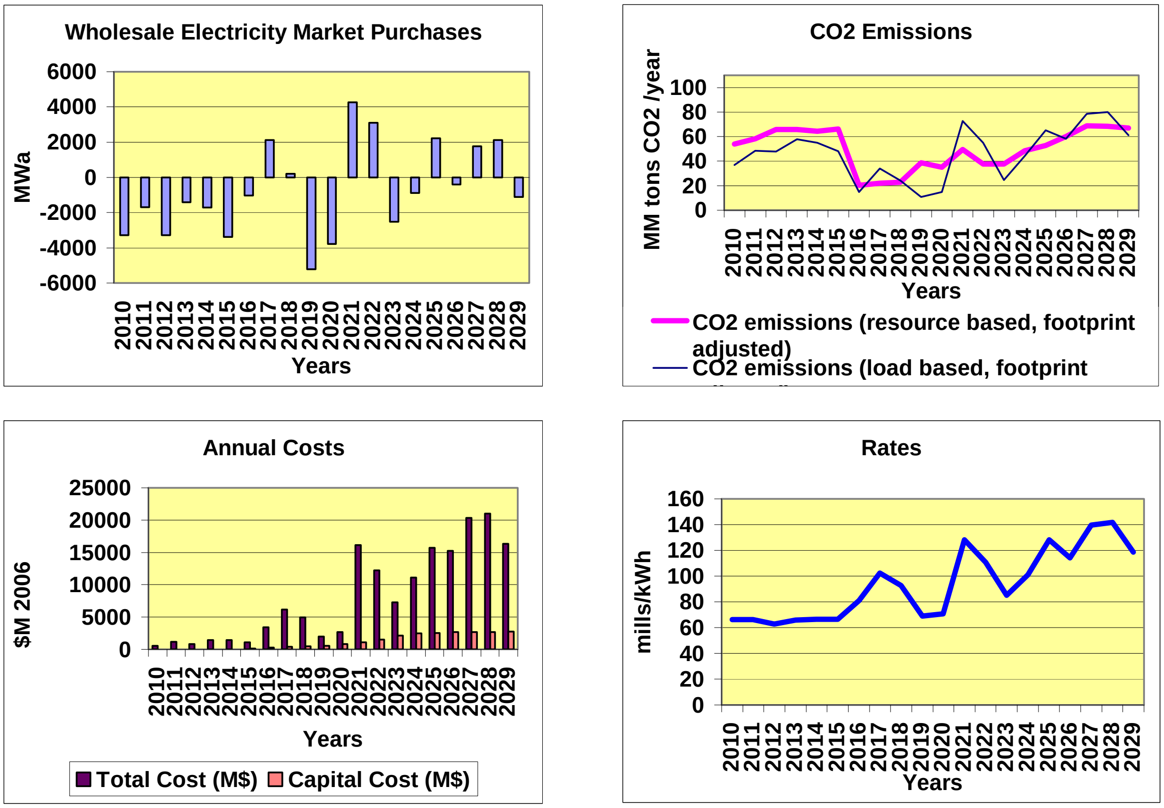
Finally, Figure J-26 shows that when electricity prices remain high and the region needs power, the coal plants in the region will run and emissions will remain high.  Without the regional coal plants, the maximum regional $CO_2$ emission levels would never exceed 35 million tons per year. Even with a \$100per ton carbon penalty, the $CO_2$ emission levels in the latter years of this scenario consistently run above today's levels.

**Figure J-26: Other Consequences**

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An obvious response to this risk might be to acquire enough resources to minimize the likelihood of exposure to the market. Depending on the selection of resources, however, this can present its own risks. Some resources will create greater cost, for example, if wholesale electricity prices crash.

In the second future, loads fall or remain flat, new resources are surplus to the region's needs, and low market prices occur. The performance of two plans under this future reveals the difference that resource choice can make. The first plan under the new future is the same plan as before, the least risk plan from the Carbon Risk scenario

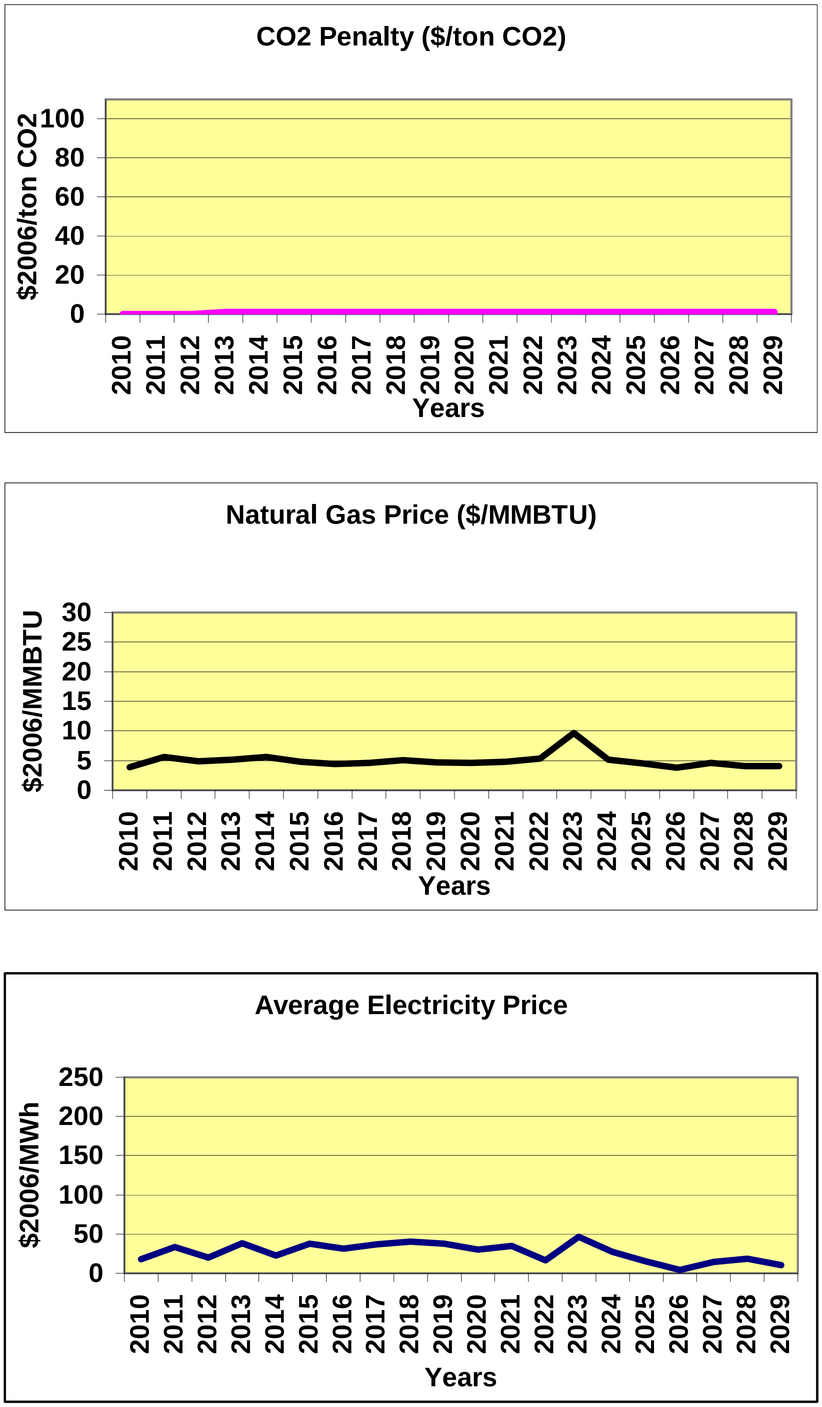
## Conservation Value in Surplus Power Markets

The least-risk plan supports higher levels of conservation and conventional resource development. The risk associated with high levels of capital investment in conservation and generation resources is that the region turns surplus and electricity prices fall.

Selecting from among the lower load-growth futures, there are many in which load remains flat and electricity prices either hold or fall. The most extreme by these appears to be future 185. The following scenario is from the same spinner workbook as before.

Figure J-27 presents a future where natural gas and electricity prices remain about where they are today until the last five years of the study, when they soften. More significantly, load growth, illustrated in Figure J-28, is relatively flat. This results in significant surplus of resources in the out years, largely due to better-than-normal hydrogeneration conditions.

**Figure J-27: Elements of Future 185**

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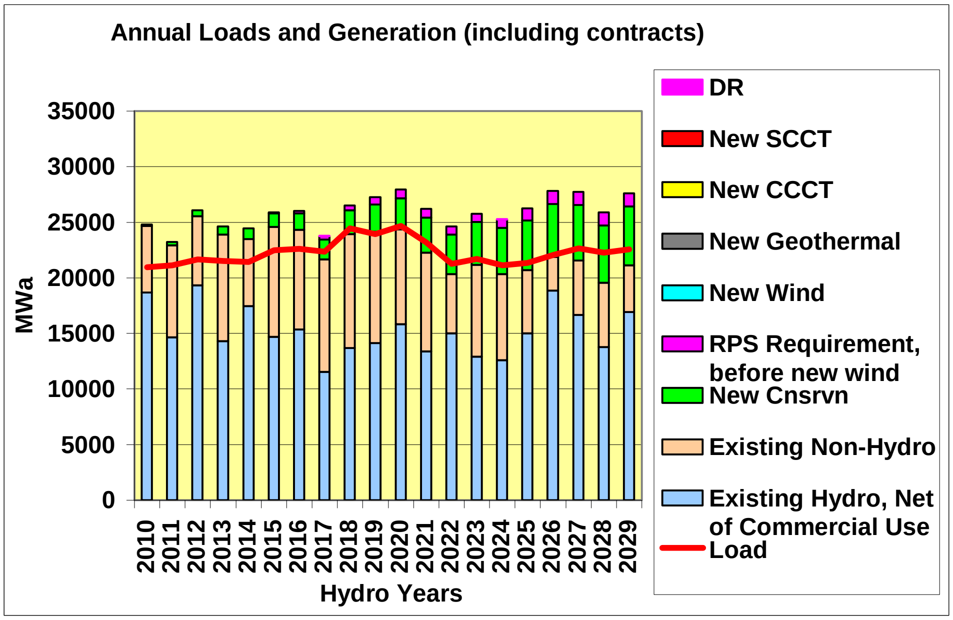
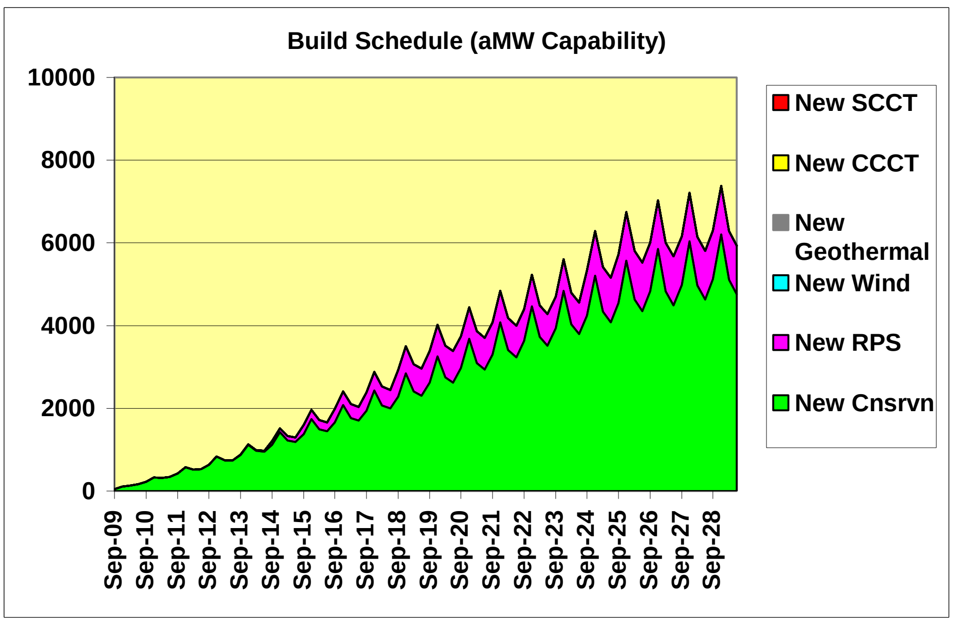
In response to generally lower electricity prices, the region does not construct the combustion turbines that have been sited and licensed in the portfolio. Lower electricity prices result in little generation beyond the must-run units. Must-run gas-fired generation is mostly customer cogeneration installations and units necessary to provide for system stability. On an energy basis, the RPS and conservation that the region has built is surplus to its requirements.

**Figure J-28: Loads, Operation, and Build Out of Future 185**

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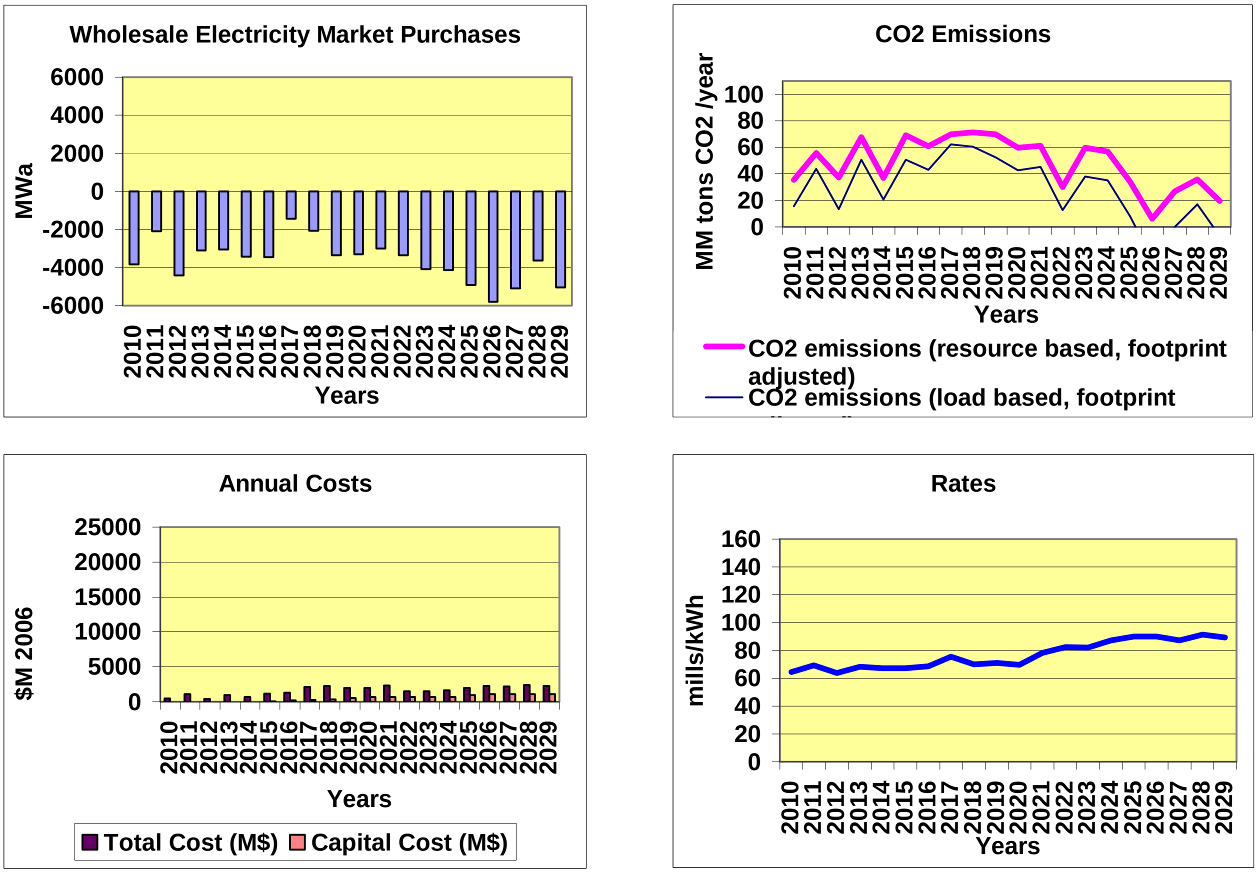
Despite this extreme set of circumstances, the total cost of the system is $40.3 billion. This figure is less than the expected cost for this plan across futures. Evident in Figure J-29 is reduced cost and rate variation and $CO_2$ emissions.

The advantage of conservation and, to a lesser extent renewables, is a low or zero operating cost. At any electricity price, these resources contribute some level of value. Figure J-29 shows that, while thermal generation is shut down, the region is still exporting surplus energy and reducing annual costs.  Revenue requirements are only about 2 mills per kWh higher than average.

Lower costs are to be expected, however, in a future with low loads and low market prices.  The question is, could the region have done better by building conventional thermal resources?  The third example sheds light on the answer.

**Figure J-29:  Consequences of Future 185**




source:...\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Scenarios for llustration\Spinner 091220_2157_L81 2990_LR_for_AppJ.xls

## A Plan without Conservation

The Council performed a study with the same assumptions as the first plan presented above, except that no conservation was available to the model.  As before, the study included RPS resources and the $0-100 per ton stochastic carbon penalty.  The schedule for the earliest construction of each resource in this plan appears in Figure J-30.  Without conservation, RPS requirements are slightly higher.

As mentioned above, this is the same future as the one in the preceding example, number 185.  Figure J-27 summarized several of the key aspects of this future.[17]

17 The spinner graph that this scenario is from can also be downloaded: http://www.nwcouncil.org/dropbox/Spinner_091223_1348_L813a.zip

**Figure J-30: No-Conservation Least-Risk Resource Portfolio**

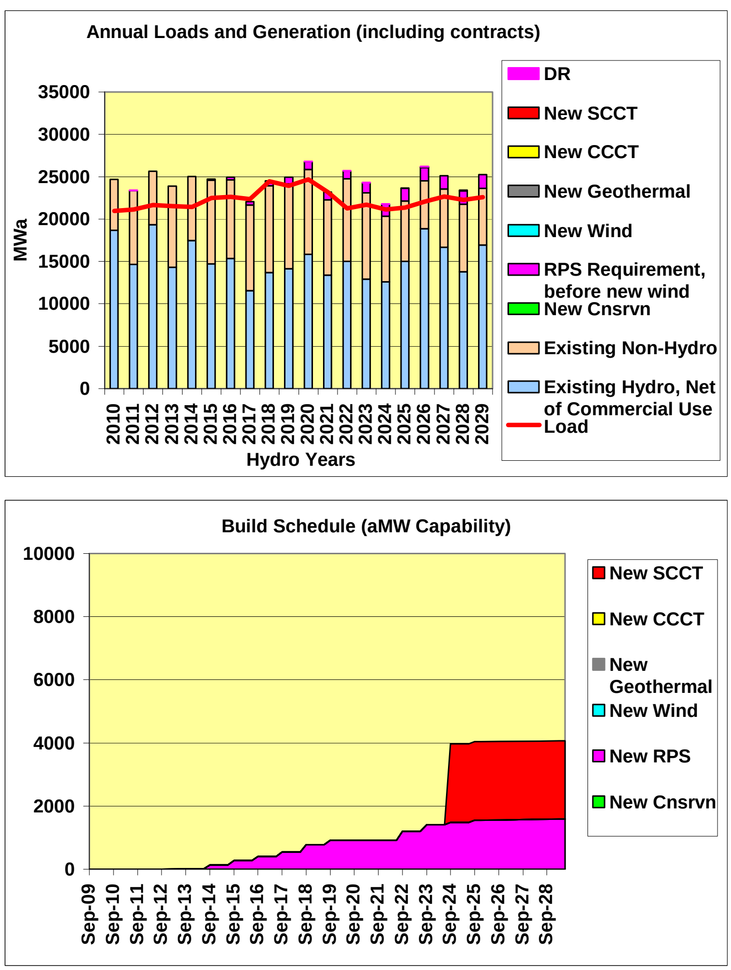
**Cumulative MW**, by earliest date to begin construction

| | Dec-09 | Dec-13 | Dec-15 | Dec-17 | Dec-19 | Dec-21 | Dec-23 |
|---|---|---|---|---|---|---|---|
| **CCCT** | 0 | **4150** | **4565** | **4565** | **12035** | **12035** | **12035** |
| **SCCT** | **170** | **170** | **170** | **340** | **340** | **3060** | **3060** |
| **RPS Resources** | 0 | **1** | **156** | **450** | **758** | **927** | **1502** |

Source: "Schedules for plan resources 100302.xls", worksheet "Schedules (4)"

The model's plan has responded to circumstances about as well as could be desired. Loads and electricity prices have signaled utilities not to build the combined-cycle combustion turbines. (By design, the decisions in the model are not always so fortunate. The decisions imitate forecasts without perfect foresight.) This leaves only the single-cycle units for reliability and unforeseen events. These single-cycle units run very few hours. The capacity factors never reach five percent, averaging closer to two percent. Figure J-31 presents salient features of system operation.

**Figure J-31: Loads, Operation, and Build Out of Future 185 for the No Conservation Plan**

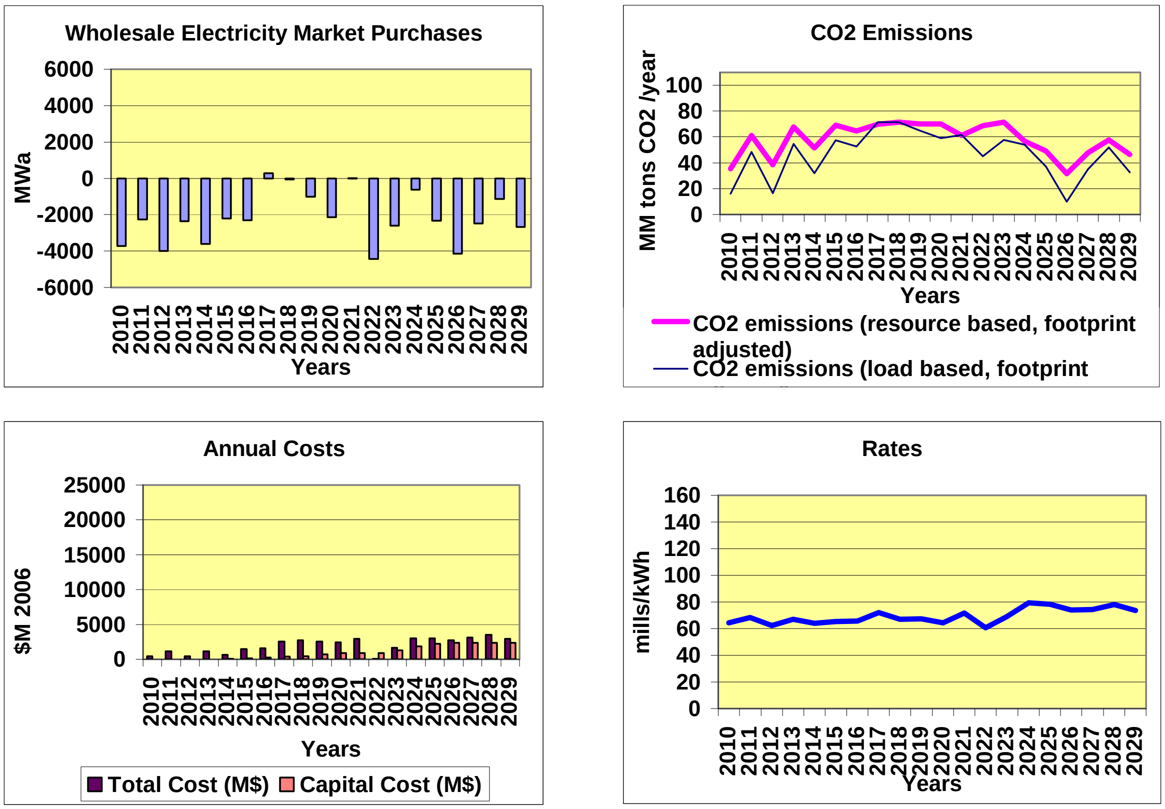



source:...\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Scenarios for Illustration\Spinner_091223_1348_L813a_for_AppJ.xls

Many of the consequences of future 185 to this plan appear in Figure J-32. Two things to notice are the rates (revenue requirements) and the emissions. The rates are lower with this plan by 15.6 mills per kWh, about 17 percent. Of course, customers pay bills, not rates, and the bills will be roughly 23 percent *higher* with this plan. We know this because the net present value costs for the no conservation plan are $9.3 billion higher under this future.

Carbon emissions are much higher with the "no conservation" plan. Fortunately for this scenario, there is no carbon penalty or the contrast in cost with the first plan would be even starker.

**Figure J-32: Consequences of Future 185 for the No Conservation Plan**




source:...\Plan 6\Power Plan Documents\Appendix J Regional Portfolio Model\graphics and illustrations\Scenarios for Ilustration\Spinner_091223_1348_L813a_for_AppJ.xls

Collectively, these three scenarios demonstrate why there is a market adder for conservation. It is better to have slightly too many resources than too few. Most utility planners understand the value of keeping some capacity in reserve for unforeseeable circumstances. Examining the candidates for such a reserve, conservation is expected to be the best choice. These examples suggest that conclusion; Council studies support it. If the region develops only conservation that is less expensive than wholesale power, however, where would such a reserve come from? Wouldn't utilities want to meet ***expected*** energy requirements with this inexpensive resource? Going up the conservation supply curve ***above*** wholesale market prices – using an adder – provides the additional energy.

This additional conservation energy is more expensive on a real levelized basis than wholesale power. Traditionally, low capital cost-high operating cost resources like combustion turbines serve the role of providing reserves. It seems at first counterintuitive that conservation would be a good choice for reserves.

Conservation is the least expensive candidate for reserve energy and capacity precisely because it performs better in futures where electricity prices *are lower*. Such futures, in turn, are more likely if the region takes a low-risk approach to selecting its resource portfolio. A low-*risk* portfolio will have more resources than a low-*cost* portfolio, and additional resources will tend to produce lower and more stable power market prices. Conservation performs better in these situations because it has value even at low power prices, whereas dispatchable resources provide no value. In high price scenarios, of course, conservation performs no worse than dispatchable generation.

This is not to say that the region can add conservation without limit and not increase risk. Quite the contrary is true. At some point, additional conservation will *increase* economic risk. The role of the model is to help the Council find the prudent level of and best policy for acquiring this resource.

The Fifth Power Plan also presented many examples of how a least-risk plan reduces rate and cost volatility and market exposure. Council studies have confirmed that the same kinds of behavior take place with Sixth Power Plan's resource portfolios.

# GENERATION RESOURCES IN THE MODEL

This section identifies generation resources assumed operating currently in the region. Existing resources in the RPM are aggregated by heat rate, fuel type, fuel source, technology, and variable operations and maintenance (VOM) rates. The following table lists each unit's capability in average megawatts and the aggregate unit with which it is associated. The capability includes discounting for planned and unplanned (forced) outages.

While it is not indicated here, a portion of certain plants may belong to independent power producers (IPPs). Those portions appear explicitly Chapter 9.

**Table J-4: Existing Resources**

| Unit (New Name) | Aggr_Unit | Capability (MWa) after POR and FOR |
|---|---|---|
| **18th Street (Springfield ICs, Springfield Gen Farm)** | West 3 | 8.7 |
| **Barber Dam** | Must Run | 1.0 |
| **Basin Creek group** | East 4 | 16.3 |
| **Beaver 1 - 7** | West 3 | 417.0 |
| **Beaver 8** | East 7 | 20.7 |
| **Bennett Mountain** | West 4 | 151.4 |
| **Bettencourt Dry Creek Dairy** | Must Run | 2.1 |
| **Big Hanaford CC1A-1E** | West 1 | 208.1 |
| **Biglow Canyon I** | Must Run | 37.7 |
| **Biomass One 1 & 2** | Must Run | 21.0 |
| **Boardman** | Boardman | 401.5 |
| **Boulder Park 1-6** | East 4 | 22.0 |
| **Box Canyon** | Must Run | 0.3 |
| **Box Canyon 1 & 2** | Must Run | 1.6 |
| **Broadwater** | Must Run | 1.0 |
| **Bull Run No. 1 (Portland Hydro)** | Must Run | 10.7 |
| **Bull Run No. 2 (Portland Hydro)** | Must Run | 6.2 |

| | | |
|---|---|---|
| **Bypass** | Must Run | 1.5 |
| **Central Oregon Siphon** | Must Run | 2.8 |
| **Centralia 1** | Centralia | 613.1 |
| **Centralia 2** | Centralia | 613.1 |
| **Chehalis Generating Facility** | West 1 | 436.3 |
| **City of Albany (Vine Street WTP)** | Must Run | 0.2 |
| **Clearwater Hatchery (Dworshak)** | Must Run | 0.5 |
| **Coffin Butte 1 - 5** | Must Run | 4.8 |
| **Cogen II (D.R. Johnson) 1 & 2** | Must Run | 6.7 |
| **Colstrip 1** | Colstrip 1&2 | 140.5 |
| **Colstrip 2** | Colstrip 1&2 | 140.5 |
| **Colstrip 3** | Colstrip 3&4 | 474.0 |
| **Colstrip 4** | Colstrip 3&4 | 623.0 |
| **Columbia Generating Station** | Must Run | 996.1 |
| **Combine Hills I** | Must Run | 12.3 |
| **Condon** | Must Run | 15.0 |
| **COPCO 1 (1 & 2)** | Must Run | 12.6 |
| **COPCO 2 (1 & 2)** | Must Run | 16.8 |
| **Covanta Marion** | Must Run | 8.4 |
| **Cowiche Hydroelectric Project** | Must Run | 1.0 |
| **Coyote Springs 1** | East 1 | 204.1 |
| **Coyote Springs 2** | East 1 | 218.2 |
| **Danskin (Evander Andrews) CT1** | West 4 | 144.6 |
| **Danskin group** | East 7 | 78.2 |
| **Danskin group** | East 7 | 78.2 |
| **Dietrich Drop** | Must Run | 1.0 |
| **Don Plant (Simplot Pocatello)** | Must Run | 5.9 |
| **Dry Creek** | Must Run | 1.8 |
| **Dry Creek Landfill** | Must Run | 2.9 |
| **Elkhorn Valley** | Must Run | 30.0 |
| **Encogen 1-4** | Must Run | 134.3 |
| **Everett Cogeneration Project** | Must Run | 21.9 |
| **Evergreen Forest Products (Tamarack)** | Must Run | 4.2 |
| **Fall Creek 1 - 3** | Must Run | 1.0 |
| **Fall River** | Must Run | 3.1 |
| **Falls Creek** | Must Run | 2.1 |
| **Farmers Irr. Dist. No. 2 (Copper Dam)** | Must Run | 1.0 |
| **Farmers Irr. Dist. No. 3 (Peters Drive)** | Must Run | 0.9 |
| **Foote Creek I** | Must Run | 14.9 |
| **Foote Creek II** | Must Run | 0.6 |
| **Foote Creek IV** | Must Run | 6.1 |
| **Fossil Gulch** | Must Run | 2.9 |
| **Frederickson 1** | West 4 | 76.9 |
| **Frederickson 2** | West 4 | 76.9 |
| **Frederickson Power 1** | West 1 | 225.7 |
| **Fredonia 1** | West 4 | 107.1 |
| **Fredonia 2** | West 4 | 107.1 |
| **Fredonia 3** | West 3 | 52.7 |
| **Fredonia 4** | West 3 | 51.8 |
| **Freres Lumber** | Must Run | 8.4 |
| **Georgia-Pacific (Camas)** | Must Run | 43.7 |
| **Georgia-Pacific (Wauna)** | Must Run | 22.7 |

| | | |
|---|---|---|
| **Glenns Ferry Cogeneration** | Must Run | 8.3 |
| **Goldendale CC 1A & 1B** | East 1 | 204.9 |
| **Goodnoe Hills** | Must Run | 28.2 |
| **Grays Harbor Energy Facility (Satsop)** | West 1 | 545.4 |
| **H.W. Hill (Roosevelt Biogas) 1 - 5** | Must Run | 9.6 |
| **Hampton Lumber** | Must Run | 6.1 |
| **Hay Canyon** | Must Run | 30.3 |
| **Hazelton A** | Must Run | 1.0 |
| **Hazelton B** | Must Run | 1.5 |
| **Hermiston Generating Project CC1A & 1B** | East 2 | 195.0 |
| **Hermiston Generating Project CC2A & 2B** | East 2 | 195.0 |
| **Hermiston Power Project** | East 3 | 438.0 |
| **Hidden Hollow** | Must Run | 1.5 |
| **Hopkins Ridge** | Must Run | 47.0 |
| **Hoquiam Diesels** | Ignore | 9.2 |
| **Horseshoe Bend** | Must Run | 3.6 |
| **Horseshoe Bend Hydroelectric** | Must Run | 3.1 |
| **Ingram Warm Springs Ranch B** | Must Run | 0.6 |
| **Iron Gate** | Must Run | 9.4 |
| **Jim Bridger 1** | Bridger | 447.1 |
| **Jim Bridger 2** | Bridger | 447.1 |
| **Jim Bridger 3** | Bridger | 447.1 |
| **Jim Bridger 4** | Bridger | 447.1 |
| **John H. Koyle (Koyle Ranch Hydroelectric) 1-3** | Must Run | 0.5 |
| **Judith Gap** | Must Run | 16.1 |
| **Kettle Falls Generating Station** | Must Run | 44.6 |
| **Kettle Falls GT** | Must Run | 6.0 |
| **Klamath Cogeneration Project** | East 1 | 396.6 |
| **Klamath Generation Peakers 1 & 2** | East 5 | 42.5 |
| **Klamath Generation Peakers 3 & 4** | East 5 | 42.5 |
| **Klondike I** | Must Run | 7.2 |
| **Klondike II** | Must Run | 22.5 |
| **Klondike III** | Must Run | 37.6 |
| **Koma Kulshan** | Must Run | 3.6 |
| **Lancaster (Rathdrum CC)** | East 1 | 232.2 |
| **Lateral No. 10** | Must Run | 0.5 |
| **Leaning Juniper** | Must Run | 30.2 |
| **Little Wood River Ranch** | Must Run | 0.5 |
| **Lower Low Line No. 2** | Must Run | 1.4 |
| **LQ-LS Drains** | Must Run | 0.9 |
| **Magic Dam** | Must Run | 1.6 |
| **March Point 1 - 4** | Must Run | 117.5 |
| **Marengo I** | Must Run | 42.2 |
| **Marengo II** | Must Run | 21.1 |
| **Meyers Falls** | Must Run | 0.5 |
| **Middle Fork Irrigation District 1** | Must Run | 0.3 |
| **Middle Fork Irrigation District 2** | Must Run | 0.3 |
| **Middle Fork Irrigation District 3** | Must Run | 1.0 |
| **Mile 28 (1 & 2)** | Must Run | 0.5 |
| **Mink Creek** | Must Run | 0.5 |
| **Mint Farm** | West 1 | 267.7 |
| **Mirror Lake (Hutchinson Creek)** | Must Run | 0.5 |

| | | |
|---|---|---|
| **Montana One (Colstrip Energy)** | Colstrip 1&2 | 11.8 |
| **Mora Canal Drop** | Must Run | 0.9 |
| **Morrow Power** | East 6 | 21.3 |
| **N-32 (Northside Canal)** | Must Run | 0.3 |
| **Nine Canyon** | Must Run | 28.8 |
| **North Valmy 1** | Valmy | 116.2 |
| **North Valmy 2** | Valmy | 122.6 |
| **Northeast 1** | East 8 | 5.4 |
| **Northeast 2** | East 8 | 5.4 |
| **Olympic View 1 & 2** | West 3 | 4.9 |
| **Opal Springs** | Must Run | 1.6 |
| **Owyhee Dam** | Must Run | 0.5 |
| **Owyhee Tunnel No. 1** | Must Run | 3.5 |
| **Plummer Forest Products** | Must Run | 5.3 |
| **Port Westward CC1A & 1B** | West 1 | 357.5 |
| **Portneuf River** | Must Run | 0.5 |
| **Potlatch (Lewiston) 1 - 4** | Must Run | 63.1 |
| **Raft River I** | Must Run | 12.2 |
| **Rathdrum 1** | West 4 | 74.8 |
| **Rathdrum 2** | West 4 | 74.8 |
| **River Road Generating Plant** | West 1 | 208.1 |
| **Rock Creek #1** | Must Run | 0.5 |
| **Rock Creek #2** | Must Run | 0.5 |
| **Rock River I** | Must Run | 18.0 |
| **Ross Creek** | Must Run | 0.1 |
| **Rough & Ready Lumber** | Must Run | 1.0 |
| **Rupert Cogeneration** | Must Run | 8.3 |
| **Savage Rapids Diversion** | Must Run | 0.6 |
| **Short Mountain group** | Must Run | 2.3 |
| **Shoshone/Shoshone II** | Must Run | 0.5 |
| **Sierra Pacific (Aberdeen)** | Must Run | 8.5 |
| **Sierra Pacific (Fredonia)** | Must Run | 2.6 |
| **Skookumchuck** | Must Run | 1.8 |
| **Slate Creek** | Must Run | 2.2 |
| **South Dry Creek** | Must Run | 0.3 |
| **St. Anthony** | Must Run | 0.3 |
| **Stateline** | Must Run | 90.1 |
| **Sumas Cogeneration Station** | Must Run | 103.2 |
| **Tenaska Washington Partners Cogeneration Station** | West 2 | 205.6 |
| **Tiber-Montana** | Must Run | 0.9 |
| **Tieton** | Must Run | 7.1 |
| **Tuttle Ranch (Ravenscroft)** | Must Run | 0.6 |
| **Twin Falls (TFHA)** | Must Run | 3.1 |
| **Twin Reservoirs** | Must Run | 0.5 |
| **Upriver** | Must Run | 4.3 |
| **Vaagen Brothers Lumber** | Must Run | 2.5 |
| **Vansycle Wind Energy Project** | Must Run | 7.5 |
| **Wapato Drop 2 (#1)** | Must Run | 1.5 |
| **Wapato Drop 3 (#1 - 2)** | Must Run | 1.0 |
| **Weyerhaeuser (Springfield) 4 (WEYCO)** | Must Run | 21.0 |
| **Wheat Field** | Must Run | 29.0 |
| **Wheelabrator Spokane** | Must Run | 19.3 |

| | | |
|---|---|---|
| **White Creek** | Must Run | 60.5 |
| **Whitehorn Generating Station 2** | West 4 | 76.9 |
| **Whitehorn Generating Station 3** | West 4 | 76.9 |
| **Wild Horse Wind** | Must Run | 68.6 |
| **Wilson Lake** | Must Run | 1.5 |
| **Wolverine Creek** | Must Run | 18.1 |
| **Yellowstone Energy (BGI)** | Must Run | 15.8 |

source: ...\Plan 6\Studies\Data Development\Resources\Existing Non-Hydro\091018 Database system**Explorer_100228_225825.xls**, worksheet "Unit Comparisons"

Many of the units, it may be noted, are in the "must run" category. The reasons for this assignment depend on the particular plant. Some units are combined heat and power (CHP) installations owned by customers. Wind, geothermal, and most other renewables belong to his family because they have virtually zero variable operating cost. Run of River Hydro, which is generally not dispatchable, and the Columbia Station nuclear power plant, which has very low operating cost, also belong to this category.

# THE UNFORESEEABLE

Technological innovation can rewrite the economic rules of generating power. Legislative and regulatory initiatives can have and have had this effect. How does the Council's RPM model deal with such "game changers?"

While the events are impossible to forecast, their effects on power system cost are foreseeable. Studies can thereby discover situations that deserve attention.

For example, consider the possibility of a breakthrough that makes solar photovoltaic generation cost effective for individual homeowners. If a large number of homeowners installed these systems, it is reasonable to expect load requirements would decline. The utilities themselves would likely find a way to harness the technology in larger quantities and at even lower cost. Surplus utility generation would drive down wholesale power prices. Could it impact natural gas prices? Possibly. It is difficult to imagine, on the other hand, how this breakthrough would affect hydrogenation or power plant forced outages.

In this manner, a solar photovoltaic breakthrough is interpreted in terms of the sources of uncertainty the Council's model already addresses. Then how do these unforeseeable events change the standard representation of the uncertainties?

Innovations with unknown likelihood change the scale of and relationship among uncertainties. Council studies reflect a larger scale of uncertainty than intuition might first suggest. This simply reflects the potential for a larger pool of contributing factors than history provides. Using alternative correlations among uncertainties allows for the possibility that market structures will change, regulations will evolve, and technology will transform.

Combining futures in unlikely ways, moreover, reveals how alternative sources of uncertainty can conspire to bring extraordinary risk. The coincidence of several "unlikely" forces has been responsible for catastrophic events in very recent history, such as the subprime mortgage debacle.

Once revealed, however, it is still incumbent on the Council to decide whether a particular combination of events is meaningful. Modeling is a powerful tool for ferreting out sources of risk. Judgment and experience, however, are the ultimate measures of risk and of any plan's merit in meeting risk.

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## INTRODUCTION

Smart grid technology has the potential to bring revolutionary changes to the structure and operation of the power system. The technology could make make it possible for customers to participate in solving power system problems to an unprecedented degree. It could cut costs and improve reliability by giving system operators a level of understanding of the minute-by-minute state of the system, and an ability to make quick and effective adjustments in operation, that they have never had before. The changes could affect the power system from generation to transmission to distribution to consumption, and the potential range of change is often compared to that of the Internet.

## COMPONENTS OF THE SMART GRID

As a working definition for this discussion, the smart grid is a combination of improved technologies that can be used to improve the operation of the power system: These technologies can be grouped into three general categories: metering, communication, and intelligence and control.

## *Metering*

The metering category includes a wide variety of devices such as: improved versions of utility meters that measure customers' use every few minutes or seconds; sensors in electrical equipment in consumers' houses or businesses; devices that sense load at many points in the transmission and distribution system; and sensors that read the chemical composition of cooling oil in substation transformers, warning of impending equipment failure. The increase in information on the state of the power system could be orders of magnitude, opening many possibilities for increasing the efficiency and reliability of the power system.

## *Communication*

The enhanced data from improved metering must be communicated in order to be useful. That communication can be from the meter to the utility, from one part of the utility to another, or from the utility to customers. Communication technology continues to improve, both in capability and cost. The paths for communication across the power system range from copper wire and fiber optics to a variety of powerline carrier and wireless technologies. The preferred options are likely to vary depending on the particular application, and the relative advantages of the alternatives are still in flux.

Advanced utility meters could play a central role in communication, not only of customers' total use by time interval, but also in passing data from individual appliances and equipment inside the customers' houses and businesses. Such data can also move by such non-utility paths as the Internet.

## *Intelligence and Control*

Improved collection and communication of data on the state of the power system does not guarantee improved operation of the system. The data must also be translated into information that guides decisions, and those decisions must be executed. This processing and execution may be simple and close to the data source, such as a single device in a clothes dryer that senses power system frequency and shuts down the dryer's heater when the frequency drops below a set level. Or it may be more complex; it could incorporate a real time price signal from the power system, current refrigeration equipment requirements, and adaptive control of multiple pieces of equipment to reduce demand for electricity in a grocery store. Or the processing may condense large amounts of hourly load data to summary differences in energy use that can be used to guide efficiency program strategy.

# BENEFITS FROM THE SMART GRID

Predicting the long-term effect of these technologies is like predicting the effect of the Internet in 1990, before the introduction of web browsers such as Netscape Navigator.[1] However, significant benefits will likely come in three general areas: demand response, operational efficiency, and capital savings.

## *Demand Response*

Demand response is the temporary, voluntary change in electricity use when the power system is stressed. Demand response was first covered in the Fifth Power Plan and is treated in more detail in Chapter 5 and Appendix H of this plan. The general effect of smart grid technologies on demand response is to reduce its cost, increase its flexibility, and improve the verification of demand response. These technologies extend possibilities for demand response in a variety of ways:

1. The smart grid could send signals directly to customers' equipment, not only cycling air conditioners (as is done now) but also controlling such equipment as clothes dryers, water heaters, dishwashers and pool pumps. The extent of modification in each customer's pattern of electricity use could depend on the amount of stress the system faces and that customer's willingness to participate for compensation. The customer could also preprogram the response so that the equipment would respond automatically, unless he or she overrides the programmed response.

2. Devices that use an under-frequency signal to interrupt some appliance functions like clothes dryer heating, automatic defrosting of refrigerators, and water heating are very cheap when installed when the appliances are manufactured. This is a new kind of demand response, an almost instantaneous "last ditch" measure when other measures turn out to be inadequate and the alternative is rolling blackouts.

3. Sensor and communication equipment have helped create an industry of demand aggregators. These aggregators can pool and dispatch consumers' equipment to provide load reductions with response times, reliability, and numbers of megawatts that rival conventional generators.

4. Until now, demand response has mostly been seen as a means of providing peaking capacity and contingency reserves. However, if smart grid technology continues to develop, it could provide ancillary services such as regulation and load following. This possibility is described in more detail later in this appendix and in Appendix H on demand response.

[1] The Pacific Northwest National Laboratory conducted a 2003 study of the potential benefits of GridWise technologies, which generally correspond to the smart grid definition used in this appendix. That study arrived at a range of estimates from $46 billion to $117 billion net present value over 20 years (http://www.pnl.gov/main/publications/external/technical_reports/PNNL-14396.pdf). The Rand Corporation conducted an independent study of the same topic in 2004, and arrived at an even wider range of benefits, $32 billion to $132 billion net present value over 20 years. http://www.rand.org/pubs/technical_reports/2005/RAND_TR160.pdf). A study done now would probably not be able to narrow the range of benefits greatly.

### *Operational Efficiencies*

The smart grid could also enable operational efficiencies in the power system. Advanced metering should reduce the cost of meter reading, of course, but meters with two-way communication should also reduce the cost and delay of locating outages. With appropriate control capability, connecting new customers and disconnecting old ones should be cheaper and quicker.

The smart grid could also make possible significant reductions in energy use. Traditionally, distribution feeders are operated well above 114 volts. This practice wastes energy, but maintains a voltage margin that protects appliances from damage that can occur if voltage drops below 114. Some smart grid technologies allow more precise control of voltage on distribution circuits, allowing voltage to be maintained closer to 114 without risking excursions below 114, reducing line losses and appliance energy use. This practice is documented in Chapter 4 and Appendix E as "conservation voltage reduction."

### *Energy Efficiency*

In addition to the efficiencies in the operation of the power delivery system, the smart grid offers possible contributions to energy efficiency at the customer level. The smart grid can give customers more information about their electricity use, which could change how much energy they use or when they use it. It could also influence what appliances they buy.

Improving the quality of information available to efficiency program designers and managers is another potential benefit. Evaluating the effectiveness of efficiency programs has always been crucial, but difficult. The smart grid could make measured results at the customer level available in near real time. This offers great promise for understanding what works and for making improvements in programs quickly.

### *Capital Savings*

The smart grid seems certain to allow existing resources to be used more intensively, reducing future investment requirements. For example, a substation transformer might serve one area with high loads during the day and then switch to serve a nearby area with high loads in the evening ("dynamic management of substation service"), avoiding the cost of a second transformer. Remote sensing and monitoring of line temperatures could also prevent excessive line sag, arcing to ground and the costs of outages and replacing transmission equipment.

## NECESSARY DEVELOPMENTS

For smart grid technologies to realize their full potential, the following developments are needed:

### *Interoperability*

Presently, many potential buyers of smart grid equipment have concerns about purchasing equipment that quickly becomes obsolete, concerns that discourage them from making the investment. To some extent, rapid technological advances make this unavoidable. But the risk can be reduced if, for example, meters purchased last year from manufacturer A and meters purchased this year from manufacturer B can both pass data over the same communication system. In that case, while last year's meters might not be this year's choice, they are still useful.

This is one example of the benefits of "interoperability," the ability to use equipment of different designs and manufacturers together. Interoperability is recognized as a difficult and important issue. The Gridwise Architecture Council was formed several years ago to take up this problem and continues to work on it.

### *Simplified Participation by Consumers*

While the smart grid will make a great deal more information available to utility operators and consumers, consumers have limited attention to give to understanding energy issues and making decisions on energy use. Consumers' participation in demand response programs, for example, will need to be as simple as possible for them. Most consumers will not take time every day to monitor prices that change frequently, but they may be willing to spend time once to choose from a menu of automated responses to future prices. Utilities or aggregators for utilities that make participation easy for consumers will be able to tap those consumers' potential contributions to the economical development and operation of the power system.

### *Utility Operators' Experience with the Smart Grid and Consumers*

Some smart grid technologies such as conservation and voltage reduction can be adopted by the utilities themselves so their evaluation by utilities should be relatively straightforward. However, many smart grid technologies like air conditioning cycling or critical peak pricing require consumer participation, which introduces an extra element of uncertainty to their evaluation. Until utilities and regulators have some experience with such technologies, they are unlikely to be widely adopted. Pilot programs and the experience gained from early adopters will help to encourage utilities to plan on these technologies as resource alternatives for the future.

All experience with smart grid technologies should of course be analyzed with the objective of understanding their current and future cost effectiveness.

## THE SMART GRID OF THE FUTURE

Imagining what a smart grid would look like conveys a sense of the scale of change that is possible.

### *Meeting Peak Load*

Spiking demand due to a summer heat wave could be mitigated by short interruptions in air conditioning, rotating among customers in a coordinated pattern so individual customers experience little or no change in their comfort. Other end uses such as refrigerator defrosting, clothes dryers, and swimming pool pumps could be included in a coordinated control strategy.

## *Notification and Location of Outages*

The smart grid could notify utilities of system outages immediately, rather than receiving phone calls from customers (perhaps hours after the outage occurs). Smart meters could let the utility know very precisely where the problem is without requiring a repair crew to search it out.

## *Integration of Plug-in Hybrids*

Plug-in hybrid electric vehicles (PHEV) could be combined and controlled to function as a storage battery for the power system. Many parties have suggested this possibility in which the combined PHEV batteries act as a large storage battery for the power system when they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low, for instance at night, and gives electricity back to the system when the cost is high during hot afternoons or cold snaps.[2] The smart grid could coordinate[3] this exchange.

## *Water Heaters for Peak Load, Load Following, and Energy Storage*

Smart grid technologies could help coordinate the use of water heaters to: 1) meet peak load; 2) provide regulation and/or load following services; and 3) store energy. In this case, there is enough data to estimate the range of benefits to the power system. For the sake of illustration, it is assumed that the whole resource is available. Although it is unlikely to have full participation, if smart grid controls are installed at the factory, it seems likely that eventually a large percentage of water heaters could be coordinated.

Currently, there are about 3.4 million electric water heaters in the region. If each heater has a heating element of 4,500 watts, the total connected load is about 15,300 megawatts. Of course, water heaters are not all on at the same time; load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5,300 megawatts, depending on the season, day, and hour.

### Controlling Water Heaters to Meet Peak Load

In normal operation, the heating elements of a water heater come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water is gone. This means that heating the replacement water can be delayed, reducing load for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5,300 megawatts, depending on when it is needed.[4]

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[2] One such description of how PHEV could contribute to the power system is at the Regulatory Assistance Project's web site www.raponline.org under the title "Plug-In Hybrid Vehicles, Wind Power, and the Smart Grid."

[3] A common assumption is that this coordination includes a requirement that the charge in the battery at the end of the day is sufficient to get home. Even if this requirement is not met, however, PHEV have the ability to charge their own batteries, so that they are not stranded.

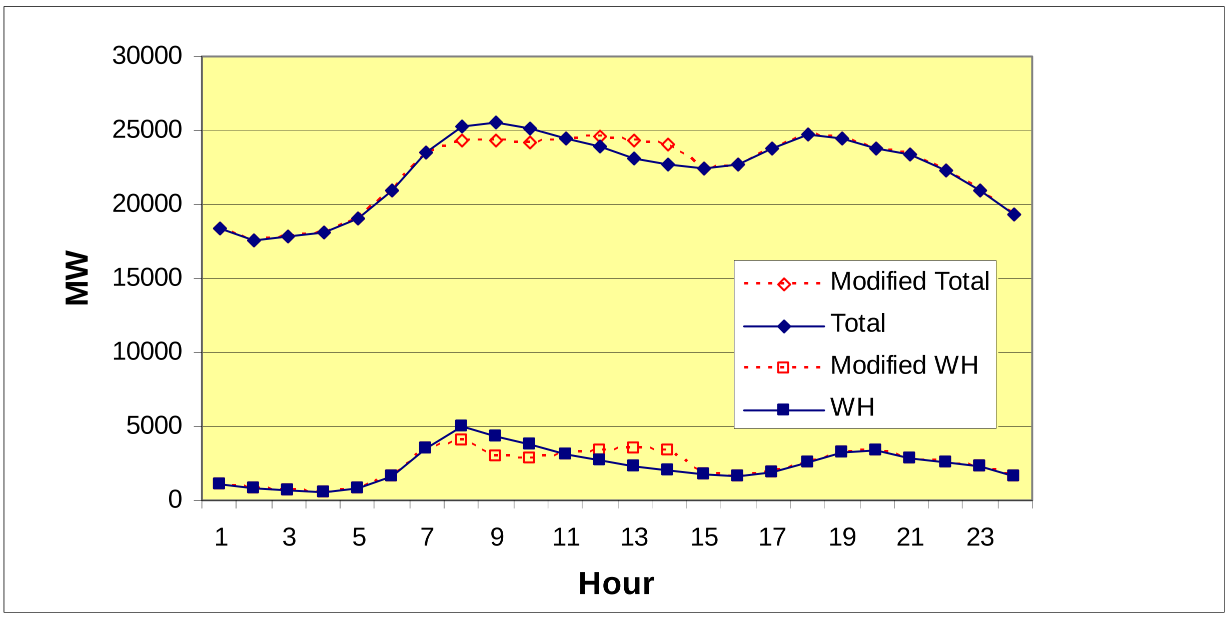
4 Water heating load tends to be high when total load is high, so that the available water heating reductions to help meet peak total load are nearer to 5,300 megawatts than 400 megawatts.

Smart grid technology could sense when water heaters are at risk of running out of hot water and begin heating replacement water, while also postponing heating in other water heaters that still have adequate reserves of hot water. Peak load could be reduced without depriving consumers of hot water when they want it. This reduction could be maintained for a few hours, after which all water heaters would be restored to normal operation, increasing total load while the average temperature in each heater is raised to its normal level. Figure K-1 illustrates the effect of reducing water-heating load on total load, and the recovery of water heaters when the load reduction is no longer needed.

In the figure, the 2010 forecast annual load was combined with 2002 weather to create hourly loads for 2010. Solid lines show the January 4, 2010 hourly forecast loads for both water heating ("WH") and "Total." The broken lines for "Modified Total" and "Modified WH" show the effect of reductions in water-heating load of 1,000, 1,300, and 900 megawatts for the hours between 7:00 a.m. and 10:00 a.m. These reductions would result from delaying reheating of hot water used in those hours. The broken lines then show increases of 700, 1,200, and 1,300 megawatts in the hours from 10:00 a.m. to 1:00 p.m. as water is reheated to return all water heaters to their original average temperatures. The reductions could have been as much as the entire water-heating load, for example, 5,000 megawatts in hour 8 (7:00 a.m. to 8:00 a.m.).

The broken lines illustrate the expected pattern: a reduction in both water-heating and total load, followed by increased load as the water heaters require more energy to restore their original storage temperatures.

**Figure K-1: Peak Reduction Illustration - Controlled Water Heaters**




## Controlling Water Heaters to Provide Regulation or Load Following

Energy users can help the power system by reducing load as shown in Figure K-1, but reductions alone are not enough to keep the system in balance; load must also be increased when the system needs it. These adjustments up or down are referred to as regulation or load following. Water heaters, unlike most other loads, are able not only to reduce load temporarily but can also temporarily increase load as well.

While water heaters are usually set to maintain water at 120 degrees Fahrenheit, they can operate at significantly higher temperatures, and were commonly set at 135 degrees Fahrenheit before the energy crisis of the 1970s. Raising the storage temperature to, for example, 135 degrees Fahrenheit does not increase the total number of gallons of hot water in the tank, but it does increase the total energy stored in those gallons. A mixing valve would ensure that enough cold water is added to the 135-degree water as it leaves the tank to make sure water at the tap never exceeds 120 degrees Fahrenheit for safety concerns.

A water heater that is set at 135 degrees Fahrenheit will provide more gallons of (mixed) 120-degree water than the same tank set at 120 degrees Fahrenheit. Therefore, a water heater with appropriate controls and a mixing valve could accept extra energy from the power system, and store it in the form of higher-temperature water. Then when its hot water is used, the water heater could "return" the energy to the power system in the form of reduced load by heating replacement water only to the original 120-degree setting.

Smart grid technology could enable system operators to control water heaters in both directions in real time, as unscheduled variations in load or generation occur. Water-heating load could, in principle, increase up to the maximum connected load,[5] or decrease down close to zero, but the duration of the increases and decreases would be limited. The duration of load increases would be limited by the allowed rise in water temperature above its normal setting. The duration of load reductions will be limited by the reserves of heated water in the tanks.[6]

Fortunately, regulation and load following require both increases and decreases in load within the hourly operating schedule of the power system. These increases and decreases tend to balance each other over the operating hour. Therefore, these services do not usually require large net increases or decreases over several hours.

## Controlling Water Heaters for Energy Storage

With smart grid controls and communication, water heaters could also act as virtual batteries, storing electricity generated at times when there is little or no demand for it, and releasing it when it has more value. An example of such a condition is 4:00 a.m. during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have few good options – they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

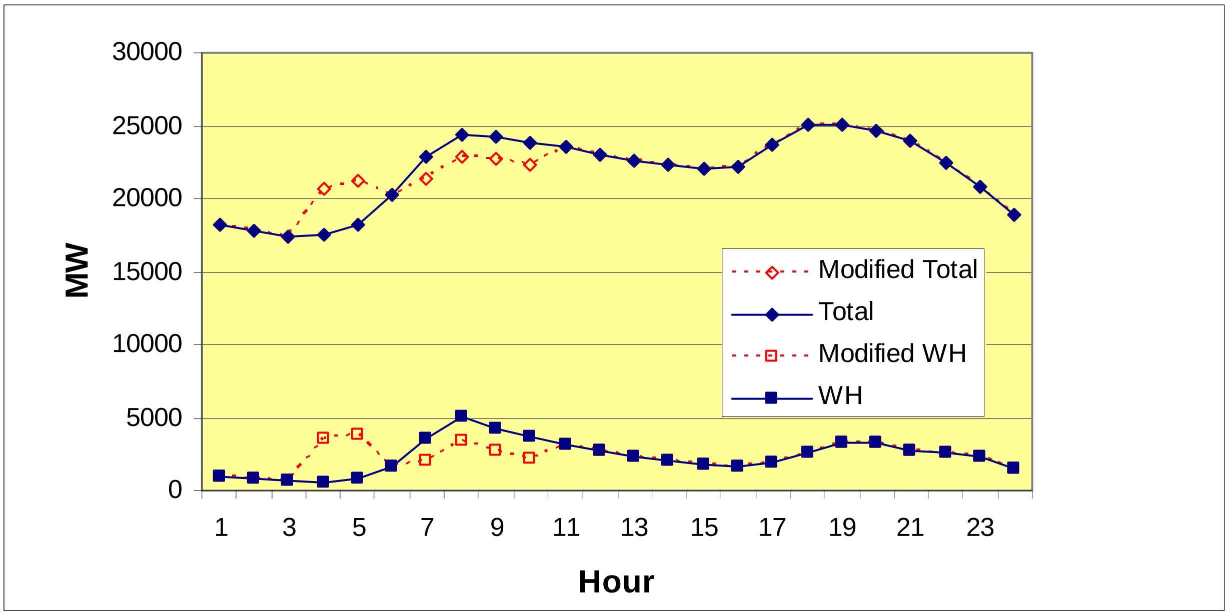
In such conditions, water heaters could absorb extra energy by raising the temperature of stored water and return it to the system by reheating to a lower temperature later. If, for example, the temperature is raised from 120 degrees Fahrenheit to 135 degrees Fahrenheit, 3.4 million 50-

[5] This would imply an increase of 14,900 megawatts in hours when water-heater load is at its minimum (15,300 – 400) or 10,000 megawatts when load is at its maximum (15,300 – 5,300). As a practical matter, the system will never need this much load for regulation or load following, and calling on the full amount could well cause local distribution problems in any case. It's enough to say that several thousand megawatts could be available.
[6] If consumers find themselves without hot water very often, they are likely to withdraw from the program.

gallon water heaters can accept 6,198 megawatt hours[7] of energy and store it at the cost of roughly 24 megawatt-hours per hour from higher standby losses. Figure K-2 is similar to Figure K-1, except that January 2, 2010 loads are used. The “Modified WH” and “Modified Total” broken lines illustrate an increase of 3,099 megawatts in water heating and total load in each of the hours from 3:00 a.m. to 5:00 a.m. and reductions over the hours from 7:00 a.m. to 11:00 a.m. as the water heaters return to their original temperatures.[8]

In contrast to the pattern in Figure K-1 of reductions in load followed by increases, the pattern in Figure K-2 is the opposite -- increases in load as the water heaters absorb the energy to be stored, followed by decreases in load as fewer gallons of cold water need to be heated to 120 degrees Fahrenheit.

**Figure K-2: Energy Storage Illustration**
**Controlled Water Heaters**




The practicality of water heating as a source of load following and/or energy storage depends on the cost of the sensors, communication, and controls that have been assumed in this illustration. It may be that the technology is already sufficiently developed to make load following with water heaters practical if it can be built into the heaters at the factory instead of retrofitted after the heaters are installed in customers’ houses. In that case, the new federal administration’s announced willingness to act aggressively on new appliance standards and to encourage smart grid technologies offers the opportunity to see this possibility become reality.

[7] This rise could result from an increase in load of 6,198 megawatts for an hour, or an increase in load of 3,099 megawatts for two hours, etc. If we allow water temperatures to rise more, water heaters can provide more regulation or load following flexibility.
[8] The return of the energy to the system could be managed to occur later in the day (for example in the high-load hours from 5:00 p.m. to 9:00 p.m.) if that was more useful to the power system. The extra standby losses would amount to about 264 megawatt hours, or about 4.3 per cent of the stored energy.

# ACQUIRING EXPERIENCE WITH THE SMART GRID

There are a number of proposed projects that would give the region increasing experience with smart grid technologies. With funding from the American Recovery and Reinvestment Act (ARRA) the U.S. Department of Energy has awarded grants to Avista Utilities, Central Lincoln People's Utility District, Idaho Power Company, Pacific Northwest Generating Cooperative, and Snohomish Public Utility District to support the purchase and installation of these technologies. U.S. DOE has also awarded a grant to the Western Electricity Coordinating Council (WECC) for similar purposes, which will involve the participation of three regional utilities, Bonneville Power Administration, Idaho Power Company, and PacifiCorp.

U.S. DOE has also funded a proposal by Bonneville, Battelle and 12 partners to demonstrate the practicality and value of smart grid technologies. The total budget of this project is $178 million.

# Appendix L: Climate Change and Power Planning

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## SUMMARY OF KEY FINDINGS

Climate change presents a daunting challenge for regional power planners. There are at least two ways in which climate can affect the power plan. First, warming trends will alter electricity demand and change precipitation patterns, river flows and hydroelectric generation. Second, policies enacted to reduce green house gases will affect future resource choices. There remains a great deal of uncertainty surrounding both of these issues. While the physical impacts of climate change 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 to prepare for potential future impacts. This appendix describes the first of these issues, namely how climate change may affect demand for electricity and production of hydroelectric generation.

Global climate change models all seem to agree that future 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 the Southwest 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 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 late fall or 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 peak to earlier periods in the year;
- Reducing late spring and summer river flows and potentially causing average water temperatures to rise, especially in the tributaries;
- Jeopardizing fish survival, particularly salmon and steelhead, by reducing the ability of the river system to meet minimum flow and water temperature requirements during spring, summer and fall migration and spawning 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.

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.

The effects of the uncertainty surrounding a potential carbon penalty and other climate policies 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 Chapter 11 of the power plan.

# BACKGROUND

Dozens of groups around the world are actively investigating global climate change and its potential impacts.[1] Most of these organizations have developed complex computer models used to forecast long-term changes in the Earth's climate. These models are used primarily to estimate the effect of greenhouse gases on temperature and precipitation. The most sophisticated of these models are known as "general circulation models" or GCMs. They take into account the interaction of the atmosphere, oceans and land surfaces.[2] 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.

Scientists are confident about their projections of climate change for large-scale areas but are less confident about projections for small-scale areas. 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. Forecasts on a global level are of little use to planners in the Northwest. Thus, a

[1] http://stommel.tamu.edu/~baum/climate_modeling.html
[2] http://gcrio.org/CONSEQUENCES/fall95/mod.html

method of "downscaling" the output from these models has been developed.[3] This downscaled data matches better with hydrological data used to simulate the operation of the Columbia River Hydroelectric Power System. By using temperature and precipitation changes forecast by global climate models but 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 to the Northwest hydroelectric power system. Temperature changes lead to adjustments in electricity demand forecasts.

There are at least 20 different global models that simulate future changes in temperature and precipitation. Every one of these models, to varying degrees, projects a warming trend for the Earth. Each uses 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.

# TEMPERATURE AND HYDROLOGICAL CHANGES

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 is projected to 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.

Preliminary downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean (JISAO)[4] Climate Impacts Group (CIG)[5] at the University of Washington. This preliminary data is for a single climate change scenario, which is a composite of results from several climate models used by the CIG and roughly represents an "expected" or average forecast. Results and conclusions provided in this appendix reflect this preliminary composite data set.

The CIG has developed an improved set of data that incorporates a more detailed geographical scale and a wider range of scenarios but unfortunately, it is not yet available in a form that can be used in Council planning models. The CIG is currently adapting results from several of its climate scenarios for use by Council and Bonneville models. The expectation is that a representative subset of scenarios will be modified for Council analysis over the next year or so. This subset of scenarios should adequately represent the full range of projections from all 20 climate models used by the CIG.

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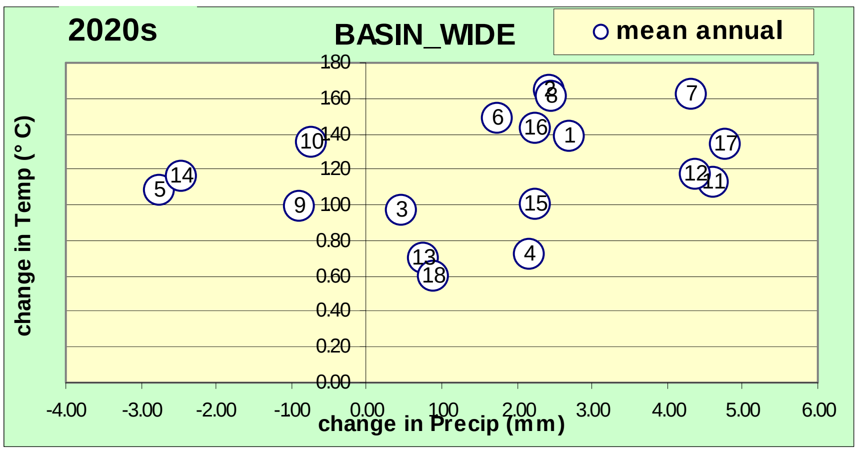
[3] Wood, A.W., Leung, L. R., Sridhar, V., Lettenmaier, Dennis P., no date: "Hydrologic implications of dynamical and statistical approaches to downscaling climate model surface temperature and precipitation fields."
[4] http://tao.atmos.washington.edu/main.html
[5] http://tao.atmos.washington.edu/PNWimpacts/index.html

A summary of forecasted annual temperature and precipitation changes from the 20 global climate models used by the CIG (for the 2020 time period) is shown in Figure L-1.  In this figure, the X-axis represents change from current conditions in annual precipitation (in millimeters) and the Y-axis represents change in annual temperature (in degrees Centigrade). Each point in this figure represents the average precipitation and temperature change for each climate change scenario studied by the CIG.  For example, the point labeled number 3 indicates that for the CIG climate scenario number 3, the average annual precipitation is forecast to be about 0.5 millimeters greater and the average annual temperature is forecast to be about 1 degree Centigrade greater.  Three conclusions can be drawn from the results in this figure; 1) each model shows a net temperature increase, 2) most but certainly not all models show a slight increase in annual precipitation, and 3) there is great variation in both the temperature and precipitation forecasts.

**Figure L-1:  Columbia Basin Temperature and Precipitation Change Forecasts**[6]




Unfortunately, the detailed hydrologic data required to run the Council's hydroelectric simulation model was not available for any of the scenarios plotted in Figure L-1.  Consequently, analysis in this appendix is based on a preliminary CIG climate change scenario, whose temperature and precipitation changes fall "somewhere in the middle of the pack" according to their staff.  The other unfortunate thing about this scenario is that it was developed for the 2040s period, which is beyond the scope of this power plan's study horizon (2030).  The temperature and streamflow changes forecast in this scenario were assumed to occur in 2045 and were then interpolated back into the 2010 to 2030 study horizon period.  Thus, the analysis in this appendix is presented only as a preliminary assessment of potential impacts to river flows, hydroelectric generation and cost.

Other caveats regarding the analysis in this appendix are specified below:

- Climate-change adjusted stream flows were based on a 69-year water record (1930 to 1998) instead of the 70-year record (1929 to 1998).

[6] Taken from the River Management Joint Operation Committee's preliminary summary of the University of Washington Climate Impacts Group's Global Climate Model analyses for the Northwest (RMJOC_Task1.2_ExploreScenariosSpread_v2.xls).

- No correlation was assumed between temperature increases and river flows, that is, only a single monthly temperature increase was assumed for each water condition.

- Operating guidelines (rule curves) for the hydroelectric system were not adjusted (i.e. flood control was not adjusted for the change in spring runoff forecast nor were firm drafting limits re-optimized).

- Each water condition was given an equal likelihood of occurring.

## *Precipitation, Snow Pack, and 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. More rain in winter months means higher stream flows during those months. However, with a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows in summer. In addition, the peak of the spring runoff is projected to occur as much as a month earlier. Figure L-2 shows monthly average river flows at The Dalles Dam based on the historical record and the effect of climate change to those flows. Figure L-3 highlights the impact by plotting the change in average flow at The Dalles Dam by month.

While these changes are drastic (i.e. a flow reduction of over 100,000 cubic feet per second in June) they are not expected to occur until 2045. As will be demonstrated in a later section, annual changes to temperature and consequently river flows from today through 2045 are expected to grow gradually and in a non-linear fashion (changes growing more rapidly later in the period). In fact, climate induced changes to annual river flow in the near term are difficult to detect due to the large natural variance in annual weather patterns. The effect on regulated flows for the year 2030 is provided in Figure L-8 below, in the section entitled "Impacts to the Power System."

**Figure L-2: Average Unregulated Flow at The Dalles (2045)**

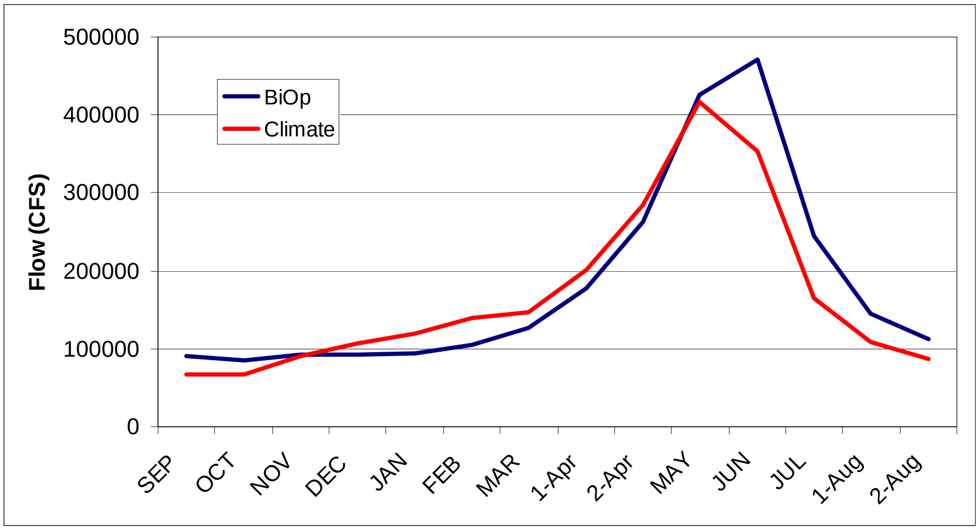
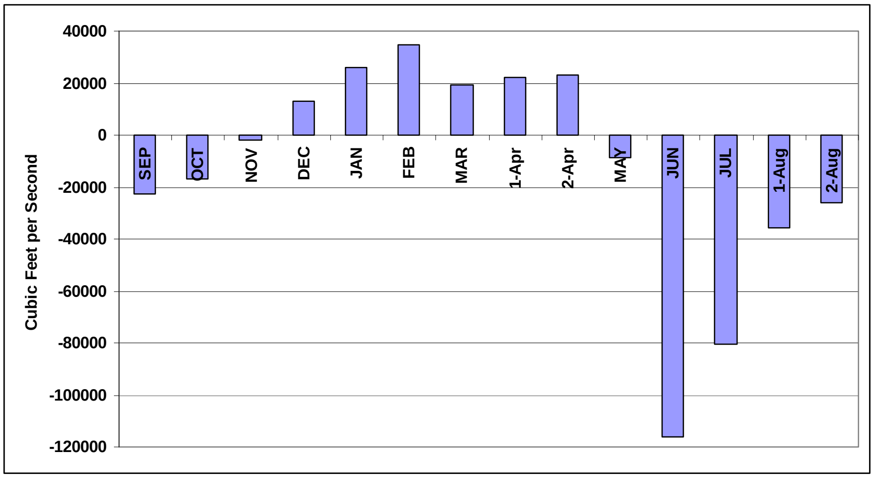


**Figure L-3: Forecast Change in Unregulated Flow at The Dalles (2045)**




## *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 two-degree increase in average temperature over winter months should translate into about a 600-megawatt decrease in electricity demand.

However, the Council does not rely on the Power Pool to estimate fluctuation in demand caused by temperature changes. The Council uses a recently developed load model to assess demand variations as a function of temperature. Results of that relationship are presented in Figures L-4 and L-5. Results from the Council's model show that a two-degree increase in the average monthly temperature for December results in about a 600 average-megawatt decrease in regional load – essentially the same conclusion that the Power Pool would make. However, that relationship doesn't hold up in January, when a two-degree increase in temperature yields just over a 400 average-megawatt decrease in load.

It should be noted that the Power Pool's rule-of-thumb temperature/load relationship is primarily focused on peak hourly loads and not on monthly average loads. For an average *monthly* increase in temperature of two degrees in winter months, the associated average *peak hourly* temperature will be higher. From Figure L-4, a two-degree increase in monthly temperature for December yields a peak hourly load decrease of just over 1,000 megawatts. If the Power Pool's relationship holds, this means that the average change in the peak hour temperature should be a little over three degrees.

Summer loads appear to be a little more sensitive to temperature than winter loads. Again using the results plotted in Figures L-4 and L-5, a slightly lower than three degree increase in the average July temperature (see Figure L-7) results in an average monthly load increase of over 1,000 average megawatts and a peak hour load increase of nearly 3,000 megawatts.

**Figure L-4: Impact of an Annual 2-Degree Temperature Increase on Peak Loads**

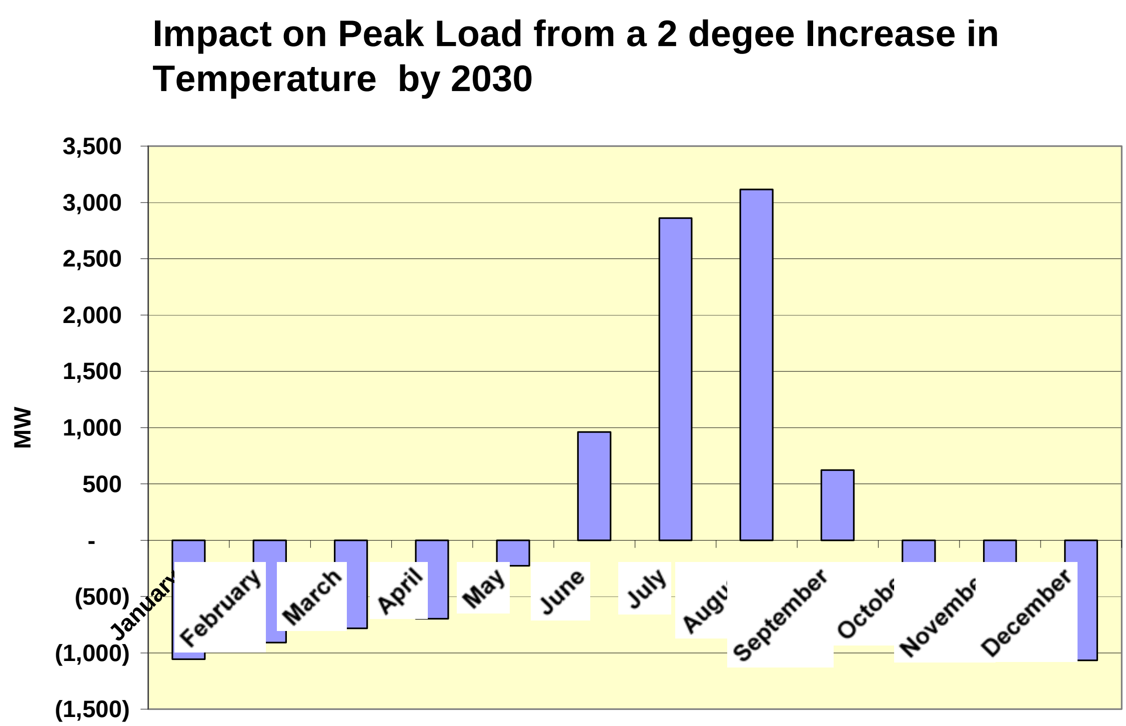
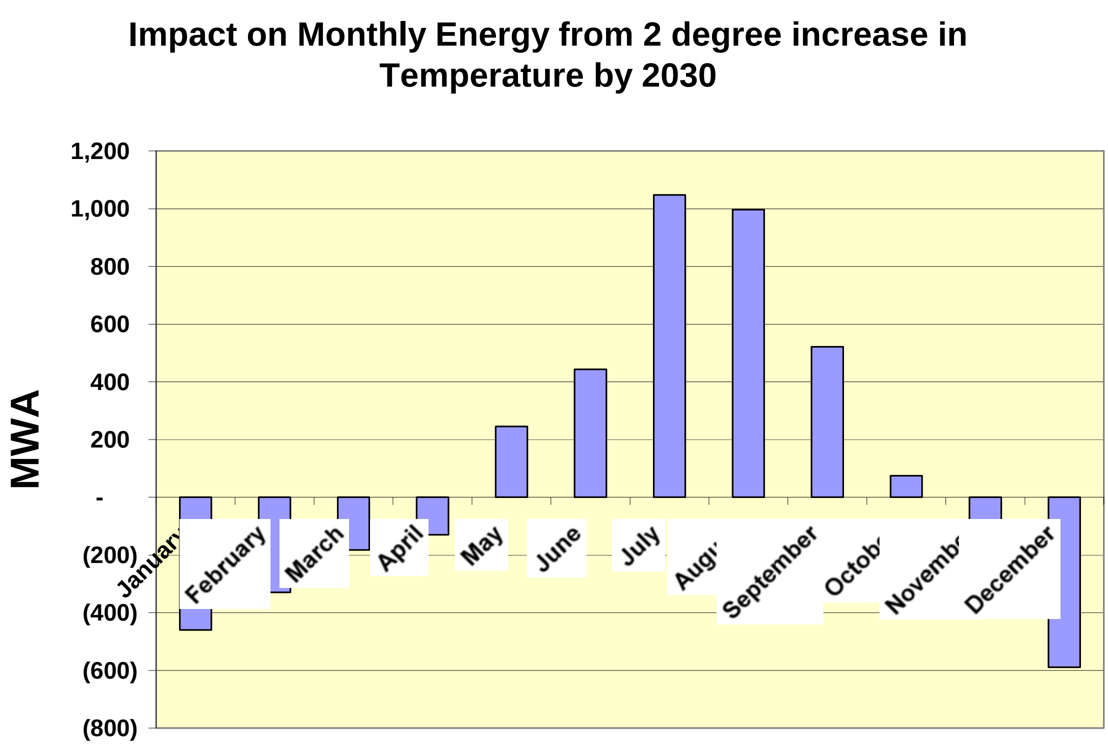
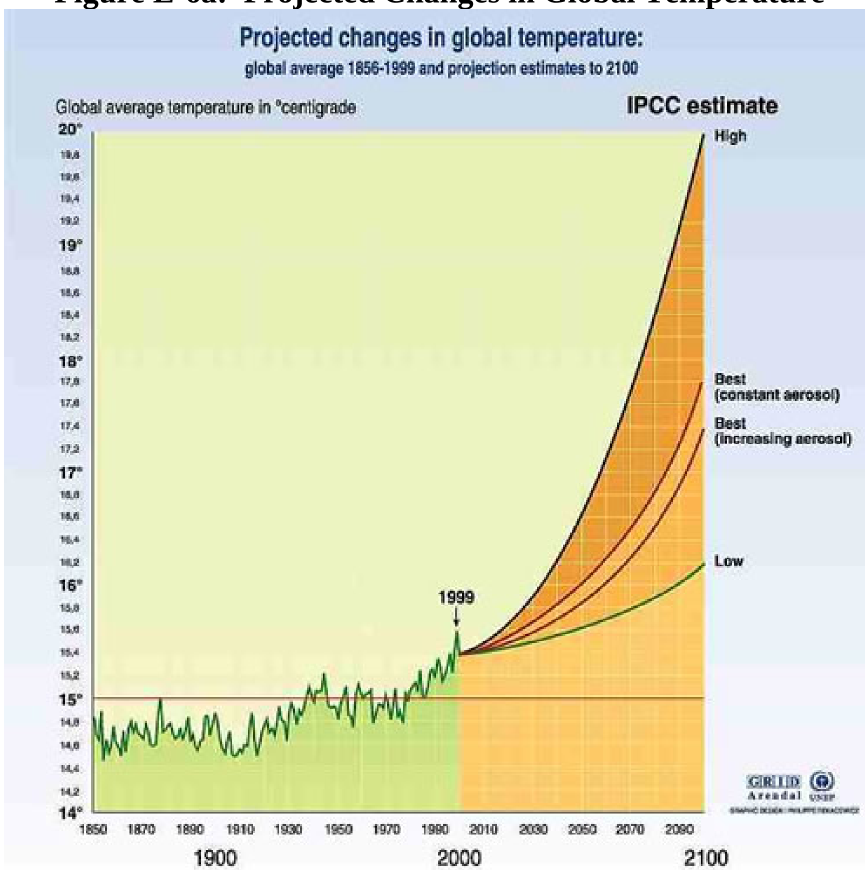



**Figure L-5: Impact of an Annual 2-Degree Temperature Increase on Monthly Loads**



Using preliminary data from the University of Washington, the projected increase in annual temperature caused by climate change was interpolated to be about 2 degrees Fahrenheit by 2030. However, this forecast temperature increase is not expected to grow linearly. Based on current data used in global climate models, it appears that climate induced temperature increases should grow gradually, as illustrated in Figure L-6a. This general trend for global temperature increase was used to derive a projected annual temperature change for the Northwest. Those results are shown in Figure L-6b. In addition, annual temperature increases are not distributed uniformly across each month of the year. Figure L-7 shows the monthly distribution of temperature change for an annual increase of 2 degrees.

**Figure L-6a: Projected Changes in Global Temperature**




*Actual global temperatures are plotted on the graph for years 1856-1999 and IPCC estimates of temperature are plotted for years 1999-2100. Different lines on the graph between 1999 and 2100 indicate high, low, and best estimates of future temperature.*

Courtesy GRIDA/UNEP

**Figure L-6b:  Projected Climate Induced Annual Temperature Change through 2030**

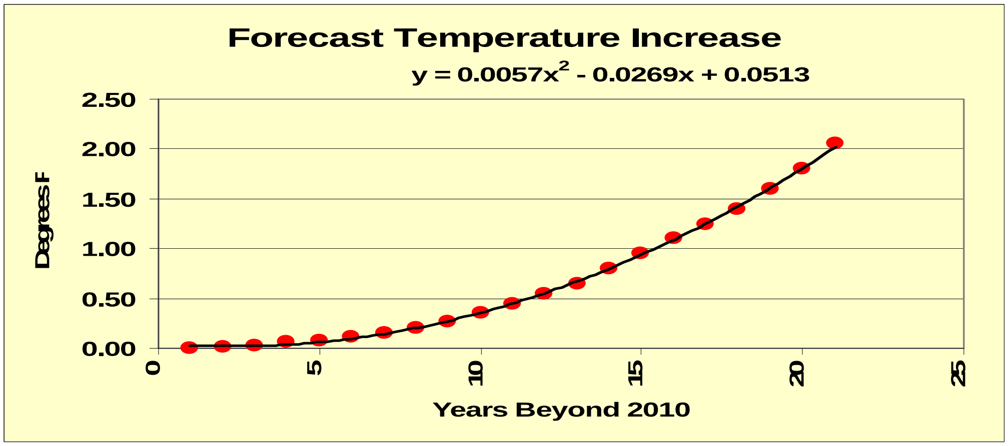
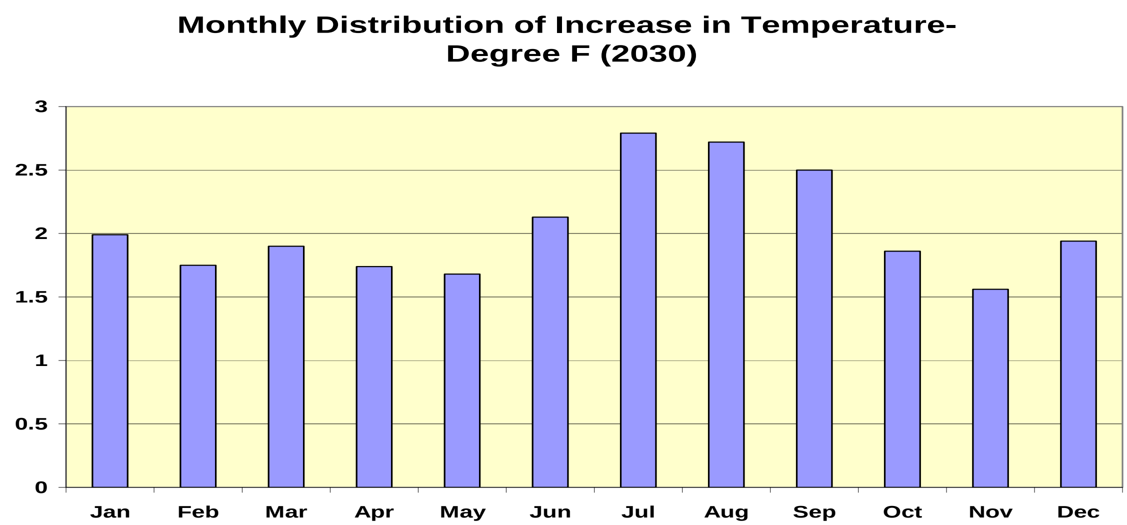



**Figure L-7:  Projected Changes in Monthly Average Temperatures by 2030**




The projected increases in annual and monthly temperatures are converted to cooling and reduced heating degree days for each state. The cooling and heating degree days are measured as the average of annual cooling or heating degrees days for years 1985 through 2007. The cooling and heating degree days vary by state.  For example, under normal conditions, the annual cooling degree day value for state of Idaho is about 531 degrees.  In the preliminary climate change scenario, the normal cooling degree days is forecast to increase to 904 degrees by 2030.  Each state's normal and 2030 forecast cooling and heating degree day values are shown in Table L-1 below.  The summer cooling degree days is projected to increase at an average annual rate of 1.6 percent and the winter heating degree days is declining at an average annual rate of -0.3 percent.

**Table L-1:  Cooling/Heating Degree Days by State**

| | Cooling Degree Days (Normal) (1985-2007) | Cooling Degree Days (2030) | Heating Degree Days (Normal) (1985-2007) | Heating Degree Days (2030) |
|---|---|---|---|---|
| **ID** | 531 | 904 | 6589 | 5788 |
| **MT** | 290 | 500 | 7826 | 6875 |
| **OR** | 271 | 468 | 4927 | 4328 |
| **WA** | 221 | 381 | 5277 | 4635 |

As a result of climate induced increases in temperatures, the annual demand for energy is forecast to increase by 120 average megawatts by 2030.  However, that conclusion is somewhat misleading since the resulting January and December load is expected to decrease on the order of 400 to 600 average megawatts, while the July and August load is expected to increase by about 1,000 average megawatts for each month.

Regional summer peak load is projected to increase by over 3,000 megawatts by 2030, while the winter peak load is expected to decline by about 1,000 megawatts.  The impact of temperature on summer and winter loads, especially peak hourly loads, is not equivalent because of the assumed penetration rate of air-conditioning and space heating.  Air-conditioning penetration rates continue to increase over time, while the penetration rate of space heating is already at 100 percent.

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.  Based on current assessments of power supply adequacy (Chapter 14), the existing power system can adequately serve additional climate induced demand but only in the near term.  With continued demand growth, especially in summer, and increasing operating constraints on the hydroelectric system, it appears that by 2013 the region may be faced with an inadequate summer supply.  Adding conservation and wind resources, as proposed by this power plan, extends the period of adequacy for the region and will give planners more time to assess climate impacts and actions to mitigate for them.

# IMPACTS TO THE POWER SYSTEM

## *Methodology*

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[7] computer model is a Monte Carlo program that simulates the operation of the Northwest's 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.

[7] See www.nwcouncil.org/GENESYS

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 stream flows, 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 simulated future year, it samples a particular runoff condition, a set of daily temperatures and the availability of thermal generating units, all according to their assumed likelihood of occurrence.

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, 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 margin 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.

## *Hydroelectric Generation and Cost*

More rain in winter months means higher stream flows at a time when electricity demand is highest.  This in combination with 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 reexamine 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 during that time.

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 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, which would also decrease the peaking capability.  The projected increase in Northwest summer demand along with potential reductions in hydroelectric generation will force the Northwest to consider resource options for summer needs sooner rather than later.

Figure L-8 shows the expected average *regulated* flow changes in 2030 due to climate impacts. This chart shows a similar pattern to that in Figure L-3, which shows the expected differences in *natural* (or unregulated) flows for 2045.  Hydroelectric generation is proportional to river flow, thus it is no surprise that the average change in hydroelectric generation for 2030 (as shown in Figure L-9) has the same monthly shape.

It should be noted that this analysis was performed without modifications to operating rule curves, such as those for flood control.  The effect of this is to exaggerate projected flow reductions in summer.  Because future snow packs are forecast to be smaller, using current flood control elevations in the climate change scenario will evacuate reservoirs to a greater degree than necessary.  Thus, reservoirs in that scenario are emptier by the end of June.  Had flood control elevations been adjusted, end-of-June elevations should have remained unchanged from the base case.

Because our analysis did not adjust flood control rule curves, the projected summer flow reductions in Figure L-8 are overestimated.  The magnitude of the error for summer flow changes can be approximated by assuming that the difference in the end-of-June reservoir content is released uniformly over the summer months in the climate scenario.  Making this adjustment decreases summer flow reductions by about 10 percent. It should be noted that forecast changes in generation, as shown in Figure L-9, and in cost, as shown in Figure L-14, also do not reflect this adjustment.

The effects of climate change on flood control and other rule curves is currently being addressed by the River Management Joint Operating Committee (RMJOC), which is discussed in more detail later in this appendix, in the section entitled “Modeling Climate Change as a Random Variable.”

**Figure L-8:  Projected Regulated Flow Changes at The Dalles Dam (2030)**

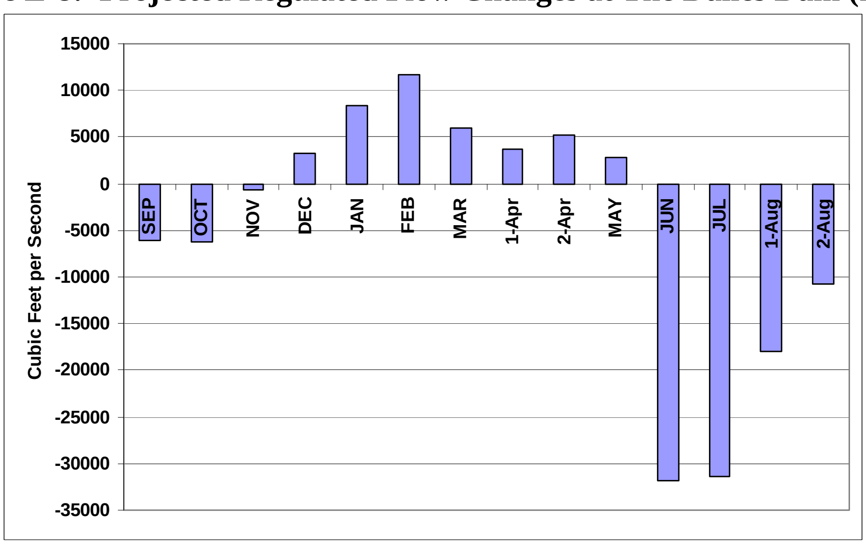
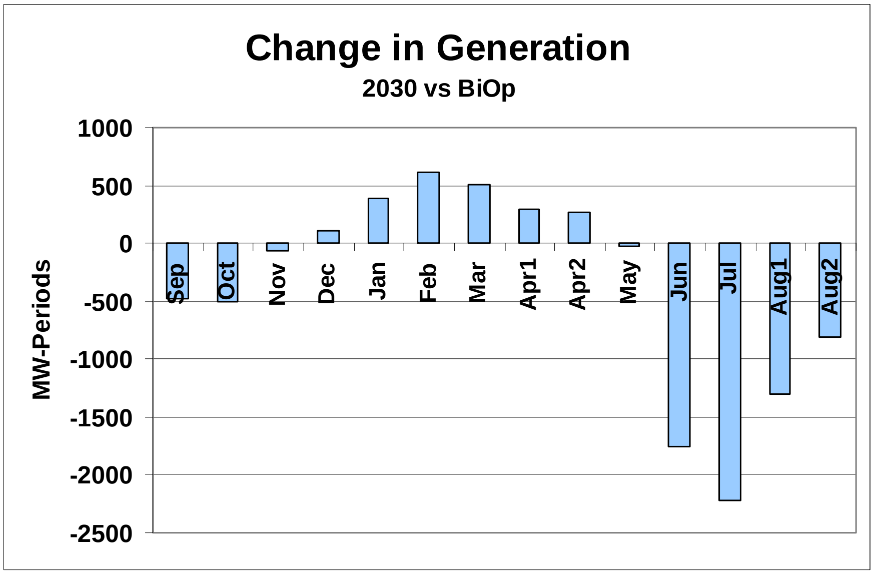
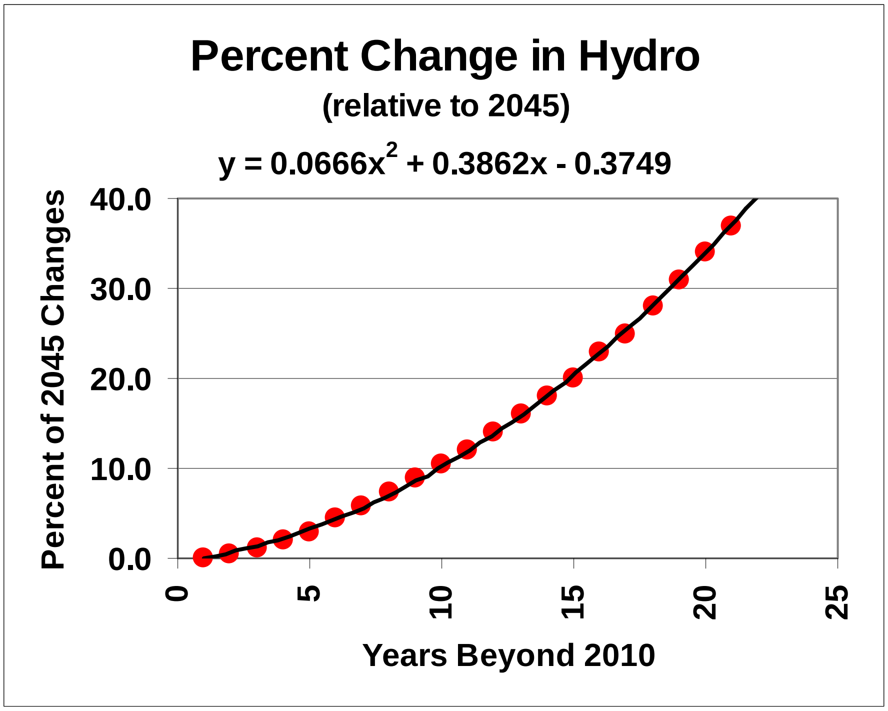


**Figure L-9: Change in Hydroelectric Generation for 2030**




As with projected temperature increases over time, river flow changes will also occur gradually. Figure L-10 illustrates the assumed changes to hydroelectric generation through 2030. It should be emphasized that the curve in Figure L-10 does not imply that hydroelectric generation will grow over time. What it does reflect is that portion of the 2045 change in generation that is expected in the years between 2010 and 2030. Climate change data that was actually analyzed was for the year 2045 and included the natural flow adjustments (as illustrated in Figure L-2). As with the temperature changes over time, an assumption was made that natural flow changes (and thus hydroelectric generation changes) would occur gradually. The generation changes in question are similar to those shown in Figure L-9 but reflect values for the year 2045. Figure L-10 indicates what percent of the 2045 change occurs in any given year, whether the (monthly) change is positive or negative. In fact, the data for Figure L-9 was derived by taking the average monthly generation changes for 2045 and applying a factor of about 37 percent (the value in Figure L-10 for year 2030).

**Figure L-10: Projected Annual Hydroelectric Generation Change Relative to 2045**




Using the above mentioned assumption regarding climate change impacts to hydroelectric generation, we derive the data for Figures L-11 and L-12. Those figures show the expected change in average hydroelectric generation for July and February over the study horizon period. By 2030, average February generation is expected to increase by about 600 average megawatts or about 4 percent. July generation is expected to decrease by about 2,200 average megawatts or about 17 percent.

**Figure L-11: Average Winter and Summer Hydroelectric Generation Change**

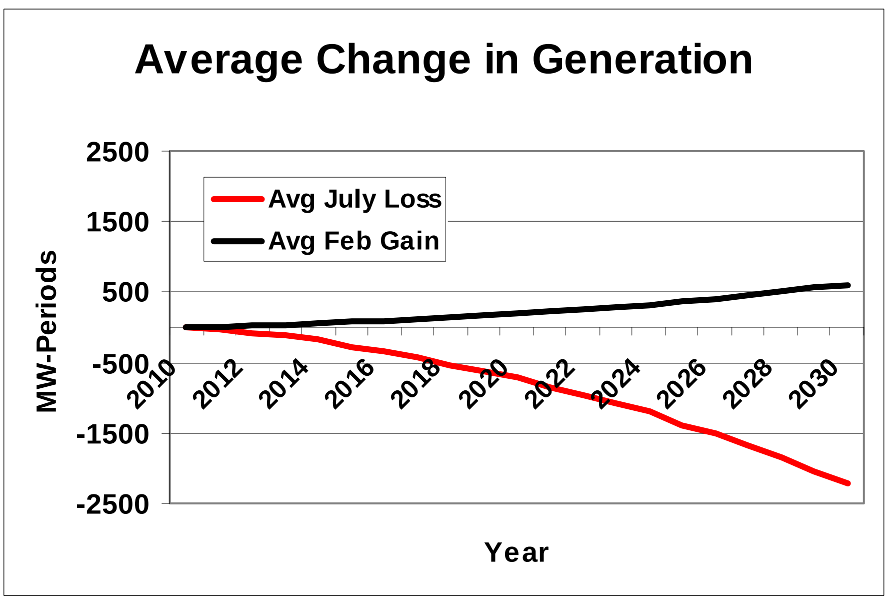
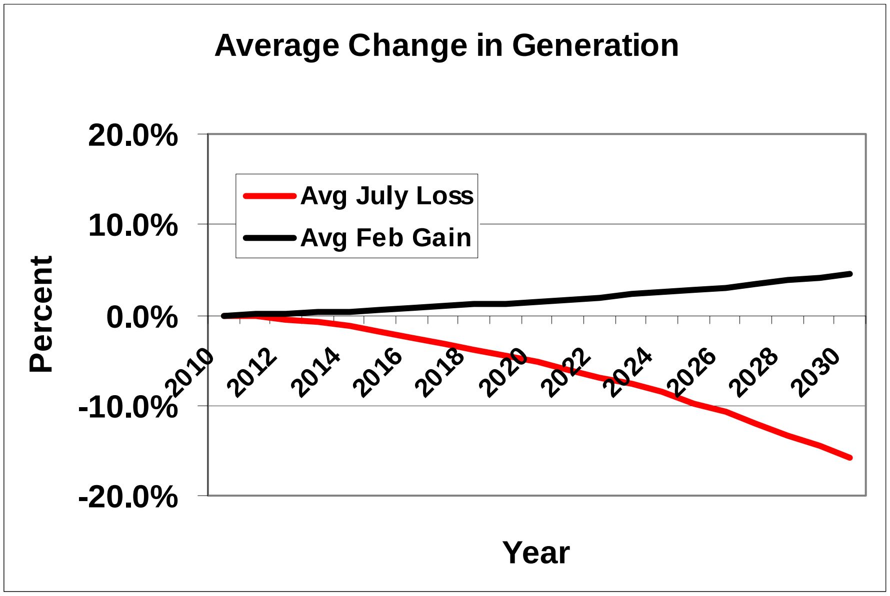


**Figure L-12:  Percent Annual Hydroelectric Generation Change**



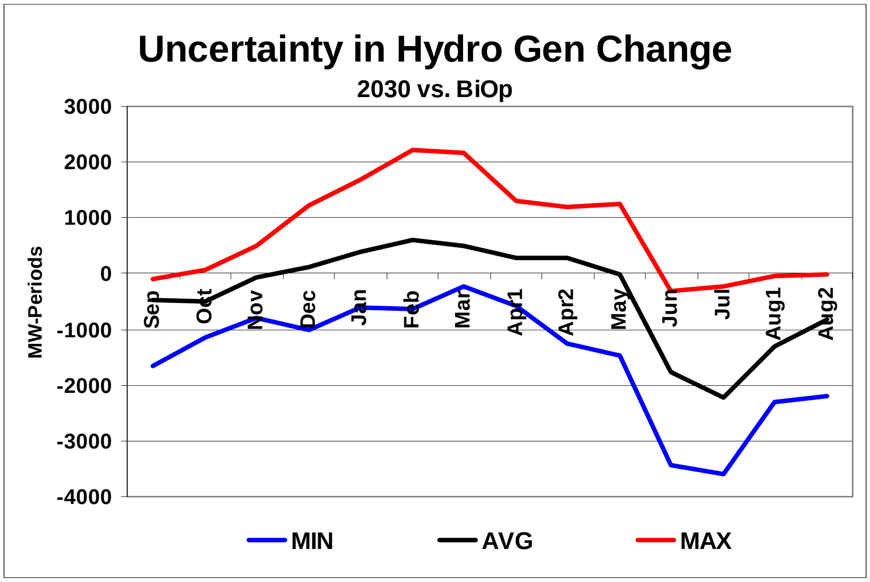

At the same time, winter demand is expected to decrease by about 600 average megawatts by 2030 while summer demand is expected to increase by about 1,000 average megawatts.  Table L-2 summarizes these results, which when added together show a net load/resource balance increase of 1,200 average megawatts in winter and a net load/resource balance decrease of 3,220 average megawatts in summer.  From an adequacy point of view, the winter season gets better while the summer becomes more stressed.  In principle, these load/resource balance differences can be used to adjust the adequacy assessment calculations in Chapter 14.  The net effect of doing so does not change the conclusion in that chapter, which is; that on an annual energy basis the region's power supply is adequate.  A similar assessment of changes in winter and summer peaking reserve margins can be done and applied to the assessed values for peaking supply adequacy.  This has not be done for a number of reasons but primarily because the climate change data used for this analysis is preliminary and is too uncertain to use for resource planning at this time.  However, it can be concluded that all climate change scenarios will make the summer peaking situation worse.

**Table L-2:  Net Impacts to Energy Load/Resource Balance 2030 (MWa)**

| Changes to: | Winter | Summer |
|---|---|---|
| **Generation** | 600 | (2,220) |
| **Demand** | (600) | 1,000 |
| **Net (G-D)** | 1,200 | (3,220) |

Assessing the true power system cost of climate change is difficult because in order to do so would require the development of two complete resource plans; one with climate change and one without.  The Council's Portfolio Model does not currently have the capability to incorporate climate change impacts to hydroelectric generation and load as random variables.  (This topic is discussed in more detail in the last section).  However, an approximate power system cost can be made by assuming that changes in hydroelectric generation are priced at market values.  Thus, months showing higher generation represent a net benefit to the region and months with lower generation represent a cost.  In principle, generation changes for each month and for each water condition would be priced at the corresponding market electricity price (which varies by month and water condition).  The uncertainty in the change in hydroelectric generation is illustrated in Figure L-13, which captures the minimum, maximum and average generation for each month.

**Figure L-13:  Uncertainty in Climate Induced Generation Change**




In wet years, like the maximum curve in Figure L-13, the region stands to make money.  And conversely in dry years, like the minimum curve, the region will likely have to purchase from the market to serve all of its loads.  The average or expected cost of this scenario is on the order of $120 million dollars for 2030 climate conditions (but priced at today's prices).  Figure L-14 shows the monthly distribution of costs, which has a similar pattern as the generation change chart (Figure L-9) and the flow change chart (Figure L-8).  Applying the minimum and maximum ranges for changes to hydroelectric generation yields the graph in Figure L-15, which shows the range of potential power system costs for this scenario.

Even though a power system cost can be estimated using these techniques, no serious conclusion can be drawn as to whether climate change will be an economic benefit or cost to the region. There remains too much uncertainty in the data to make that assessment.  We can conclude, however, that the net benefit or cost is directly related to the total volume of water that flows through the hydroelectric system on an annual basis.  That parameter appears to be more important in assessing costs than the volume of water that is shifted from summer to winter.

**Figure L-14: Estimated Power System Cost of Climate Change**

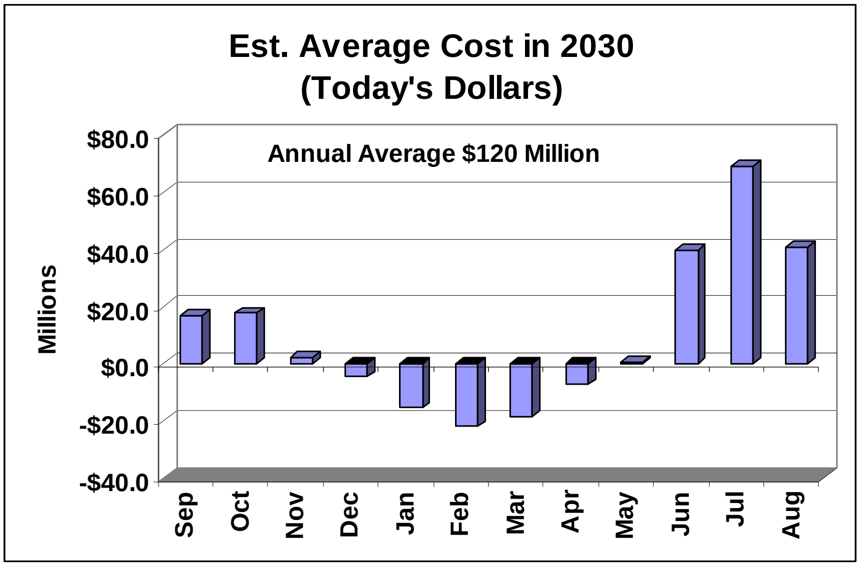
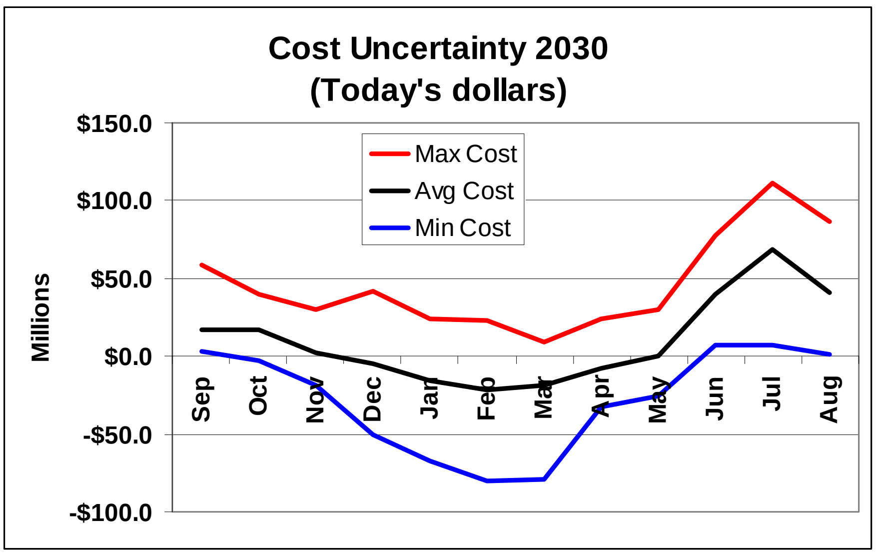



**Figure L-15: Climate Change Cost Uncertainty**




## *Other Impacts*

Because river flows are likely to decrease in spring and summer, 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 combined with a higher air temperature also means that water temperature may increase, another factor contributing to salmonid fish stress and mortality.

Besides the impacts to river flows, hydroelectric generation and temperatures, climate change will affect the Northwest's electricity 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 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.

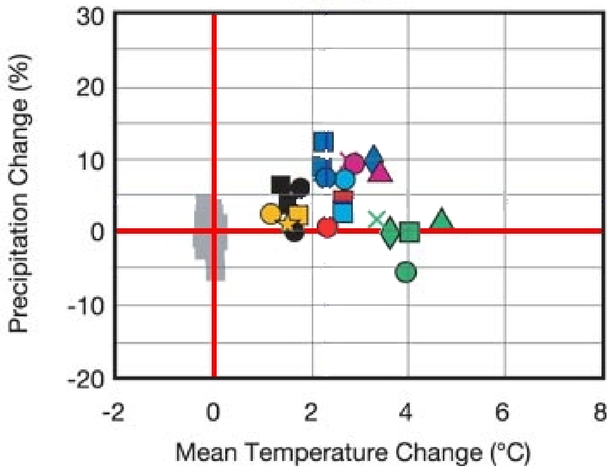
All of these impacts assume that no operational changes are made to the hydroelectric system.  As described below in the section on mitigating actions, changes in the operation of the hydroelectric system may be significant.  In which case, the impacts mentioned above may become better or worse.  For 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.

# MODELING CLIMATE CHANGE AS A RANDOM VARIABLE

Ideally, climate change uncertainty and its impacts to hydroelectric generation and loads would be included as one of the random variables in the Council's Portfolio Model.  Unfortunately, this cannot be done at this time for several reasons.  First, the data required to do so is not available.  Second, even if the data were available, the Portfolio Model is not equipped to accommodate it.  Third, the relative likelihood of occurrence for each of the scenarios analyzed by the 20 Global Climate Models is not known.

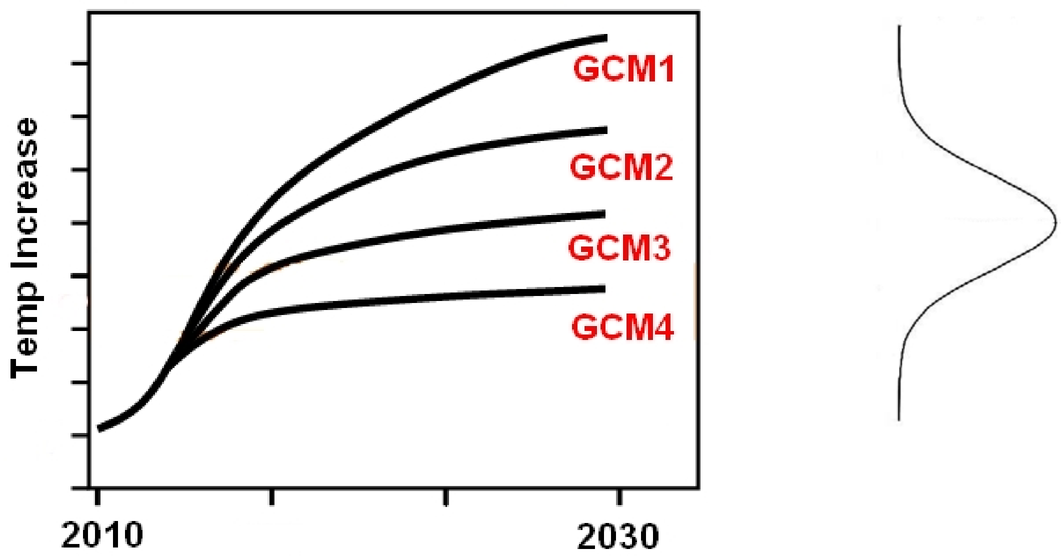
Figure L-16 below (similar to Figure L-1) illustrates the mean forecasted temperature and precipitation changes for a number of climate change scenarios.  The data in Figure L-16 is not representative of analyses for the Northwest but rather is simply an illustration of the uncertainty surrounding these models.  Each point in this graph represents the result of a single climate change scenario analysis for a particular future year.  The gray area in this graph represents the normal uncertainty range for current climate conditions.  Not surprisingly, the uncertainty in the climate change analyses (measured as the size of the spread of points) is much larger than the uncertainty surrounding current climate.  As noted previously, all scenarios show a higher forecasted temperature but not all forecast higher precipitation.

**Figure L-16: Illustration of Temperature and Precipitation Changes for Various Models**




Recall (from Chapter 9) that the Regional Portfolio Model is a Monte Carlo computer program that assesses average power system cost and economic risk for many different resource plans. Each resource plan is, in essence, a potential supply curve of available new resources, including conservation, over the study horizon period. Each resource plan is examined over many different potential futures for the Northwest. Each future covers a 20-year period and draws from many random variables, including load, hydroelectric generation (water condition), electricity prices, fuel prices and carbon penalties to assess costs. In order to incorporate climate change uncertainty into the model as a random variable, the relative likelihood of occurrence for each climate scenario must be known. Then for each future examined, one particular climate change profile would be selected (i.e. one of the points in Figure L-16) as one of the many random variables used for that particular future. This concept is illustrated graphically in Figure L-17. In this figure, the mean forecasted temperature increase per year over a 20-year period is plotted for several different climate change scenarios (GCM1 through GCM4). In this example, a probability distribution is assigned to the set of scenarios, shown as the bell curve to the right of the graph. In this example, GCM2 and GCM3 are more likely to occur than GCM1 or GCM4 and thus they would be selected more often in the Monte Carlo simulation. Probability distributions for Northwest climate change scenarios, however, have not yet been developed.

**Figure L-17:  Illustrative Probability Distribution for Climate Model Results**




Unfortunately, that is not the only problem that has to be overcome in order to incorporate climate change as a random variable into the Portfolio Model.  Once a climate scenario is chosen by the model, its long-term effects on load and on hydroelectric generation will have to be interpolated back into the 2010 to 2030 study horizon period.  Methods for performing that interpolation have not been extensively explored, although an example of one method has already been discussed earlier in this appendix.

But in spite of these difficulties, progress is being made.  The Bonneville Power Administration, the Corps of Engineers and the Bureau of Reclamation have initiated a regional process to collect, review and make available all climate change data related to river operations.  This process is being developed under the auspices of the RMJOC and will ultimately result in a web-based database that will include CIG data along with other related data needed to perform river operation analyses.  Among other things, the additional data will include climate-change adjusted runoff forecasts and operating rule curves.  The Council supports this work and will actively participate in its development.

# RECOMMENDATIONS

The development of this power plan for the Northwest incorporates actions intended to address future uncertainties and their risks to electricity supply and to the economy.  Such uncertainties include fluctuations in demand, fuel prices, changes in technology and increasing environmental constraints.  Uncertainties related to climate change fall into two areas; 1) physical impacts that affect electricity demand and hydroelectric generation and 2) policies directed at reducing green house gas emissions that affect resource operation and cost.

Though the physical effects of climate change remain imperfectly understood, the Council has examined them and recommends that research continue in this area.  In terms climate policy, the

Council has explicitly included assumptions regarding potential carbon penalties and renewable resource portfolio requirements into its Portfolio Model.  A more detailed description of those policies and their impacts is provided in Chapter 11.

While no immediate actions regarding reservoir operations are indicated by this preliminary analysis of the physical impacts of climate change, the region should begin to examine and consider alternative reservoir operations that could potentially mitigate those impacts. Some of those actions may include:

- Adjusting reservoir rule curves to assure that reservoirs are full by the end of June
- Allowing reservoirs to draft below current end-of-summer limits
- Putting more effort into developing better runoff forecasting methods for the fall
- Negotiating with Canada to examine the potential for more summer releases from Canadian reservoirs
- Using increased winter streamflows to refill reservoirs
- Exploring the development of non-hydro resources to replace winter hydroelectric generation and to satisfy higher summer needs.

# Appendix M: Integrating Fish & Wildlife and Power Planning

Summary of Key Findings ........................................................................................................ 1
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The 2009 Fish and Wildlife Program and Current Fish Operations .......................................... 5
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## SUMMARY OF KEY FINDINGS

The Columbia River Basin hydroelectric system is a limited resource that is unable to completely satisfy the demands of all users under all circumstances.[1] Conflicts often arise that require policy makers to decide how to equitably allocate this resource. The Council's *Columbia River Basin Fish and Wildlife Program* and *Electric Power and Conservation Plan* must provide measures to "protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of [hydropower] facilities while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply."

The regional power supply has reliably provided actions specified to benefit fish and wildlife (and absorbed the cost of those actions) while maintaining an adequate, efficient, economic and reliable energy supply. This is so even though the hydroelectric operations specified for fish and wildlife have a sizeable impact on power generation. The Council's current assessment[2] indicates that new resources and conservation are required to maintain the power supply's adequacy, in particular for summer peaking needs.

On average, hydroelectric generation is reduced by about 1,200 average megawatts, relative to an operation without any constraints for fish and wildlife.[3] For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability.[4] Since 1980, the power system has addressed this impact by acquiring conservation and generating resources, by developing resource adequacy standards, by implementing strategies to minimize power system emergencies and events that might compromise fish operations, and by using revenues generated by the system to cover costs. As described at the conclusion of Chapter 13,

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[1] Some of the many uses of the Columbia River hydroelectric system include flood control, power generation, irrigation, recreation, navigation and protection for fish and wildlife.
[2] See Chapter 14.
[3] The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.
[4] Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.

Bonneville estimates its total financial obligation for the fish and wildlife program to be between $750 to $900 million per year, combining ordinary and capital expenditures, power purchases, and foregone revenues associated with operations to benefit fish and wildlife (when compared to a scenario with no such operations). Increased costs and reduced revenues due to operations for fish result in increased electricity prices, but the power system remains economical in a broad affordability sense.

Looking toward the future, there remain a number of uncertainties surrounding the operation of the hydroelectric system, which must be addressed in the development of the power plan. These uncertainties can have both positive and negative effects. For example, spillway weirs offer the potential to reduce bypass spill while providing the same or better passage survival. On the other hand, current bypass spill levels may change due to adaptive management or litigation. Climate change has the potential to alter river flows, which affect both power production and fish survival. The potential of dam removal or of operating reservoirs at lower elevations would further reduce power production. The Council recommends that the region continue to monitor fish and wildlife activities and to continue to develop better analytical methods to assess both power and biological impacts.

Outside of the Council's own power planning effort, there is no forum or process in the region that specifically addresses long-term planning issues related to the integration of power planning and fish and wildlife operations. The Council will investigate using existing forums to facilitate such discussions or, if necessary, explore the possibility of creating a separate forum where fish and wildlife managers and power planners could jointly explore longer-term strategies to improve both fish and wildlife benefits and hydroelectric power operations. In such a forum, synergistic effects between fish and wildlife operations and power planning could be examined.

# INTEGRATING THE FISH AND WILDLIFE PROGRAM AND POWER PLANNING UNDER THE NORTHWEST POWER ACT

The many storage and hydroelectric facilities built in the Columbia River Basin provide a number of benefits to the citizens of the Pacific Northwest and Canada. This includes the fact that, on average, the US portion of the hydroelectric system provides nearly 75 percent of the electricity needs for the northwest.[5] Development of the hydroelectric system, however, has also had adverse effects on salmon and steelhead and other native species of fish and wildlife in the basin. In the Northwest Power Act, Congress directed the Council to lead an on-going effort to find the best ways to operate the hydrosystem and further develop the region's power supply so as to improve the survival of fish and wildlife affected by the system while also meeting the region's growing electricity demands with the least-cost conservation and generating resources.[6]

The Northwest Power Act directs the Council to integrate planning for fish and wildlife and electric power resources in a recurring two-step planning process. The first step is to develop or amend the fish and wildlife program; the second is to include the fish and wildlife program in the

[5] Hydroelectric generation in the Pacific Northwest averages about 16,000 average megawatts and annual demand is about 21,000 average megawatts.

[6] The development and operation of the hydroelectric system also affects flood control, irrigation, navigation, recreation, water for municipal and industrial uses, Native American cultural resources, and water quality. All of these effects must be taken into account as the relevant agencies plan and operate the system. But the Power Act has a particular focus on the relationship between fish and wildlife and electrical energy, and so that is the focus here.

power plan, developing the coordinated resource plan described throughout this power plan that accommodates the fish and wildlife requirements while meeting the changing electricity demands of the region. This is the Council's central fish and wildlife/power "integration" function under the Power Act. Thus the first part of this appendix is devoted to explaining how the power planning process and the power system add least-cost resources over time to keep the electricity supply in balance while accommodating all the changes that affect that load/resource balance, including the effects of fish and wildlife operations. This part of the appendix also briefly discusses the matter of the costs of integrating fish and power operations.

The second part of this appendix discusses future uncertainties that would affect the fish and wildlife program and the power supply. These include uncertainties and risks related to (1) possible future changes in the fish and wildlife program; (2) an evolving power system that must integrate different kinds of generating resources, which will put more stress on the hydroelectric system; (3) possible modifications in Columbia River Treaty operations; and (4) climate change effects on the amount and timing of runoff and on electricity demands that would pose problems for both fish and wildlife and power generation.

# POWER RESOURCE PLANNING THAT ACCOMMODATES THE POWER SYSTEM EFFECTS OF THE FISH AND WILDLIFE PROGRAM

This part of the appendix is devoted to explaining how the power planning process and the power system add least-cost resources over time to maintain an adequate power supply while accommodating all the changes that affect the load/resource balance, including the effects of the fish and wildlife operations.

Prior to the development of the first power plan, the Power Act directed the Council to call for recommendations and adopt the *Columbia River Basin Fish and Wildlife Program*. Prior to each five-year review of the regional power plan, the Council must first call for recommendations and amend the fish and wildlife program. Leading into the Sixth Power Plan, for example, the Council recently completed amendments to the fish and wildlife program, resulting in the *2009 Columbia River Basin Fish and Wildlife Program* (www.nwcouncil.org/fw/program).

In this first stage in the planning sequence, the Power Act requires the Council to adopt fish and wildlife program measures that will "protect, mitigate, and enhance fish and wildlife" affected by the development and operation of the basin's hydroelectric facilities, and to do so while also assuring the region an "adequate, efficient, economical, and reliable power supply." To this end the Council's fish and wildlife program contains, among other measures, mainstem flow and passage measures (such as bypass spill) that affect hydroelectric system operations. These flow and passage measures have evolved over time, differing with each new version of the program. The changing flow and passage measures alter power generation at the mainstem dams, shifting flows and generation from winter to spring and summer as reservoir storage operations have changed to benefit fish and wildlife, and reducing potential generation in spring and summer by increasing bypass spill at run-of-the-river dams to improve fish passage survival.

Each time the Council considers and adopts a revised fish and wildlife program, it must also assess how the revised program measures will affect the region's power supply, and then evaluate, albeit in a preliminary way, if it will be possible to accommodate these changes and still assure the region an adequate, efficient, economical, and reliable power supply. The power system evaluation at this stage is necessarily preliminary. This is because what will follow immediately will be a comprehensive power planning effort that will assess whether and how to adapt the power system and add resources to accommodate changing loads and resources, including the effects on power supply of the revised fish and wildlife program.

The power plan process is then the second step in the integration of fish and wildlife program measures and power system expansion under the Northwest Power Act. The Northwest Power Act describes a regional conservation and power planning process, with an element of that planning effort focused on Bonneville's obligations and its federal system resources. As described in the main text of the power plan above, the Council projects a range of electricity demand scenarios over the next 20 years, and also assesses the amount and status of current electric power resources in the region. The Council then develops a plan for adding the lowest-cost new resources to the regional system, including (as a first priority) cost-effective conservation, and evaluates how well that plan will accommodate projected demand and other effects on the region's power supply and still maintain an adequate and reliable system. The act also calls for the plan to include a forecast of the resources required to meet Bonneville's load obligations and the portion of such obligations the Council determines can be met by conservation and by various categories of generating resources.

What's important here is that the Power Act makes the just-amended fish and wildlife program one element of the power plan. Knowing the latest flow and passage operations of the fish and wildlife program is an important part of assessing the current generating capability of the hydroelectric system at different periods in the year, and the amount of hydroelectric generation available is then one contributor to knowing the total generating capability of current regional power resources. A change in hydroelectric generation due to a change in operations for fish and wildlife is conceptually similar, in terms of the Council's power planning responsibilities under the Power Act, as any other change that will or might affect the load-resource balance and thus need to be accommodated in the resource plan, including an increase in demand for electricity.

The least-cost resource plan the Council develops has to be able to accommodate these current operations, including the fish and wildlife constraints, as well as meet other regional power system needs. The Council's resource plans have emphasized, both for the region and for Bonneville, the acquisition of all cost effective conservation on an ongoing basis, and that ongoing conservation program has contributed the most to maintaining an adequate and reliable power system. The Power Act obligates Bonneville to have that ongoing conservation program and acquire other resources, if necessary, consistent with the Council's power plan to meet its contractual load obligations for electricity and "to assist in meeting the requirements of section 4(h) of this Act" -- that is, to meet the requirements of the Council's fish and wildlife program and Bonneville's corresponding obligation to protect, mitigate, and enhance fish and wildlife in a manner consistent with the Council's program and power plan.

This is not just an "energy" issue. New or revised fish and wildlife operations alter the amount of overall energy that the hydropower system can produce, but they also alter the peaking capability of the hydroelectric system in winter and reduce the flexibility of the system to follow load and balance other variable resources, which is a growing issue with the regional power system. The Sixth Power Plan is looking at regional resource needs in all these categories --

energy, capacity, and flexibility. Changes in fish and wildlife operations can affect the power system in all three categories.

## *The 2009 Fish and Wildlife Program and Current Fish Operations*

Fish and wildlife actions identified in the 2008 NOAA Fisheries FCRPS Biological Opinion have been recognized in the Council's 2009 Fish and Wildlife Program as the baseline for fish and wildlife operations in the near future. Current operations are actually a combination of flow and passage measures in the 2008 Biological Opinion and additional spill agreed to by the parties and ordered by the federal court in the Biological Opinion litigation in recent years.

The authors of the biological opinion attempted to use best available science to develop a least-harm hydroelectric project operations plan by assessing the magnitude of potential adverse effects on fish resulting from a wide range of operational scenarios. The biological effects of the operational scenarios were estimated using the NOAA Fisheries' COMPASS (Comprehensive Passage and Survival) model, designed specifically for the reaches of the Columbia and Snake rivers extending from Lower Granite Dam to Bonneville Dam.

These provisions have substantive effect with regard to the operation of the mainstem hydropower system in the Columbia and Snake rivers. The mainstem portion of the fish and wildlife program consists of two major types of actions to promote anadromous fish survival that will also affect the power supply: 1) storage reservoir operations to affect flows; and 2) bypass spill for fish passage.[7]

### Reservoir Operations

The Biological Opinion/Fish and Wildlife Program operations call for federal storage reservoirs in the United States to be at, and not below, the maximum level specified for flood control operations in early April. This has the effect of requiring system operators to keep water levels behind these dams higher in winter and early spring than they would have (in most years) for an optimum power operation. Monthly flow objectives are then provided for both the Snake and Columbia rivers during a part of the juvenile and adult salmon migration season in spring and summer (April through August) and during the spawning season for Kootenai River white sturgeon below Libby Dam. The reservoir operation in spring largely works toward project refill while otherwise passing the snowmelt runoff downstream to try to achieve the flow objectives.

The fish and wildlife operations target reservoirs for refill by end of June. The Biological Opinion then specifies federal storage reservoirs to draft, up to limits specified in the opinion, in order to augment summer flows to aid in fish survival. This operation results in higher flows over this period than would be normal under a purely power-focused operation. For more than a decade, the federal agencies have also entered into supplemental operating agreements with B.C. Hydro to release water from Canadian storage projects to benefit fish migration in the U.S. in ways that would not occur under ordinary Columbia River Treaty operations. Finally, the operating agencies also release water in late fall and early winter to support chum flow spawning

[7] The Fish and Wildlife Program contains other measures that do not affect system operations, but which do require expenditures by Bonneville, including capital costs for fish passage and the direct cost of other fish and wildlife program actions. These elements of the program are described in more detail below. *See* the Council's 2009 Fish and Wildlife Program and NOAA Fisheries' 2008 Biological Opinion.

and rearing in the lower Columbia, and control operations in the mid-Columbia River to support fall Chinook spawning and rearing in the Hanford Reach.

The main effect of this operation on the power supply is to reduce the generating capability of the hydroelectric system over the winter, at the time of the region's peak loads, and to increase generation when runoff is passed through in the spring and when it is released from storage in the summer, generally producing surplus generation over native regional demand. There is not a one-to-one shift in energy production from winter to spring/summer because of bypass spill requirements.

### Bypass Spill

Bypass spill is the re-routing of river flows away from turbine intakes and into fish passage and spillway systems. The survival of migrating juveniles diverted into fish passage systems and over spillways is considerably higher than fish survival rates through the turbines although not always higher than fish that are transported. The Fish and Wildlife Program and NOAA Fisheries Biological Opinion call for the eight federal dams on the lower Snake and Columbia rivers to divert part of their flows through fish bypass systems during spring and summer. As noted above, additional spill has occurred in recent year as a result of a court-approved agreement among the parties to the Biological Opinion litigation. It is not clear whether such additional bypass spill will be required in future years, therefore it was not assumed in the analysis.

Hydropower generation is reduced from what it would be without bypass spill, which is provided in spring and summer months. Bypass spill can affect the firm generating capability of the hydroelectric system, but in most years it translates into a loss of non-firm or surplus power available for sale on wholesale power markets. Surplus power sales are made to serve peak loads or to displace more expensive resources for both Northwest and Southwest utilities. The main effect of surplus sales for Bonneville is to generate revenue that helps to cover the cost of its operation of the federal hydropower system, reducing its debt to the Treasury, and covering other costs, including those for fish and wildlife. Under certain conditions, spill can also reduce reactive support for the transmission system, which leads to reduced transmission capability and could potentially reduce system reliability.[8]

The Biological Opinion/Fish and Wildlife Program specify additional operational limitations, including turbine operating criteria and limits on how fast flows may be ramped up or down through changes in project discharge levels. These constraints have little effect on the total energy production of the system, but instead reduce the system's flexibility to follow load and accommodate varying wind output. These effects are difficult to model or estimate quantitatively, but are real nonetheless.

## *Modeling the Power System*

As part of the power plan effort, the Council has to estimate the current generating capability of the hydroelectric system. Operations for fish and wildlife are only part of this effort, and must

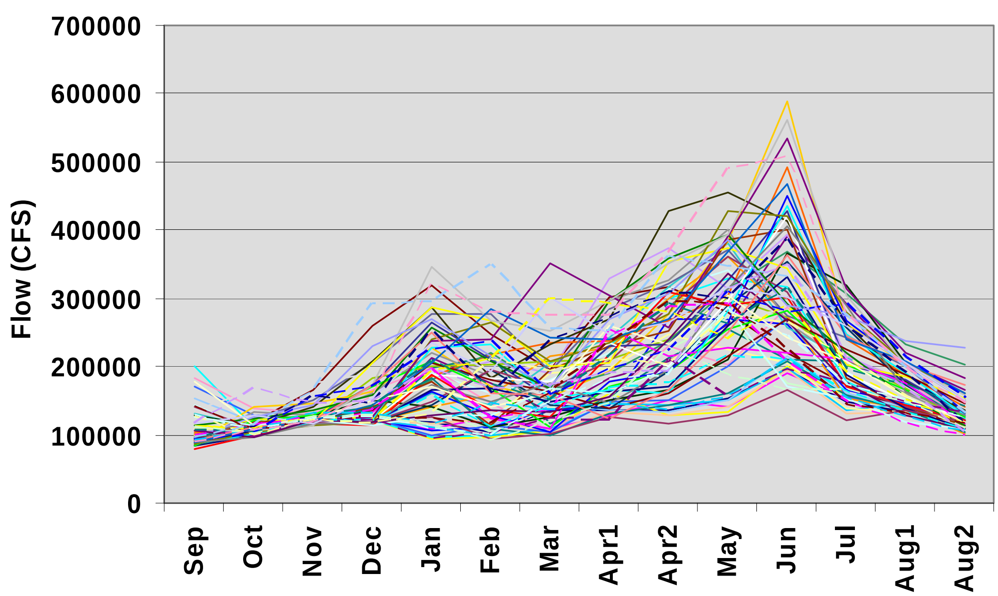
[8] See the Memorandum dated February 24, 1998, memorandum from John Fazio to the Council regarding the transmission impacts of drawing down John Day Reservoir and other fish and wildlife operations (Council document 98-3).

be combined with the runoff pattern (both amount and shape), with operational requirements and constraints for purpose of flood control (which are significant) and navigation, irrigation and other non-power purposes (relatively minor on overall system operations), and power system objectives (i.e., load objectives). The end result is a series of monthly reservoir elevation and flow profiles, and then, especially, monthly generation patterns (bi-monthly in April and August). The modeling effort can be done on a planning basis, using different runoff patterns representing the 70-year historical water record (and the Council and Bonneville both do this), or on an "actual" basis, looking at a past year's actual runoff and generation (Bonneville does this).

The analysis of system operation and hydroelectric generation is performed with the GENESYS model.[9] The model simulates the operation of regional resources including hydroelectric facilities over many different future conditions. For the hydroelectric system, key outputs include regulated outflows, reservoir elevations, and generation. (Another output is cost, but that is addressed in the second part of the appendix.) GENESYS simulates both a monthly and hourly dispatch of available resources to meet regional load. In the monthly mode, it simulates the operation of individual hydroelectric facilities. In the hourly mode, however, the hydroelectric system is operated in aggregate and the peaking capability of that system is approximated using linear programming techniques.

This model is designed to address both energy (monthly and annual) needs and capacity (hourly) needs. The results depicted below are based on the use of GENESYS to analyze the operations outlined in the Council's Fish and Wildlife Program, consistent with those in NOAA Fisheries' 2008 Biological Opinion. Figures M-1 and M-2 show the range of outflows at Lower Granite and The Dalles dams for each of the 70 water conditions modeled. Figure M-3 shows the range of system generation in average megawatts by month and Figures M-4 through M-7 show the range of elevations by month at Libby, Hungry Horse, Grand Coulee and Dworshak dams.

**Figure M-1: Flow at The Dalles**




[9] See http://www.nwcouncil.org/genesys.

**Figure M-2: Flow at Lower Granite**

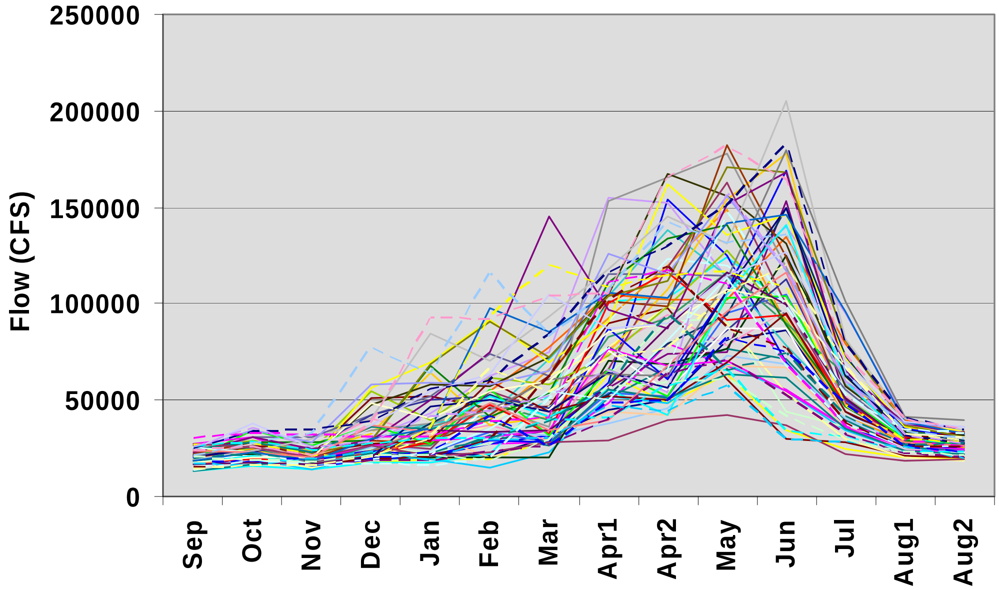



**Figure M-3: Hydroelectric Generation**

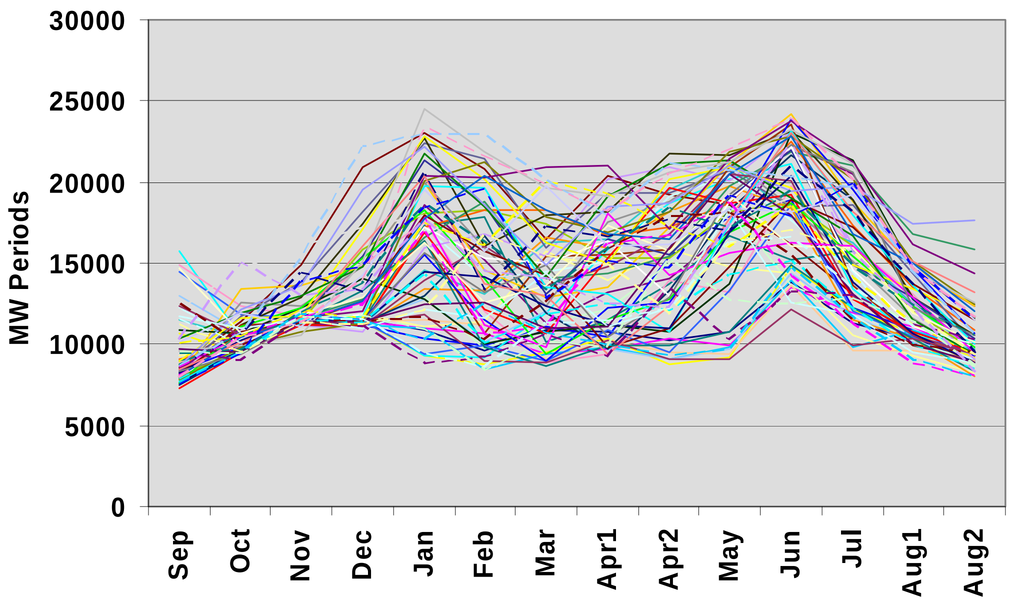


**Figure M-4: Elevation at Libby Dam**

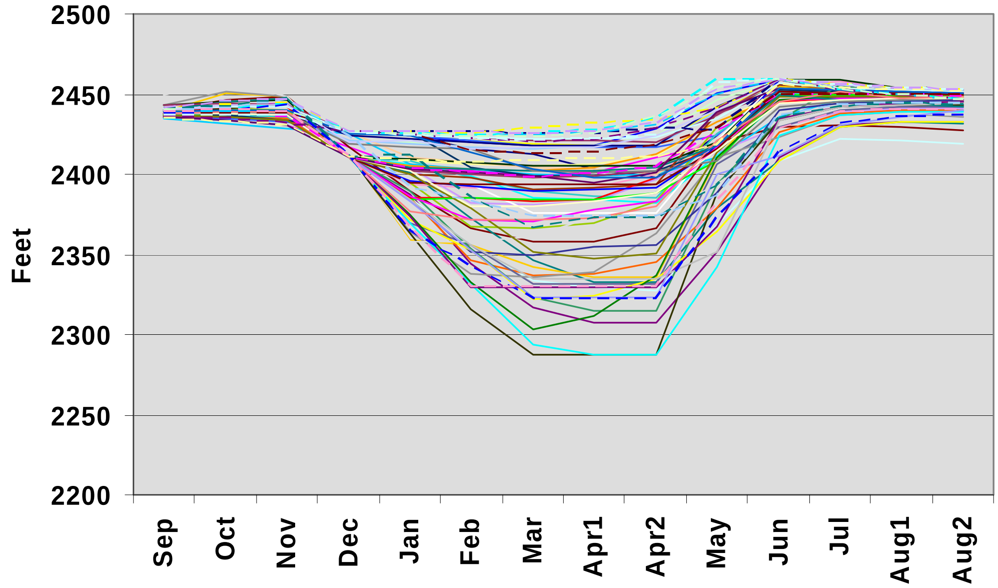



**Figure M-5: Elevation at Hungry Horse Dam**

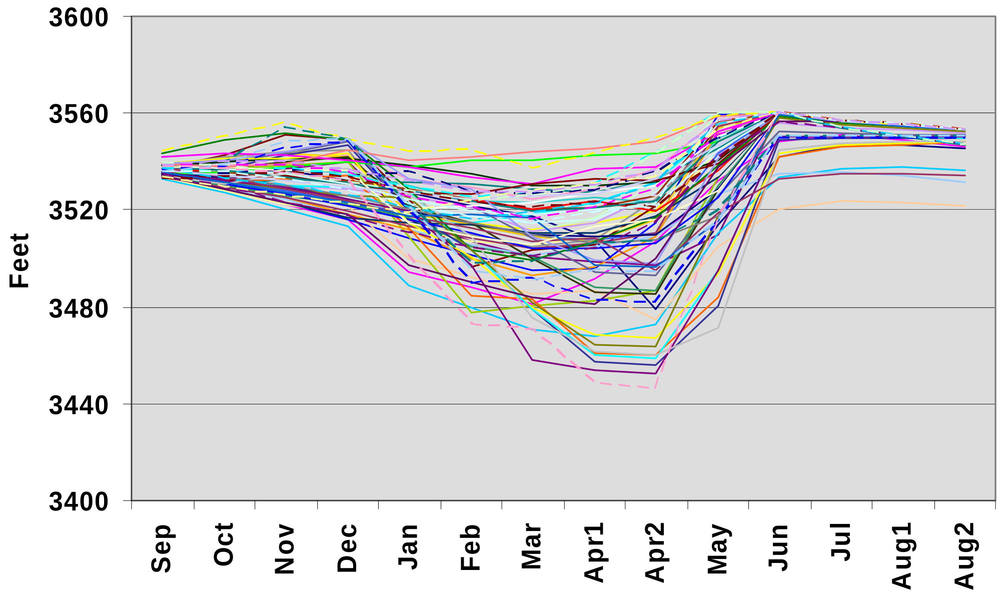


**Figure M-6:  Elevation at Grand Coulee Dam**

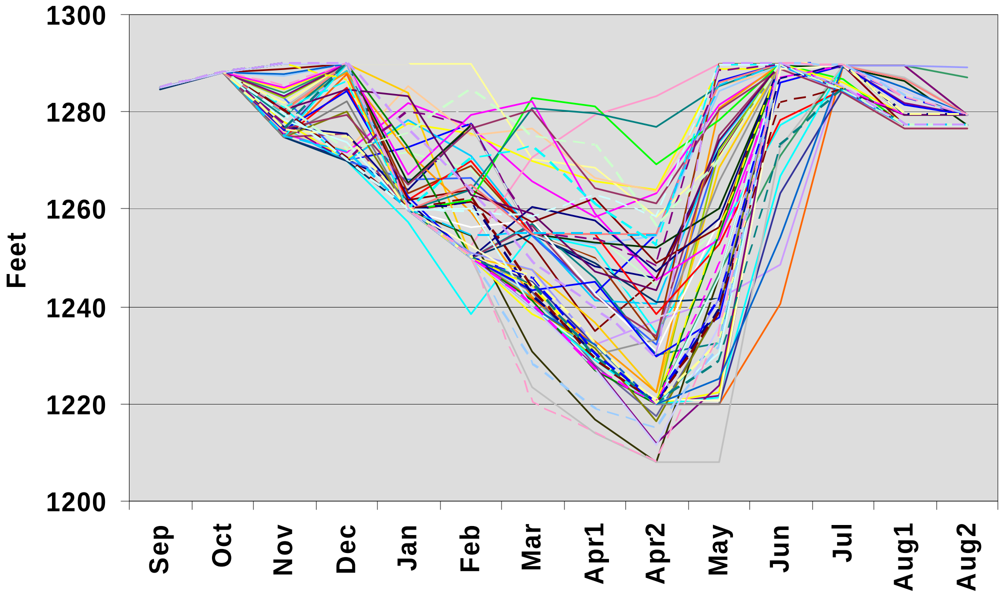
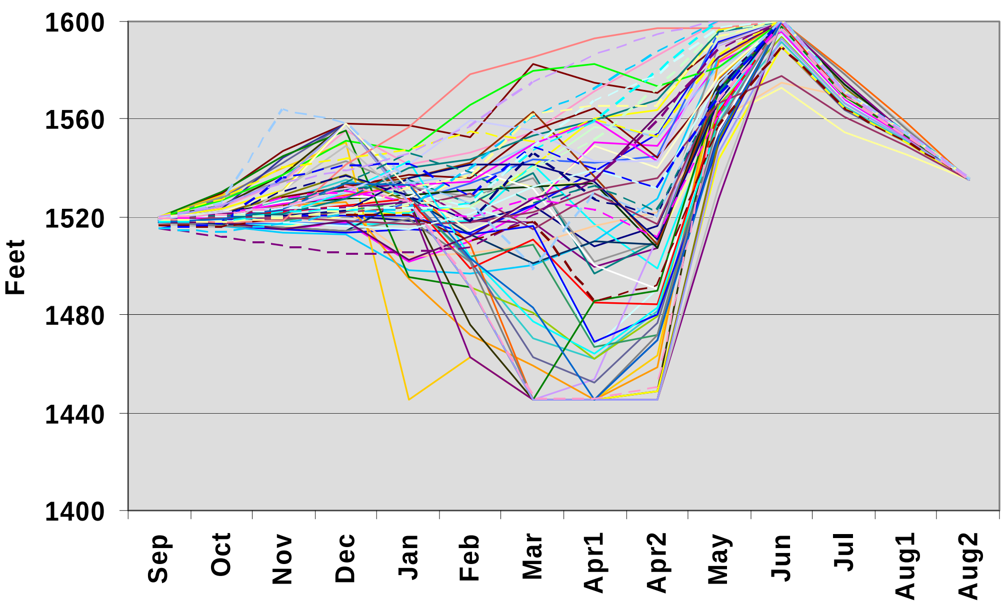



**Figure M-7:  Elevation at Dworshak Dam**




For current resource planning purposes, of course, the more important information is the change in the firm power generating capability since the last iterations of the Fish and Wildlife Program (2003 Mainstem Amendments/2000 FCRPS Biological Opinion) and Power Plan (Fifth Power Plan, December 2004).  We did not begin shifting flows and thus generation from winter to spring/summer just recently -- the fish and wildlife program was built to current levels from the original water budget in 1982, with major evolutions ever since.  And resource planning and resource acquisitions have accommodated these changes in hydroelectric power production and peak capacity.  Although the overall loss of generation attributed to operations for fish are significant, the recent additions to that loss are relatively small. For example, the annual average incremental loss of hydroelectric generation since 2005 due to fish operations is on the order of 20 average megawatts.

For an historical perspective, however, it is important to note total changes in hydroelectric operations since before fish and wildlife measures were first adopted. This information is not important for resource planning or for fish and wildlife decision making, but it is useful for understanding the full magnitude of changes over time. The following charts display these differences.

**Figure M-8: Average Outflow at The Dalles Dam**

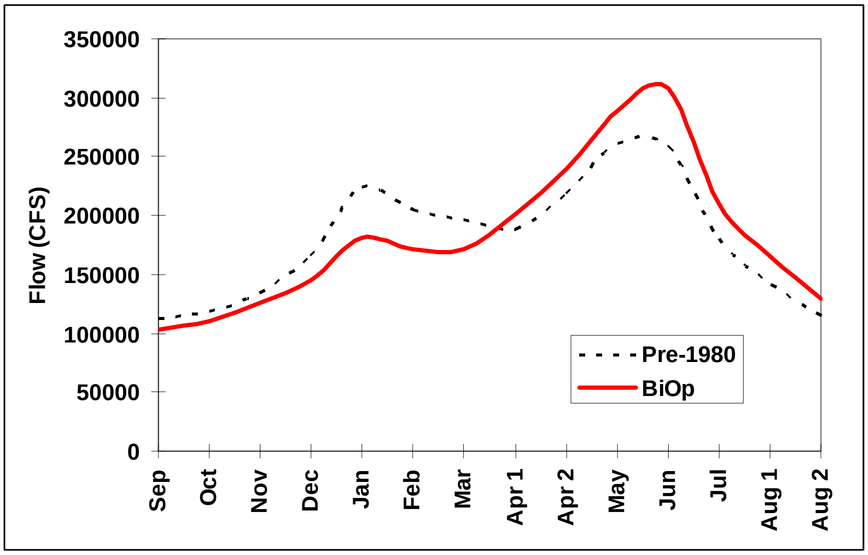
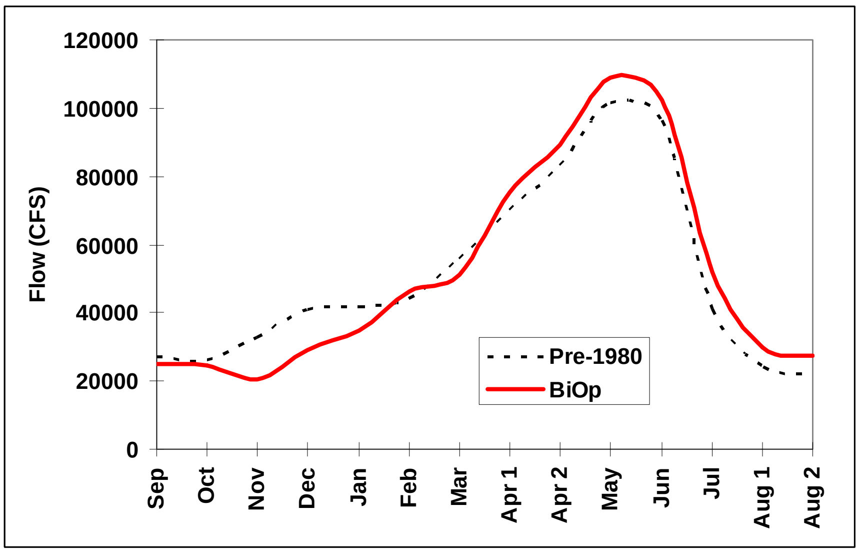



**Figure M-9: Average Outflow at Lower Granite Dam**




In order to reshape river flows, water in reservoirs that would have been used for power production during winter months is kept in storage for later release during spring and summer. The following four charts (Figures M-10 to M-13) show the average reservoir content for Libby, Hungry Horse, Grand Coulee and Dworshak dams, in units of thousands of second-foot days or

KSFD (one KSFD is equal to about 2000 acre feet or 2 KAF). The pattern of keeping more water in these reservoirs during winter months is clearly apparent in these charts. Additional water is also released at these projects over the summer months, which leaves these reservoirs at lower elevations by the end of August or September. On average, Dworshak reservoir is 80 feet below full, Libby and Hungry Horse are 10 to 20 feet lower and Grand Coulee is between 10 and 12 feet lower by summer's end.

**Figure M-10: Average Reservoir Content at Libby Dam**

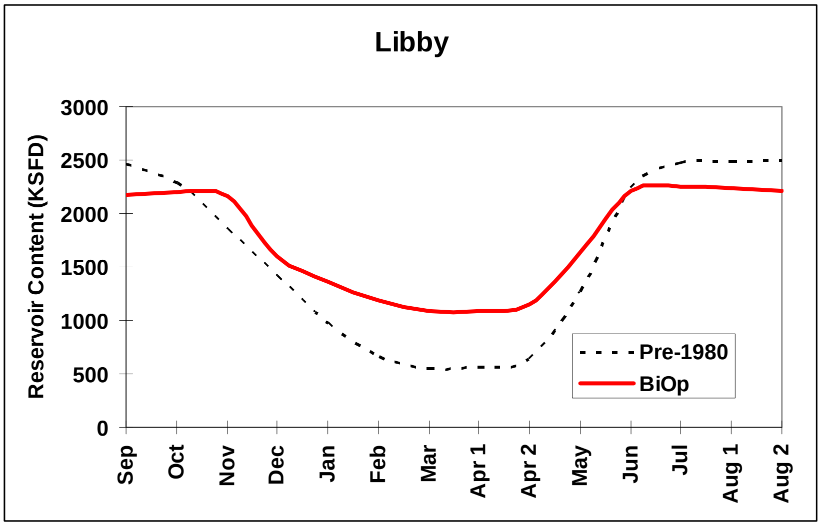



**Figure M-11: Average Reservoir Content at Hungry Horse Dam**

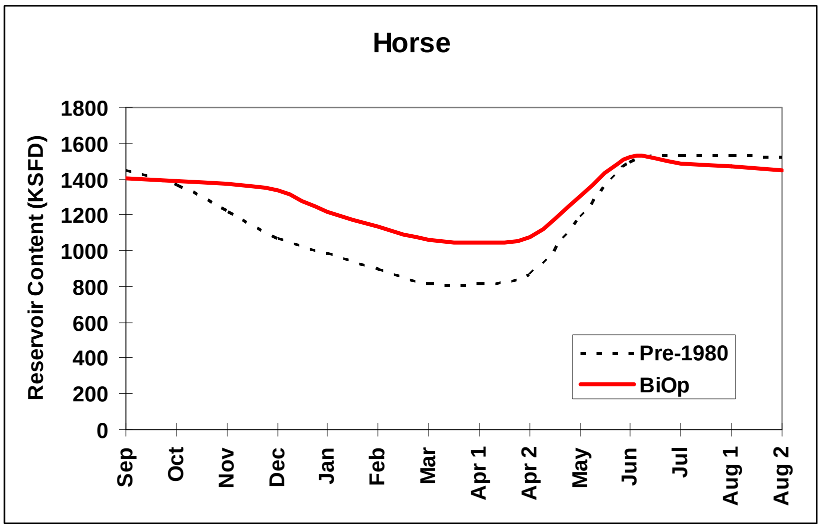


**Figure M-12: Average Reservoir Content at Grand Coulee Dam**

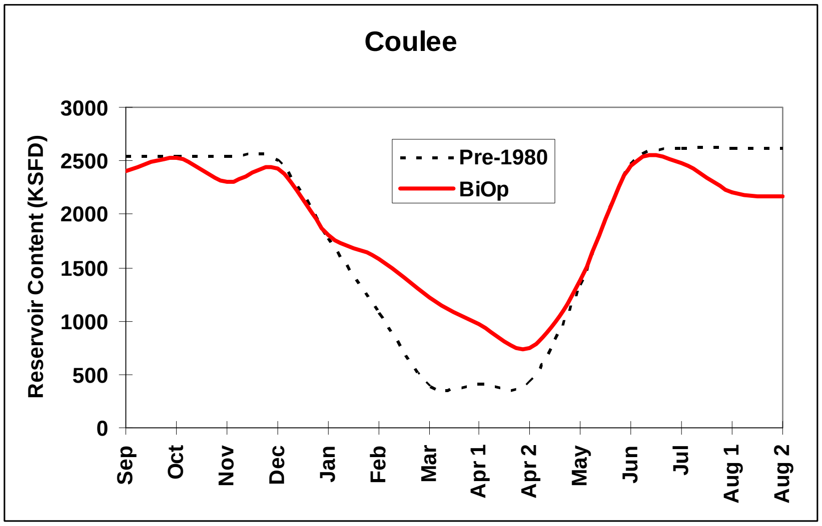
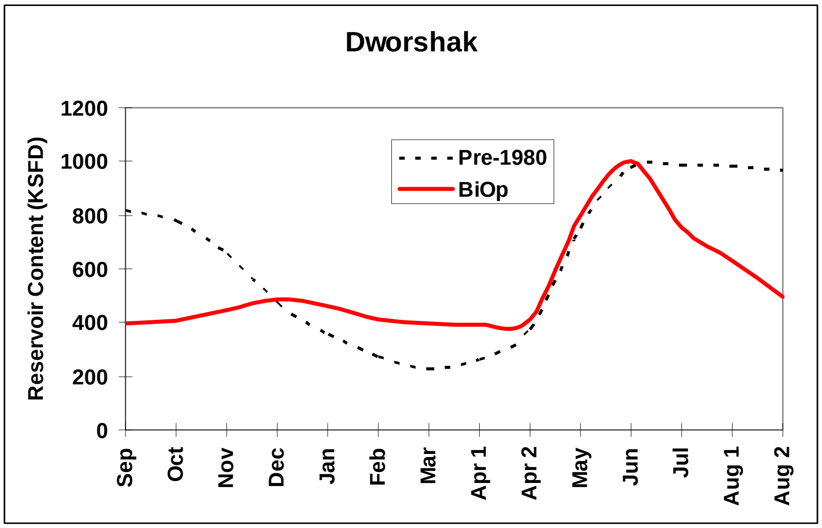


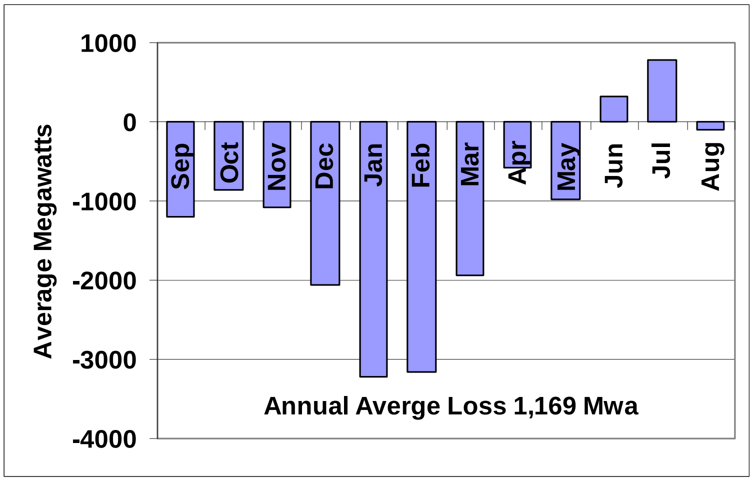

**Figure M-13: Average Reservoir Content at Dworshak Dam**




Council analysis indicates that, on average, implementation of the program will reduce hydroelectric generation by about 1,200 average megawatts relative to an operation without any constraints for fish and wildlife. For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability.[10] Figure M-14 below shows the monthly average change in hydroelectric generation between current operations and a pre-1980 operation, which includes no fish and wildlife constraints.

[10] Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.

**Figure M-14: Change in Monthly Average Hydroelectric Generation since 1980**




## *Resource Planning*

As described above, the central purpose of the power plan is to assess the current and projected demand for electricity for the next 20 years and current resources and then develop a plan for acquiring all cost-effective conservation and, if necessary, generating resources to add to that system in order to maintain an adequate and reliable power supply in the Pacific Northwest at the least cost and least risk. Accommodating the effects of the fish and wildlife program is just one part of that resource analysis. The relevant resource analysis and the plan to add resources are described in the main chapters of the Power Plan and in the Action Plan.

## *Providing an Adequate Operation for Power and Fish*

Bonneville and the other federal operating agencies implement the fish and wildlife operations, and the rest of the Fish and Wildlife Program, consistent with the Northwest Power Act, the federal Endangered Species Act, the project authorizations, and other applicable law. The hydroelectric operations to improve fish survival that are specified in the Council's Fish and Wildlife Program also become a part of the power plan. The power plan must be designed to provide both an adequate and reliable power supply and allow for effective implementation of the fish and wildlife operations as part of the program to protect, mitigate, and enhance fish and wildlife resources. The impacts of those fish and wildlife operations are substantial and would definitely affect the adequacy and reliability of the power system, if implemented over a short period of time. However, this has not been the case. As described above, since 1980, the region has periodically amended fish and wildlife-related hydroelectric operations and in each case, the power system has had time to adapt to these incremental changes and has maintained an adequate and reliable power supply.

The Council staff produced a preliminary assessment of the impacts of fish operations on the adequacy and reliability of the power supply during the recent fish and wildlife program amendment process. A more detailed adequacy and reliability assessment is provided in this power plan. That assessment (Chapter 14) indicates that the regional power supply can reliably provide the actions specified to benefit fish and wildlife (and absorb their cost), respond to other challenges to the reliability and adequacy of the regional system described in that chapter, and maintain an adequate, efficient, economic, and reliable energy supply. The assessment indicates that in order to accomplish this task, the region must acquire new resources and conservation over the study horizon period (also see Chapters 9 and 10). Moving forward, the Council's resource adequacy standard provides a minimum threshold for resource development that keeps the likelihood of curtailments to both power and fish operations within acceptable levels.

In addition to the adequacy standard, power planners have become more cognizant of non-emergency situations, such as isolated low flow events, night-time over-generation conditions, and rapid load changes that have compromised fish operations in the past. Planners are actively developing operational protocols to address these situations and to alleviate the pressure to curtail fish operations. For example, the U.S. Army Corps of Engineers (Corps) describes how it intends to deal with these situations in its planned operations for fish passage for 2009 (Corps document number 1693-2, "2009 Spring Fish Operations Plan").

In spite of best laid plans, however, emergencies sometimes occur, and all utilities have contingency actions in place to avoid potential curtailments. We do not and cannot plan and build for 100% assurance of power system operations, nor the same for the operations specified for fish. What we can do is reduce the likelihood of emergencies to an acceptable level (mostly through adding sufficient resources to the system), and then have contingency plans in place to deal appropriately with power and fish emergencies.

Hydro flexibility is one method for dealing with power system emergencies. During periods of rapid load changes or the loss of a major resource or transmission line, reservoirs can be drafted below their normal operating elevations to sustain electricity service. This use of additional hydroelectric generation is often referred to as "hydro flexibility." Hydro flexibility is generally used during cold snaps or heat waves when no other resources are available, including imports from out of region. The additional water drafted to produce extra energy is replaced as soon as possible, even if energy must be imported. Most often reservoirs can recover and get back to required refill elevations. However, in the event that hydro flexibility can not be replaced by early spring, less water would be available for the spring flow operation for fish and wildlife augmentation. The power plan, resource additions, and in-season planning strategies should be designed to reduce the likelihood of situations in which hydro flexibility cannot be replaced prior to the migration season.

Both bypass spill requirements and reduced mainstem reservoir operating limits imposed by the program limit the flexibility of the hydroelectric system. This is important because less flexibility means a reduced ability to meet peaking requirements, provide ancillary services, and integrate wind and other variable resources. Once system flexibility is used up, additional resources may need to be added along with variable generators to provide a reliable supply. This will clearly increase the cost of meeting renewable portfolio standards and may also increase carbon emissions. As discussed in Chapter 12, creative strategies for operating the system to balance renewable resources, and then careful planning to add least-cost resources to meet the system's capacity and flexibility requirements are key to preserving reliable implementation of fish and wildlife operations while maintaining power system reliability.

The FCRPS Biological Opinion allows for curtailment of fish and wildlife operations during power system emergencies, as happened in the very low water year of 2001, but it does not specify an upper bound for such actions. It also includes comparable language that allows deviations from normal power system operations during rare occasions when emergency fish passage conditions occur.

Whenever the region's generating capability lags behind demand growth (as happened in the late 1990s), the risk of having to curtail fish and wildlife operations will increase. Using curtailment of fish and wildlife operations as a last-resort alternative during rare emergencies is allowed under the Biological Opinion language[11]. The key word in the previous sentence is "rare." Analysis showing a high frequency of curtailment to fish and wildlife operations would indicate that the power supply is not adequate. Curtailment of fish and wildlife operations cannot be used in lieu of acquiring resources to maintain an adequate regional power supply. In the same way, power system operations should not be jeopardized an inordinate amount to deal with fish emergencies.[12]

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 these policies in place prior to an emergency, in order to minimize the risk to fish. Action item F&W-2 (see the Action Plan) calls for the Council to work with fish and wildlife managers and regional power planners to review existing contingency plans to ensure that they are consistent with the fish and wildlife program and the power plan.

# DEALING WITH AN UNCERTAIN FUTURE

Adequately integrating the needs of fish and wildlife and the region's power consumers is a difficult task even when all relevant parameters are known. However, the future will undoubtedly present a number of uncertainties that will continue to challenge planners in their attempts to provide for all river users. These include the uncertainties and risks related to (1) possible further changes in the operations to benefit fish and wildlife; (2) an evolving power system, which must integrate variable output resources (such as wind) that put new and different requirements on the hydropower system; (3) possible modifications in Columbia River Treaty operations over the next decade, for both power and non-power reasons; and (4) climate change effects that are likely to change the amount and shape of runoff and regional electricity demands. This part of the appendix addresses these future uncertainties and their associated risks.

The power plan has a 20-year planning horizon, which requires that potential future changes in the hydroelectric system or for fish and wildlife needs over that time period must be assessed. The resource strategy developed in this power plan must be sufficiently robust to accommodate these potential changes in order to continue to provide benefits for fish and wildlife and an adequate and reliable power supply. The challenge is to identify the uncertain but possible areas of change, assess the possible range of effects and develop a set of actions to accommodate these changes. This implies that the power plan must be flexible and dynamic so that it can deal with uncertainties if and when they occur.

Likely categories for significant change include modifications in operations for fish, reduction in hydroelectric system flexibility due to increasing amounts of variable resources, possible changes in the Columbia River Treaty, climate change, and potential bypass spill reductions associated with spillway weirs.

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[11] This refers to Reasonable and Prudent Action item 8 in NOAA Fisheries' 2008 FCRPS Biological Opinion.
[12] This refers to Reasonable and Prudent Action item 9 in NOAA Fisheries' 2008 FCRPS Biological Opinion.

The Council along with other regional entities, including the Independent Economic Analysis Board[13] recently examined the interactions between fish and power operations and identified several important factors to be considered in the development of this plan:

- In the long term, hydroelectric generation could increase due to installation of spillway weirs at federal dams. Spillway weirs are designed to increase juvenile migrant passage survival while reducing the volume of bypass spill. However, the Council assumed no long-term increase in hydroelectric generation due to spillway weirs.

- There remains a great deal of uncertainty regarding the amount of future bypass spill. It is possible that long-term hydroelectric generation will change due to adaptive management or litigation. However, quantifying this potential change is difficult. The Council's resource strategy analysis does not include changes in bypass spill as an uncertainty. It assumes that bypass spill levels are fixed, as specified in the 2008 Biological Opinion. Additional court-ordered spill, which has been implemented since 2005, is not included in the analysis because it is uncertain whether it will be incorporated into long-term Biological Opinion operations. The additional spill essentially requires dams to spill up to their maximum allowable dissolved gas levels (e.g., within the states' Clean Water Act standards). On an annual basis, court-ordered spill reduces hydroelectric generation by an average of about 150 average megawatts, relative to about a 1,200 average megawatt loss for the 2008 Biological Opinion mainstem operation. However, bypass spill is only provided in spring and summer. Looking at the additional loss seasonally, court-ordered spill decreases generation by an average of about 200 average megawatts during spring (April through June) and by an average of a little under 600 average megawatts during summer (July and August). The losses in any given year, obviously, will vary depending on water conditions.

- Mainstem operations for fish and wildlife tend to reduce the hydroelectric system's flexibility and increase the cost of integrating wind resources. Flexibility of electricity supplies is vital to ensuring a reliable power system. Efforts are underway to quantify this loss of flexibility. Some, but not all, of the effects of this loss of flexibility were captured in the Council's analysis for the plan. However, the Council recommends continued regional participation in discussions and analysis of this issue.

- New water management strategies or development of new storage facilities would clearly affect hydroelectric generation in the long term. However, given the long lead time required to develop and implement these projects, it is not likely to happen in the short term, if at all. Thus the Council assumes that no new water management strategies or storage facilities will be implemented for the power plan analysis.

- Terrestrial and wetland habitat protection and restoration funded by the fish and wildlife program may create opportunities to develop carbon credits. Discussions of potential benefits to the power system are just barely underway. No assumptions regarding potential future carbon credits for habitat development were included in the plan.

Other potential long-term changes may include additional or different operations for fish such as:

[13] See the IEAB report at http://www.nwcouncil.org/library/ieab/ieab2009-1.htm

- Lower operating elevations during the migration season (e.g., John Day Dam at minimum operating pool elevation instead of minimum irrigation pool elevation);
- Changes in the volumes of water for flow augmentation;
- Different pattern of water releases during the migration season;
- Removal of one or more mainstem federal dams;
- Revised Columbia River Treaty operations;
- Revised use of non-treaty storage; and
- Changes to flood control operations

The potential effects of climate change show impacts to both power and fish. Current analysis indicates that the Northwest is likely to see higher winter river flows and lower summer flows, with peak flows shifting to earlier periods in the spring. At the same time, winter demand for electricity should decrease and summer demand would increase with rising temperatures. This effect should ease the pressure on the hydroelectric system in winter but make it more difficult over summer months, especially with the addition of more and more variable resources. Therefore, climate change may increase pressure on the power system in the summer by increasing loads and reducing hydropower generation and at the same time adversely affect fish because of higher water temperatures. A summary of the Council's analysis of potential physical climate change impacts is presented in Appendix L.

Current renewable portfolio standards have already affected resource acquisition strategies and will likely continue to do so if they are modified or replaced by federal legislation. Potential carbon tax or cap-and-trade mechanisms will also alter future resource plans.

Ongoing changes in power markets and westwide power integration may also bring changes to the way we use and value the power system (e.g. generation in summer may become more and more profitable). These kinds of changes present challenges for fish and wildlife operations. For example, releasing more stored water during summer months may increase power revenues and provide higher river flows for migrating smolts, but may also adversely affect resident fish above and below the federal projects.

For this plan, long-term uncertainties already include load, fuel and electricity prices, runoff conditions and carbon penalties. Uncertainties not explicitly incorporated into resource plan development include the physical effects of climate change, modifications to fish operations or changes in the Columbia River Treaty. Because of difficulties in quantifying the range and magnitude of these latter uncertainties, it is best to assess these by means of sensitivity analysis. Studies can be performed to determine the potential effects of these changes, either independently or in combination. However, the magnitude of potential impacts must be considered in conjunction with the likelihood of occurrence, that is, a potential uncertainty may have a large impact but might be extremely unlikely. The region should continue to explore and analyze such scenarios to be better prepared should these unlikely events occur.

While there is much the Council can do as part of both the fish and wildlife program and the power planning process to analyze and respond to these long-term considerations, regional cooperation is also needed. Federal agencies have already formed several committees to deal with in-season operational issues affecting fish and power. For example, the Technical Management Team (TMT) consists of technical staff from federal, state, and tribal agencies that usually meet on a weekly basis during the fish migration seasons 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 Regional Implementation Oversight Group (RIOG), which consists of higher policy-level staff.

While the existing committee structure is intended to solve in-season problems, no currently active process exists to address long-term planning issues related to both power planning and fish and wildlife operations. The Council will investigate using existing forums to facilitate such discussions or, if necessary, explore the possibility of creating a separate forum where fish and wildlife managers and power planners could jointly explore longer-term strategies to improve both fish and wildlife benefits and hydroelectric power operations. In such a forum, synergistic effects between fish and wildlife operations and power planning could be examined. For example, conservation savings in irrigation can also provide savings in water quantity and energy, which could benefit both in-stream flows for fish and reduce load on the power system. Also, the State of Washington is currently exploring options for new storage sites, which could benefit fish, power and irrigation. And finally, potential carbon emission mitigation benefits of actions to acquire or improve fish and wildlife habitat should be assessed.

Action Plan items F&W-1 (long-term planning forum); F&W-3 (analytical capability), F&W-4 (Columbia River Treaty), and F&W-5 (climate change) are intended to help the Council and the region to develop the tools needed to address these uncertainties.

# Appendix N: Financial Assumptions and Discount Rate

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## INTRODUCTION AND SUMMARY

The Council uses a real discount rate of five percent for its analysis for the upcoming power plan. This is based on mid-term forecasts of the cost of capital to the entities or sectors examined. The sections below briefly review the need for a discount rate, the various approaches that have been taken in the literature and relied upon by the Council in the past, and the development of the specific values that are suggested to be used. The appendix also notes that, unlike other data in the power plan, which can be used directly by the various regional entities responsible for meeting loads, the discount rate used in the Council's analysis is a composite rate that will not be directly applicable to most of these entities making resource decisions. The approach to calculation of a discount rate is applicable, however.

The underlying financial assumptions were updated in October 2009, based on the most-recent Global Insight long-term forecast.

## BACKGROUND

Investment analysis, such as that for the Council's plan, typically has to compare projects with different time patterns of costs. A conservation project or a wind turbine installation, for example, is characterized by high fixed investment costs and low operating expenses. With initial capital costs repaid over time, the time pattern of costs for this type of investment will typically look generally flat over its lifetime. Contrast this with, for example, a combustion turbine investment, where the bulk of the cost is in the fuel rather than the fixed cost. With any escalation in real terms – above the general level of inflation – the biggest part of the lifetime cost will come in future years.

The discount rate is a fundamental piece of the Council's resource analysis for the power plan. The discount rate is the piece that tells us the rate of time preference we are applying to the analysis, that is, how much relative importance we give to costs and benefits in different years in the future. The discount rate is used to convert future costs or benefits to their present value. A higher discount rate reduces the importance of future effects more than a lower discount rate. All else equal, a higher discount rate would tend to value a combustion turbine over a wind project, for example, by disproportionately reducing the higher fuel costs in future years. On the other hand, a low discount rate would not reduce the effects of those future costs so much. A discount rate of 0 percent for example, would treat effects in all years, whether next year or 30 years from now, the same in terms of their impact on the investment decision taken now.

This notion of time preference is not, however, an abstract preference for the short term versus the long term. Time preference is directly tied to the concept of a market interest rate. Putting aside questions of risk temporarily, a dollar to be paid next year is less of a burden than a dollar this year. That is because one could invest less than a dollar today and, assuming sufficient return on that investment, use the proceeds to pay the dollar cost next year.

From the other side, a dollar benefit this year is more valuable than the same dollar benefit next year, because it can be turned into more than a dollar next year by investing it. The important point here is that dollars at different times in the future are not directly comparable values; they are apples and oranges. Applying a discount rate turns costs and benefits in different years into comparable values. Because the Council's analysis looks at annual cost streams of various resource types, discounting is required in order to calculate and fairly compare total costs of alternative policies.

Market interest rates embody the effect of everybody's rates of time preference. Individuals and businesses that value current consumption more than future consumption will tend to borrow, and those that value future consumption more will save. The net effect of this supply and demand for money is a major factor in setting the level of interest rates, as are the actions of the Federal Reserve in setting the federal funds rate and influencing inflation expectations through its actions on the aggregate money supply. Market interest rates also embody considerations of uncertainty of repayment, inflation uncertainty, tax status, and liquidity, which together account for most of the variations among observed interest rates.

Because of this overall relationship between rates of time preference and interest rates, the level of the discount rate should be related to the level of interest rates. The difficulty is in determining which interest rate is the appropriate one for the choices being made. There are three general approaches in the literature that can be used for this choice, which can be described as the regional consumer's perspective, the corporate perspective and the national perspective.

Finally, risk and uncertainty in capital project evaluation is sometimes treated by modifying the discount rate and sometimes by directly modifying the treatment of costs and benefits in the analysis. There are theoretical arguments in the economic literature on all sides of these issues. The Council's analysis evaluates project risk and uncertainty explicitly and does not incorporate it into the discount rate decision.

## *Regional Consumer's Perspective*

The regional consumer's perspective looks at the after-income tax returns available to regional consumers to determine their rate of time preference. This perspective bypasses considerations of who, or what kind of entity, is making the investment decision and addresses the question for whom the investment is ultimately being made, regional utility customers in this case. The Council had taken this perspective in earlier plans and had examined a number of different kinds of interest rates that individuals earn or have to pay, ranging from savings accounts with negative real after-tax returns, through mortgages and stock and bond market returns, to the cost of credit card interest, which is quite high in real, after-tax terms. Generally, the Council had concluded that mortgages and stock and bond investments best represented the household consumer's rate of time preference.

## *Corporate Perspective*

The corporate perspective addresses the perspective of who, or what kind of entity, is making the investment decision. It typically looks at a company's weighted cost of capital, adjusted for the deductibility of bond interest from corporate income taxes to the company, as the starting point for choosing a discount rate to evaluate investment decisions. With this approach, we would use a cost of capital roughly weighted by the types of financial entities represented by the utilities in the region (municipally financed, treasury financed, taxable-market financed and equity financed).

The literature on corporate investment decisions almost uniformly holds that the correct discount rate is the firm's tax-adjusted cost of capital. Broadly considered, this perspective uses the cost of capital to the entity making the investment decision. While most of the literature focuses on private corporate entities, this perspective is also applicable to entities with other forms of ownership, as long as they are externally financed. Using the corporate cost of capital as the discount rate will ensure that the decisions that are made maximize the value to the owners of the firm. This argument would also apply to publicly owned entities without stockholders.

There is a second argument in favor of this perspective that would also apply for those entities without stockholders or for those which have a focus on something other than owner wealth maximization. This argument holds that the majority of the investment decisions in the U.S. are made by private corporations that use this investment rule. To use another rule for a limited sector of the economy would distort investment patterns in the overall economy, either over-investing or under-investing, depending on whether the discount rate is lower or higher than appropriate.

This is the perspective that has been adopted (implicitly or explicitly) by the region's IOUs and the utility commissions who regulate them. With this perspective, Bonneville would use its cost of capital – treasury borrowing plus a markup – and the region's publicly owned utilities would use theirs – tax-exempt municipal bond borrowing. The Council uses the corporate perspective in preparing forecasts of future generating resource development and power prices, under the assumption that on-the-ground resource development decisions will be based on corporate discount rates.

## *National or Social Perspective*

There is a third perspective, which might be called the "national consumer's" or the "social" perspective. This is similar to the regional consumer's perspective except that it looks at pre-tax returns/costs rather than after-tax returns/costs. From an overall social perspective, income taxes are a deliberately incurred device that, among other things, raises the cost of capital to individuals and most corporate entities[1]. This is sometimes combined with the corporate

[1] This effect is partially mitigated by the reduction in income taxes afforded by the deductibility of interest payments mentioned above.

perspective in arguments that national government investments should adopt some form of the private sector's cost of capital as the discount rate, using, however, the pre-tax rather than the tax-adjusted cost (as the firm itself would use).

### *Risk and Uncertainty Issues*

As mentioned earlier, variations in risk and uncertainty account for a major part of the differences among returns to various potential investments. It is important to try to capture these elements of potential investments in the analysis in some manner, and at the same time, not double count them by embodying them in both the discount rate and the rest of the analysis. The Council's resource analysis explicitly accounts for major uncertainties and risks, such as water conditions, load growth uncertainty, fuel prices, power market prices, CO2 mitigation requirements, and so forth.

## APPROACH CHOSEN

In the Fifth Power Plan, the Council adopted the corporate perspective in setting the discount rate. The Council continued to use the corporate perspective in adopting a discount rate for use in the Sixth Power Plan. This approach is most frequently recommended in the economic literature and is widely used in the electric industry, as well as in other industries. It leads to a discount rate that aligns the decision about investing capital with the interest rates and cost of that capital to the entity making the investment decision.

For the Sixth Plan, this approach has been modified to include the effect of other investment decision makers, end-use consumers, as appropriate for the decision in question, rather than implicitly assuming that all decisions on resources are made by utilities. This will be described further below.

It should be noted that, unlike much of the analysis and data provided by the Council in its plans, which are directly useable by the entities acquiring resources, costs of capital and discount rates derived from them are specific to each entity. A composite rate, such as the Council uses, will not likely be appropriate for use by any particular utility, though the Council's approach to choosing a value should be useful and is recommended.

## CONSIDERATIONS IN CHOOSING A SPECIFIC VALUE FOR THE COUNCIL'S PLAN

The plan will be completed in late 2009, and the period over which it will be most relevant for decision making will be the succeeding five years, starting in 2010. Consequently, the analysis looks primarily at forecast data for 2010 - 2014.

The approach in this appendix builds on two sets of assumptions. The first is the relative shares of future investment decisions made by different actors (BPA, publicly owned utilities, IOUs and residential and business customers). The second is a set of forecast data developed by Global Insight, a national economic consulting firm, whose forecasts are used for various purposes by the Council.

The first set of assumptions looks at decision makers. Because the chosen approach looks at investment decision makers, and because a significant fraction of the conservation resource is expected to be paid for directly by consumers, we have made assumptions about the shares of the ultimate portfolio that will be made up of generation and conservation and the shares of the conservation decisions that will be made by consumers. Generation decisions will be made by utilities; conservation investment decisions will be made both by utilities, through purchase or rebate programs, and by consumers directly. An assumption has also been made about the share of the public agencies' new resource requirements that will be placed on Bonneville under the new contracts. That share will be evaluated at a Bonneville discount rate.

Plausible changes from the reference assumptions would affect the ultimate discount rate somewhat. Because of that both the reference assumptions and a range of assumption values have been examined. The ranges were not intended to try to capture exactly equal weightings on both sides of the reference value, but were simply chosen to show plausible values on both sides. Both the reference value and the ranges are shown in Table N-1 below. Moreover, the final calculated value, described later, has been rounded rather than an attempt being made to capture unrealistic precision.

**Table N-1: Share Assumptions**

| Entity or Item | Reference Share | Range |
|---|---|---|
| BPA share of publics' generation needs | .20 | .10-.30 |
| Generation share of new resource | .60 | .50-.70 |
| Conservation share of new resource | .40 | .50-.30 |
| Utility share of conservation cost | .60 | .50-.70 |
| Consumer share of conservation cost | .40 | .50-.30 |
| Residential share of consumer conservation | .33 | .30-.40 |
| Business share of consumer conservation | .67 | .70-60 |

The second set of assumptions consists of cost of capital estimates for the various decision-making entities described above. As noted, they are based on the most recent forecasts of financial variables as of January 2009 by Global Insight (these assumptions will be updated before the analysis for the final Power Plan). There are five basic inputs to the calculation from this forecast, all averaged over the years 2010-14, except the GDP deflator, which is averaged over 2010-2018[2]: GDP deflator, used to convert to real terms, and nominal 30 year Treasury bond rates, 30 year new conventional mortgage rates, long-term AAA rated municipal bond rates and long-term Baa corporate bond rates. These values are shown in Table N-2 below:

**Table N-2: Basic Financial Assumptions**

| Item | 2010-14 Average |
|---|---|
| GDP deflator | 1.65% |
| 30 year Treasury | 5.03% |
| 30 year new conventional mortgage | 6.08% |
| Long-term AAA municipal bond | 5.09% |
| Long-term Baa corporate bond | 7.13% |

[2] The GDP deflator is used to convert nominal interest rates to real rates, and that conversion is properly done for any year's long-term interest rate using a comparison with long-term expectations of inflation, not any individual year's expectations.

The discount rates that are used for the three major categories of retail load-serving entities (municipals/PUDs, coops and IOUs) are distinguished by their financing costs and estimates can be derived from the above values.

Municipal utilities and public utility districts are assumed to be able to borrow at AAA municipal bond rates, or 3.4 percent in real terms.  Coops are able to finance at about 100 basis points above Treasury rates, implying a rate of 6.03 percent or 4.3 percent in real terms.  Bonneville financing is about 90 basis points above Treasury rates for long-term borrowing, implying a rate of  4.2 percent in real terms.

The discount rates used by regional IOUs in recent integrated resource plans ranged between about 7.0 - 8.3 percent in nominal terms, or 5.1 - 5.6 in real terms, using the inflation rates assumed in the various IRPs[3].  They represent the tax-adjusted weighted average cost of capital (WACC) for the utilities and typically employ the allowed rate of return from the most recent rate case.  They are substantially higher than the other entities' rates both because of the large equity component in their capital structures and because their credit ratings on debt are relatively weaker.

A composite value for the IOUs using the assumptions in this paper can be calculated using the current cost of equity, roughly averaged from the data, and a cost of debt based on the forecast cost of Baa debt, adjusted for its tax deductibility. This is necessary because the effective cost of the debt is lower because it is deductable for corporate income tax purposes, just as home mortgage debt is deductable for personal income tax purposes.  This calculation would give 5.5 percent in real terms, similar to the range of values (5.1 - 5.6 percent) being  used in the integrated resource plans of several of the IOUs using their own calculations and forecasts of inflation.

The approach for assessing decision making by consumers for the consumer-funded portion of the conservation is similar, though it looks mostly at different data.    DOE has recently conducted a study on consumer discount rates[4] for the purpose of evaluating some proposed national lighting standards.  On the residential side, they looked at a range of assets and borrowing sources available to individual consumers[5], weighted by their historic use based on the Federal Reserve Board's Survey of Consumer Finances over a recent 15-year period.  Based on this historic data analysis, DOE calculated a real consumer discount rate of 5.6 percent. (More details of this calculation are in Section 8.2.7.1 of the DOE report cited in Footnote 4.)

We can also look at the Global Insight forecast data, which has been used for the previous calculations in this paper, though this forecasts a much more limited range of assets than the DOE data looked at.  It has one series that can be taken as one kind of  proxy for a consumer

[3] To the extent they are explicit, the IOU IRPs use various inflation rates that are more or less different from the assumption in this paper.  Where the calculation is explicit, the recent IOU discount rates are reported as ranging from 5.1 - 5.6 percent in real terms.

[4] http://www.eere.energy.gov/buildings/appliance_standards/residential/gs_fluorescent_incandescent_tsd.html

[5] Similarly to the approach used by Council in earlier plans, when it took a region consumer's perspective.

discount rate, the 30-year mortgage rate. That forecast rate, averaged over the period 2010-14 is 6.08 percent. Because mortgages are deductable for income-tax purposes, the net cost to consumers is lower. Assuming a 20 percent tax rate gives an after-tax mortgage cost of 4.86 percent or 3.2 percent in real terms. Because that is significantly less than the average calculated by DOE, primarily because of the tax deductibility effect for this particular asset, the final calculation will again use a range for this variable, along with the ranges for the others.

The last item that needs to be calculated is the discount rate for business consumers. DOE also estimated values for this, based on a different approach than they had used for residential consumers. They used the Capital Asset Pricing Model, a widely used approach in financial economics, to calculate the cost of equity for a large sample of commercial and industrial companies. Using the same data base from which the companies were drawn, they extracted estimates of cost of debt, debt/equity ratios and factors relevant to the calculation. Using an estimate of long-term Treasury rates of 5.5 percent (higher than the Global Insight forecast used here, 5.03 percent) and an inflation forecast of 2.3 percent (higher than that used here, 1.65 percent) they derive real industrial and commercial discount rates of 7.5 and 7.3 percent, respectively. (More details are available in Section 8.2.7.2 of the DOE paper cited in Footnote 4.)

In order to make the result somewhat more comparable to the calculations in this paper, the values can be recalculated using the Global Insight forecast of inflation, which has the effect of implying higher real interest rates. That calculation would yield industrial and commercial real discount rates of 7.7 and 7.5 percent respectively.

Note that use of such a rate for business decisions implies relatively unlimited access to capital, which is typically not the case. One approach to capital budgeting in the presence of limited capital is to simply rank projects by net present values; another is to deliberately raise the discount rate to ensure that only the projects that have the most immediate payoffs are pursued. These potential actions can be captured using a higher discount rate for business decisions, in a sensitivity analysis.

In addition to the range of values used for the decision-share assumptions, described earlier in the paper, the recommendation for a discount rate to use in the Council's analysis will be based on a range of real discount rates for business and residential consumer decisions. The final set of assumed values with their ranges is shown below in Table N-3, which partly recapitulates Table N-1. The output of the spreadsheets for the reference and high and low assumption calculations are reproduced in the Attachment. Note that in the calculation of the effect of the individual ranges, the low end is driven by assumptions that drive the result low, which may not necessarily be the low end of any particular range (sometimes the high assumption drives a lower discount rate), and similarly for the high range calculation.

**Table N-3: Discount Rate Summary**

| Item | Value | Range |
|---|---|---|
| **Inflation** | 1.65% | NA |
| **Municipal/PUD real discount rate** | 3.4% | NA |
| **Co-op real discount rate** | 4.3% | NA |
| **IOU real cost of equity** | 8.4% | NA |
| **IOU real cost of debt** | 5.4% | NA |
| **IOU real discount rate (tax-adjusted)** | 5.5% | NA |
| **BPA real discount rate** | 4.2% | NA |
| **Residential consumer real discount rate** | 3.2% | 3%-5% |
| **Business consumer real discount rate** | 7.6% | 7%-9% |
| **Real discount rate for plan** | 4.9% | 4.7%-5.5% |

# CONCLUSIONS

Taking account of the range of assumptions used, the Council has chosen a real discount rate of 5 percent be used in the Sixth Plan analysis. The Council expects that individual entities may well have different values at the point at which they actually make investment decisions.

# Appendix N1: Attachment

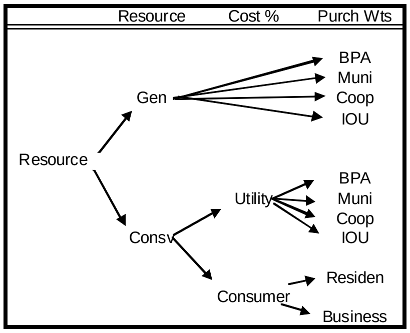
## Figure N1-1: Reference Assumptions

**Weighted Discount Rate Based on Global Insight 3Q09 Forecasts**

| Purchaser | Wtd Disc Rate | Real Disc Rate | Purchaser Weight | Consv Respon Share | Utility Res Respon Share | Regional Load Share |
|---|---|---|---|---|---|---|
| Muni | 0.008 | 0.034 | 0.235 | 0.168 | 0.280 | 0.350 |
| Co-op | 0.003 | 0.043 | 0.067 | 0.048 | 0.080 | 0.100 |
| IOU | 0.025 | 0.055 | 0.462 | 0.330 | 0.550 | 0.550 |
| BPA | 0.003 | 0.042 | 0.076 | 0.054 | 0.090 | |
| Residen Cust | 0.002 | 0.032 | 0.053 | 0.132 | | |
| Business Cust | 0.008 | 0.076 | 0.107 | 0.268 | | |
| Wtd avg | 0.049 | | 1.000 | 1.000 | 1.000 | 1.000 |

**IOU WACC calc**

| | |
|---|---|
| Equity cost | 0.102 |
| Tax adj debt cost | 0.0428 |
| Debt ratio | 0.5 |
| WACC | 0.07239 |
| Real WACC | 0.055 |




| **GI 3Q09 Fcsts 2010-28 avg** | |
|---|---|
| GDP Deflator | 0.0165 |
| **GI 3Q09 Fcsts 2010-14 avgs** | |
| 30 Yr Treasury | 0.0503 |
| 30 Yr New Morgages | 0.0608 |
| AAA Munis | 0.0509 |
| Baa Corporate | 0.0713 |
| **Other factors** | |
| BPA adder on 30 Yr Treasury | 0.0090 |
| Co-op adder on 30 Yr Treasury | 0.0100 |
| Tax-Adj Baa corp | 0.0428 |

| **Assumptions** | | |
|---|---|---|
| Corporate tax rate | | 0.40 |
| Indivdividual tax rate | | 0.20 |
| BPA share of publics' gen res respon | | 0.20 |
| Gen share of future res | | 0.60 |
| Consv share of future res | (CALC) | 0.40 |
| Consumer share of consv cost | | 0.40 |
| Residen sector share of consv | | 0.33 |
| Business sector share of consv | (CALC) | 0.67 |
| Residential real discount rate | | 0.032 |
| Business real discount rate | | 0.076 |

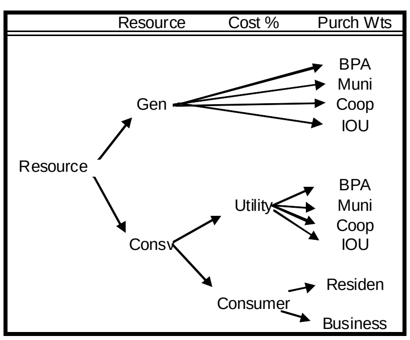
## Figure N1-2: Assumptions that Drive Discount Rate Up

**Weighted Discount Rate Based on Global Insight 3Q09 Forecasts**

| Purchaser | Wtd Disc Rate | Real Disc Rate | Purchaser Weight | Consv Respon Share | Utility Res Respon Share | Regional Load Share |
|---|---|---|---|---|---|---|
| Muni | 0.006 | 0.034 | 0.184 | 0.123 | 0.245 | 0.350 |
| Co-op | 0.002 | 0.043 | 0.053 | 0.035 | 0.070 | 0.100 |
| IOU | 0.023 | 0.055 | 0.413 | 0.275 | 0.550 | 0.550 |
| BPA | 0.004 | 0.042 | 0.101 | 0.068 | 0.135 | |
| Residen Cust | 0.004 | 0.050 | 0.075 | 0.150 | | |
| Business Cust | 0.016 | 0.090 | 0.175 | 0.350 | | |
| Wtd avg | 0.055 | | 1.000 | 1.000 | 1.000 | 1.000 |

**IOU WACC calc**

| | |
|---|---|
| Equity cost | 0.102 |
| Tax adj debt cost | 0.0428 |
| Debt ratio | 0.5 |
| WACC | 0.07239 |
| Real WACC | 0.055 |




| **GI 3Q09 Fcsts 2010-28 avg** | |
|---|---|
| GDP Deflator | 0.0165 |
| **GI 3Q09 Fcsts 2010-14 avgs** | |
| 30 Yr Treasury | 0.0503 |
| 30 Yr New Morgages | 0.0608 |
| AAA Munis | 0.0509 |
| Baa Corporate | 0.0713 |
| **Other factors** | |
| BPA adder on 30 Yr Treasury | 0.0090 |
| Co-op adder on 30 Yr Treasury | 0.0100 |
| Tax-Adj Baa corp | 0.0428 |

| **Assumptions** | | |
|---|---|---|
| Corporate tax rate | | 0.40 |
| Indivdividual tax rate | | 0.20 |
| BPA share of publics' gen res respon | | 0.30 |
| Gen share of future res | | 0.50 |
| Consv share of future res | (CALC) | 0.50 |
| Consumer share of consv cost | | 0.50 |
| Residen sector share of consv | | 0.30 |
| Business sector share of consv | (CALC) | 0.70 |
| Residential real discount rate | | 0.050 |
| Business real discount rate | | 0.090 |

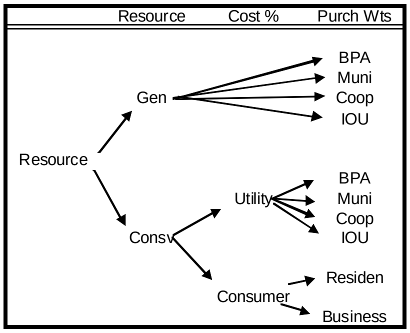
# Figure N1-3: Assumptions that Drive Discount Rate Down

**Weighted Discount Rate Based on Global Insight 3Q09 Forecasts**

| Purchaser | Wtd Disc Rate | Real Disc Rate | Purchaser Weight | Consv Respon Share | Utility Res Respon Share | Regional Load Share |
|---|---|---|---|---|---|---|
| Muni | 0.010 | 0.034 | 0.287 | 0.221 | 0.315 | 0.350 |
| Co-op | 0.004 | 0.043 | 0.082 | 0.063 | 0.090 | 0.100 |
| IOU | 0.028 | 0.055 | 0.501 | 0.385 | 0.550 | 0.550 |
| BPA | 0.002 | 0.042 | 0.041 | 0.032 | 0.045 | |
| Residen Cust | 0.001 | 0.030 | 0.036 | 0.120 | | |
| Business Cust | 0.004 | 0.070 | 0.054 | 0.180 | | |
| Wtd avg | 0.047 | | 1.000 | 1.000 | 1.000 | 1.000 |

**IOU WACC calc**

| | |
|---|---|
| Equity cost | 0.102 |
| Tax adj debt cost | 0.0428 |
| Debt ratio | 0.5 |
| WACC | 0.07239 |
| Real WACC | 0.055 |




**GI 3Q09 Fcsts 2010-28 avg**

| | |
|---|---|
| GDP Deflator | 0.0165 |

**GI 3Q09 Fcsts 2010-14 avgs**

| | |
|---|---|
| 30 Yr Treasury | 0.0503 |
| 30 Yr New Morgages | 0.0608 |
| AAA Munis | 0.0509 |
| Baa Corporate | 0.0713 |

**Other factors**

| | |
|---|---|
| BPA adder on 30 Yr Treasury | 0.0090 |
| Co-op adder on 30 Yr Treasury | 0.0100 |
| Tax-Adj Baa corp | 0.0428 |

**Assumptions**

| | | |
|---|---|---|
| Corporate tax rate | | 0.40 |
| Indivdividual tax rate | | 0.20 |
| BPA share of publics' gen res respon | | 0.10 |
| Gen share of future res | | 0.70 |
| Consv share of future res | (CALC) | 0.30 |
| Consumer share of consv cost | | 0.30 |
| Residen sector share of consv | | 0.40 |
| Business sector share of consv | (CALC) | 0.60 |
| Residential real discount rate | | 0.030 |
| Business real discount rate | | 0.070 |

# Appendix O: Calculation of Revenue Requirements and Customer Bills

Introduction ... 1
Methodology for Estimating Average Revenue Requirements ... 1
Estimating Existing Power System Cost: ... 2
Estimating Future Power System Cost: ... 2
Cost of $CO_2$ Penalties ... 3
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Calculated Monthly Bills ... 5
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## INTRODUCTION

In this analysis we present the methodology used to estimate the average revenue requirement per megawatt-hour and average residential bills for the least risk resource plan under various scenarios. The scenarios are defined in Chapter 10 ("Resource Strategy") of the Plan. These average revenue requirements and bills reflect the impact of conservation investment, $CO_2$ costs and other resource options for each scenario.

It should be emphasized that these average revenue requirements per megawatt-hour are not intended as estimates of retail electricity rates, since our methodology is a gross simplification of the detailed calculations and regulatory approval process that rates have to go through. Actual rate setting procedures and calculations will vary across utilities, class of customers and regulatory jurisdictions. The average revenue requirements per megawatt-hour calculations presented here are averaged across all customer classes, so relative changes among classes are not reflected. The results should, however, be valid for comparison across scenarios.

It should also be emphasized that some events will affect the revenue requirements of some parts of the region more than others. The result will be more significant impacts on some ratepayers (and smaller impacts on other ratepayers) than if the effects were distributed evenly. For example, Table O-1 shows a difference of 4.4 percent between the levelized regional revenue requirement per megawatt-hour in the "Carbon Risk" case and the "$45/Ton $CO_2$ Cost" case. If only half of the region is affected by the difference in $CO_2$ costs, the impact would be concentrated on half the region's ratepayers. The result would be an impact of 8.8 percent on the levelized revenue requirements per megawatt-hour to be recovered from those ratepayers, while the other half of the region's ratepayers would see no change at all.

## METHODOLOGY FOR ESTIMATING AVERAGE REVENUE REQUIREMENTS

To estimate the average revenue requirement per megawatt-hour, dollars of revenue requirements are divided by the total retail sales of electricity. To calculate dollars of revenue requirements; the continuing fixed cost of the existing power system was added to the development and operational cost of the future power system. That fixed cost of the existing power system is assumed not to change, remaining at 2008 levels in real terms over the planning horizon. This implicitly assumes that depreciation in cost of existing power system is equal to capital additions to maintain the existing power system. The future system costs consist of the capital cost of the new resources and the non-capital cost of the existing and future power system. The future system cost is the cost measured in the Resource Portfolio Model (RPM). The consumer's contribution to conservation measures is netted from the total system cost calculated in the Resource Portfolio Model. It should be noted that the average revenue requirements and bills shown below are an average of the revenue requirements and bills under 750 possible futures.

## *Estimating Existing Power System Cost:*

The total regional revenue requirement for the power system in 2008 is reported to be $11.6 billion dollars. It was estimated that about 85 percent of that requirement was due to fixed costs, which amounts to about $9.8 billion dollars per year. Figure O-1 illustrates the relative importance of this component; in the Carbon Risk case it accounts for about $60 per megawatt-hour of the total revenue requirement per megawatt-hour.

## *Estimating Future Power System Cost:*

The cost of the future power system calculated in the Resource Portfolio Model (RPM) consists of levelized costs of conservation resources and capital and non-capital costs of other new resources as well as the variable cost of existing system. However, general practice among utilities for at least the last decade has been to "expense" their conservation expenditures, that is, to recover them in rates immediately rather than capitalize the expenditures and recover them (and accumulated interest) over the life of the conservation measures. To reflect this practice in the Council's estimates of average revenue requirement per megawatt-hour, estimated conservation costs "as incurred" were substituted for the levelized conservation costs[1] used in the RPM. Based on recent history, $300 million per year of conservation expenses were assumed to be included in the 2008 revenue requirement; so that conservation expenses in the future would only increase revenue requirements to the extent they are higher than $300 million per year.

To estimate these "as incurred" costs, Council staff converted the levelized costs of the conservation developed by the RPM into a single payment to be made at the time of the conservation measures' installation. This payment covers the full installation cost of the measures, and their administration cost over their lifetime, expressed as 2006 dollars per average megawatt of yearly savings. The Council's ProCost model was run iteratively to produce levelized costs equivalent to the average cost of the conservation developed by the RPM at the average life of the conservation measures in the supply curve. This approach assures the calculation method is consistent with the method used to develop the conservation supply curve costs used by the RPM.

[1] The conservation premium used to select the level of conservation acquisition does not change the cost of conservation resources and the levelized cost of conservation and the cash-flow of expensed conservation do not differ greatly if conservation acquisition levels are increasing smoothly and do not have significant jumps from one year to next.

The average life of conservation measures was calculated by weighting each measure's lifetime by its contribution to savings in the conservation supply curve. These annual expense costs were reduced to reflect that approximately 65 percent of the costs are paid by the utility system and would be reflected in rates. The costs were then adjusted upward to compensate for the 10 percent Regional Power Act Conservation Credit which had been applied to costs in the ProCost model. The result is an average utility cost of $2.5 million per average megawatt of -yearly savings.

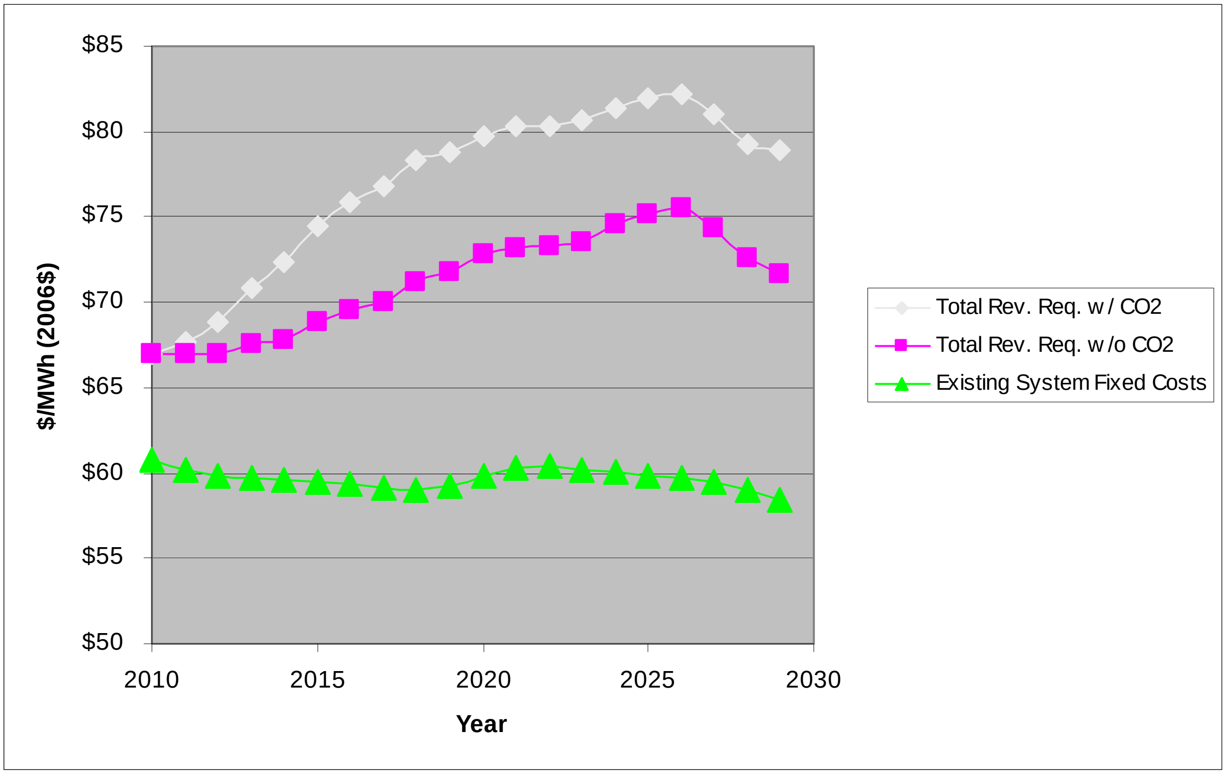
Figure O-1 illustrates that the fixed cost of the existing power system is about $60 per megawatt-hour, and the addition of the variable cost of the existing system and the full costs of new resources (including conservation) after 2009 raises the total revenue requirement per megawatt-hour by up to $23 per megawatt-hour, depending on the year and how $CO_2$ penalties are counted. The total revenue requirement per megawatt-hour declines after the mid-2020s mostly due to declining conservation and RPS acquisitions[2].

## *Cost of $CO_2$ Penalties*

The default accounting in the Regional Portfolio Model includes cost of $CO_2$ penalties, when they are in force, as though a tax were paid on every ton of $CO_2$ emitted. However, given uncertainty regarding the impact of $CO_2$ costs on power system revenue requirements, the impacts on revenue requirements are calculated with and without $CO_2$ costs. To the extent that $CO_2$ penalties are included in the power system revenue requirement, they are recovered from the consumers served by the generators emitting the $CO_2$, regardless of whether the generators are physically in the region or not. That is, $CO_2$ emissions from power exported from the region are subtracted from $CO_2$ emissions due to regional load and $CO_2$ emissions from power imported to meet regional load are added to $CO_2$ emissions due to regional load. The addition of $CO_2$ penalties as though they are paid on every ton of emissions raises average revenue requirements by amounts that vary between $5 and $7 per megawatt-hour over most of the 2010-2029 period, as shown in Figure O-1.

[2] Three factors contribute to drop-off in revenue requirement; a reduced level of discretionary conservation acquisition, a reduced level of RPS acquisitions and expensing of the conservation expenditure.

**Figure O-1: Average Revenue Requirement Disaggregated by Component (Carbon Risk Case)**

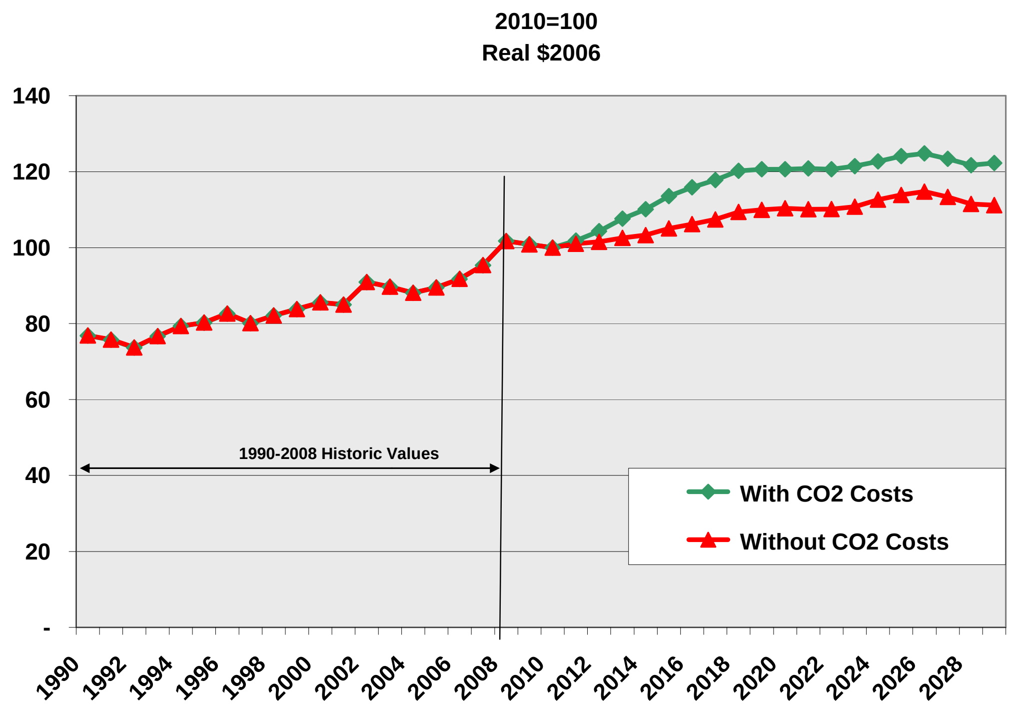



## *Calculated Average Revenue Requirements*

The above methodology, averaged across the 750 futures simulated by the Regional Portfolio Model, results in the annual and levelized revenue requirements per megawatt-hour for the period 2010 through 2029. The results in Tables O-1 and O-2 represent 9 scenarios defined in Chapter 10 ("Resource Strategy"). The average revenue requirement in 2008 across all sectors was estimated to be about 6.5 cents per kilowatt-hour or $65 dollars per megawatt-hour of sales. As an illustrative example, the Carbon Risk" case projects the average revenue requirement to increase to about $67 per megawatt-hour by 2010. By 2030 the case projects revenue requirements to be between $72 and $79 dollars per megawatt-hour depending on whether $CO_2$ penalties are paid on all emissions (Table O-1) or whether allowances are distributed to utilities free (Table O-2).

Comparison of annual electric revenue collected in the region, for the past 19 years, with the forecasted future revenue requirement is presented in the figure O-2. To make the comparison across time appropriate all costs were converted to 2006 dollars and then indexed so that 2010 is has an index value of 100. Between 1990 and 2008, revenue requirement increased by approximately 20 index points. In the future period, the revenue requirement is expected to increase from an index of 100 points to 110 to 120 points, depending on how $CO_2$ costs are incorporated into the revenue requirement. The future increase in rates is smaller than the historic experience.

**Figure O-2 Comparison of Historic Revenue Collected and Future Revenue Requirement**




## *Calculated Monthly Bills*

Representative residential bills are estimated beginning with the total revenue requirements calculated earlier, allocating the residential share of those annual revenue requirements (about 45 percent) to the residential sector, dividing by the projected number of households in future years and dividing by 12 to arrive at monthly bills per household. The results of those calculations are shown in Tables O-3 and O-4.

**Table O-1: Average Revenue Requirements per Megawatt-hour for Least Risk Portfolios by Scenario - $CO_2$ Costs Included (All average revenue requirements are expressed in $2006/MWh (=mills/kWh))**

| | Carbon Risk | Current Policy | No Policy | No RPS | $45/Ton $CO_2$ Cost | Coal Retirement w/o $CO_2$ | Coal Retirement w/ $CO_2$ | No Conservation | Lower Snake Dam Breach |
|---|---|---|---|---|---|---|---|---|---|
| **Case Identifier** | **L813** | **L813 G** | **L813 I** | **L813 H** | **L813 D** | **L813 B** | **L813 J** | **L813 A** | **L813 K** |
| 2010 | 66.98 | 66.92 | 66.9 | 66.98 | 75.19 | 66.96 | 66.98 | 63.78 | 67.01 |
| 2011 | 67.62 | 66.98 | 66.9 | 67.62 | 75.86 | 67.04 | 67.62 | 64.07 | 67.65 |
| 2012 | 68.82 | 66.90 | 66.8 | 68.82 | 76.18 | 67.02 | 68.83 | 64.93 | 68.89 |
| 2013 | 70.89 | 67.39 | 67.3 | 70.89 | 77.13 | 67.75 | 70.92 | 66.73 | 70.98 |
| 2014 | 72.34 | 67.60 | 67.4 | 72.31 | 77.65 | 68.42 | 72.42 | 68.23 | 72.42 |
| 2015 | 74.47 | 68.40 | 67.8 | 74.21 | 78.61 | 69.87 | 74.59 | 70.43 | 74.55 |
| 2016 | 75.90 | 69.00 | 68.0 | 75.50 | 78.98 | 71.19 | 76.11 | 72.09 | 75.96 |
| 2017 | 76.84 | 69.30 | 67.9 | 76.47 | 79.28 | 72.18 | 77.12 | 73.38 | 76.90 |
| 2018 | 78.31 | 70.23 | 68.4 | 77.70 | 80.17 | 73.39 | 78.62 | 74.60 | 78.40 |
| 2019 | 78.85 | 70.80 | 68.6 | 78.23 | 80.39 | 74.23 | 79.22 | 75.31 | 78.96 |
| 2020 | 79.68 | 71.62 | 69.1 | 78.85 | 80.80 | 75.14 | 80.08 | 76.46 | 82.96 |
| 2021 | 80.33 | 71.75 | 69.2 | 79.61 | 81.02 | 75.31 | 80.68 | 77.28 | 83.56 |
| 2022 | 80.36 | 71.66 | 69.3 | 79.63 | 80.94 | 75.45 | 80.77 | 78.34 | 83.75 |
| 2023 | 80.65 | 71.52 | 69.3 | 80.28 | 80.96 | 75.68 | 81.10 | 79.69 | 84.23 |
| 2024 | 81.32 | 72.42 | 69.5 | 80.20 | 81.60 | 76.69 | 81.76 | 80.59 | 84.83 |
| 2025 | 81.96 | 72.76 | 69.8 | 80.63 | 81.84 | 77.35 | 82.39 | 81.48 | 85.47 |
| 2026 | 82.21 | 72.90 | 70.1 | 80.94 | 82.05 | 77.84 | 82.65 | 82.47 | 85.74 |
| 2027 | 80.99 | 71.33 | 69.1 | 80.26 | 81.43 | 76.79 | 81.53 | 82.74 | 84.95 |
| 2028 | 79.28 | 69.76 | 67.5 | 78.50 | 79.35 | 75.16 | 79.87 | 83.59 | 83.33 |
| 2029 | 78.86 | 69.12 | 66.8 | 77.62 | 78.61 | 74.39 | 79.41 | 84.19 | 82.35 |
| | | | | | | | | | |
| **Levelized Rates** | **$75.61** | **$69.49** | **$68.12** | **$75.15** | **$78.95** | **$71.96** | **$75.86** | **$73.20** | **$77.00** |
| **Annual Rate of Growth** | 0.9% | 0.2% | 0.0% | 0.8% | 0.2% | 0.6% | 0.9% | 1.5% | 1.1% |
| **Percent Change from Carbon Risk case** | | **-8.1%** | **-9.9%** | **-0.6%** | **4.4%** | **-4.8%** | **0.3%** | **-3.2%** | **1.8%** |

**Table O-2: Average Revenue Requirement per Megawatt-hour for Least Risk Plans by Scenario - $CO_2$ Costs Not Included (All average revenue requirements are expressed in $2006/MWh (=mills/kWh))**

| | Carbon Risk | Current Policy | No Policy | No RPS | $45/Ton $CO_2$ Cost | Coal Retirement w/o $CO_2$ | Coal Retirement w/ $CO_2$ | No Conservation | Lower Snake Dam Breach |
|---|---|---|---|---|---|---|---|---|---|
| **Case Identifier** | **L813** | **L813 G** | **L813 I** | **L813 H** | **L813 D** | **L813 B** | **L813 J** | **L813 A** | **L813 K** |
| 2010 | 66.96 | 66.92 | 66.89 | 66.96 | 69.01 | 66.96 | 66.96 | 63.75 | 66.98 |
| 2011 | 67.01 | 66.98 | 66.93 | 67.01 | 69.01 | 67.04 | 67.02 | 63.45 | 67.05 |
| 2012 | 66.95 | 66.90 | 66.82 | 66.95 | 68.97 | 67.02 | 66.96 | 62.96 | 67.01 |
| 2013 | 67.53 | 67.39 | 67.27 | 67.53 | 69.66 | 67.75 | 67.58 | 63.12 | 67.62 |
| 2014 | 67.84 | 67.60 | 67.39 | 67.79 | 70.01 | 68.42 | 67.97 | 63.27 | 67.93 |
| 2015 | 68.87 | 68.40 | 67.80 | 68.49 | 70.81 | 69.87 | 69.07 | 64.10 | 68.95 |
| 2016 | 69.53 | 69.00 | 67.96 | 68.88 | 71.40 | 71.19 | 69.88 | 64.79 | 69.61 |
| 2017 | 70.04 | 69.30 | 67.88 | 69.30 | 71.69 | 72.18 | 70.51 | 65.36 | 70.13 |
| 2018 | 71.22 | 70.23 | 68.42 | 70.14 | 72.68 | 73.39 | 71.75 | 65.94 | 71.33 |
| 2019 | 71.82 | 70.80 | 68.59 | 70.66 | 73.24 | 74.23 | 72.46 | 66.36 | 71.96 |
| 2020 | 72.85 | 71.62 | 69.06 | 71.40 | 74.03 | 75.14 | 73.55 | 67.26 | 74.50 |
| 2021 | 73.17 | 71.75 | 69.20 | 72.00 | 74.27 | 75.31 | 73.84 | 67.46 | 74.78 |
| 2022 | 73.35 | 71.66 | 69.27 | 72.30 | 74.22 | 75.45 | 74.11 | 68.52 | 75.06 |
| 2023 | 73.53 | 71.52 | 69.35 | 73.06 | 74.19 | 75.68 | 74.32 | 69.95 | 75.49 |
| 2024 | 74.62 | 72.42 | 69.53 | 73.26 | 75.18 | 76.69 | 75.39 | 70.78 | 76.46 |
| 2025 | 75.19 | 72.76 | 69.83 | 73.36 | 75.60 | 77.35 | 75.95 | 71.29 | 77.05 |
| 2026 | 75.55 | 72.90 | 70.08 | 73.71 | 75.88 | 77.84 | 76.30 | 72.14 | 77.42 |
| 2027 | 74.37 | 71.33 | 69.06 | 73.13 | 75.16 | 76.79 | 75.25 | 72.17 | 76.70 |
| 2028 | 72.59 | 69.76 | 67.46 | 71.39 | 72.94 | 75.16 | 73.54 | 72.83 | 75.06 |
| 2029 | 71.67 | 69.12 | 66.85 | 69.92 | 71.89 | 74.39 | 72.59 | 72.99 | 73.64 |
| | | | | | | | | | |
| **Levelized Rates** | **$70.53** | **$69.49** | **$68.12** | **$69.82** | **$71.97** | **$71.96** | **$70.96** | **$66.52** | **$71.30** |
| **Annual Rate of Growth** | 0.4% | 0.2% | 0.0% | 0.2% | 0.2% | 0.6% | 0.4% | 0.7% | 0.5% |
| **Percent Change from Carbon Risk case** | | **-1.5%** | **-3.4%** | **-1.0%** | **2.0%** | **2.0%** | **0.6%** | **-5.7%** | **1.1%** |

**Table O-3: Average Residential Bills for Least Risk Portfolios by Scenario - $CO_2$ Costs Included (Bills are expressed in 2006$/month/household)**

| | Carbon Risk | Current Policy | No Policy | No RPS | $45/Ton $CO_2$ Cost | Coal Retirement w/o $CO_2$ | Coal Retirement w/ $CO_2$ | No Conservation | Lower Snake Dam Breach |
|---|---|---|---|---|---|---|---|---|---|
| **Case Identifier** | **L813** | **L813 G** | **L813 I** | **L813 H** | **L813 D** | **L813 B** | **L813 J** | **L813 A** | **L813 K** |
| 2010 | 82.28 | 82.21 | 82.17 | 82.28 | 92.36 | 82.24 | 82.28 | 78.77 | 82.30 |
| 2011 | 82.44 | 81.67 | 81.63 | 82.44 | 92.50 | 81.73 | 82.44 | 79.25 | 82.47 |
| 2012 | 83.14 | 80.85 | 80.78 | 83.14 | 92.05 | 80.96 | 83.15 | 80.36 | 83.20 |
| 2013 | 84.47 | 80.35 | 80.26 | 84.47 | 91.92 | 80.73 | 84.51 | 82.34 | 84.53 |
| 2014 | 85.14 | 79.65 | 79.48 | 85.10 | 91.40 | 80.53 | 85.24 | 84.10 | 85.18 |
| 2015 | 86.47 | 79.56 | 78.97 | 86.18 | 91.27 | 81.15 | 86.62 | 86.68 | 86.49 |
| 2016 | 86.94 | 79.22 | 78.17 | 86.49 | 90.45 | 81.57 | 87.19 | 88.63 | 86.93 |
| 2017 | 87.11 | 78.79 | 77.37 | 86.69 | 89.85 | 81.88 | 87.43 | 90.43 | 87.08 |
| 2018 | 87.69 | 78.94 | 77.12 | 87.01 | 89.73 | 82.25 | 88.05 | 92.08 | 87.68 |
| 2019 | 86.84 | 78.34 | 76.15 | 86.16 | 88.49 | 81.84 | 87.25 | 92.85 | 86.83 |
| 2020 | 85.74 | 77.49 | 75.02 | 84.85 | 86.90 | 80.96 | 86.16 | 93.65 | 89.10 |
| 2021 | 84.81 | 76.24 | 73.87 | 84.05 | 85.49 | 79.65 | 85.17 | 94.39 | 88.04 |
| 2022 | 83.64 | 75.13 | 73.00 | 82.87 | 84.20 | 78.70 | 84.06 | 95.83 | 86.97 |
| 2023 | 83.24 | 74.43 | 72.57 | 82.85 | 83.51 | 78.30 | 83.69 | 98.08 | 86.72 |
| 2024 | 83.14 | 74.73 | 72.18 | 81.99 | 83.39 | 78.62 | 83.59 | 99.67 | 86.51 |
| 2025 | 83.14 | 74.55 | 72.01 | 81.79 | 82.99 | 78.71 | 83.57 | 101.37 | 86.46 |
| 2026 | 82.72 | 74.15 | 71.76 | 81.43 | 82.54 | 78.59 | 83.15 | 103.16 | 86.02 |
| 2027 | 80.89 | 72.12 | 70.27 | 80.08 | 81.24 | 76.95 | 81.41 | 104.02 | 84.51 |
| 2028 | 78.97 | 70.48 | 68.53 | 77.98 | 78.88 | 75.10 | 79.53 | 105.65 | 82.50 |
| 2029 | 78.50 | 69.84 | 67.92 | 77.01 | 78.11 | 74.30 | 79.02 | 106.95 | 81.42 |
| | | | | | | | | | |
| **Levelized Rates** | **$84.18** | **$77.91** | **$76.66** | **$83.67** | **$88.12** | **$80.27** | **$84.44** | **$90.51** | **$85.46** |
| **Annual Rate of Growth** | -0.25% | -0.9% | -1.0% | -0.3% | -0.9% | -0.5% | -0.2% | 1.6% | -0.1% |
| **Percent Change from CO2 Risk case** | | **-7.4%** | **-8.9%** | **-0.6%** | **4.7%** | **-4.6%** | **0.3%** | **7.5%** | **1.5%** |

**Table O-4: Average Residential Bills for Least Risk Portfolios by Case - $CO_2$ Cost Not Included (Bills are expressed in 2006$/month/household)**

| | Carbon Risk | Current Policy | No Policy | No RPS | $45/Ton $CO_2$ Cost | Coal Retirement w/o $CO_2$ | Coal Retirement w/ $CO_2$ | No Conservation | Lower Snake Dam Breach |
|---|---|---|---|---|---|---|---|---|---|
| **Case Identifier** | **L813** | **L813 G** | **L813 I2** | **L813 H** | **L813 D** | **L813 B** | **L813 J** | **L813 A** | **L813 K** |
| 2010 | 82.24 | 82.21 | 82.17 | 82.24 | 84.77 | 82.24 | 82.24 | 78.73 | 82.27 |
| 2011 | 81.70 | 81.67 | 81.63 | 81.70 | 84.15 | 81.73 | 81.71 | 78.48 | 81.73 |
| 2012 | 80.88 | 80.85 | 80.78 | 80.88 | 83.34 | 80.96 | 80.89 | 77.93 | 80.94 |
| 2013 | 80.46 | 80.35 | 80.26 | 80.46 | 83.01 | 80.73 | 80.52 | 77.88 | 80.53 |
| 2014 | 79.84 | 79.65 | 79.48 | 79.79 | 82.40 | 80.53 | 80.00 | 77.99 | 79.90 |
| 2015 | 79.97 | 79.56 | 78.97 | 79.53 | 82.22 | 81.15 | 80.20 | 78.88 | 80.00 |
| 2016 | 79.65 | 79.22 | 78.17 | 78.90 | 81.77 | 81.57 | 80.05 | 79.65 | 79.65 |
| 2017 | 79.40 | 78.79 | 77.37 | 78.57 | 81.24 | 81.88 | 79.94 | 80.55 | 79.41 |
| 2018 | 79.75 | 78.94 | 77.12 | 78.55 | 81.35 | 82.25 | 80.35 | 81.39 | 79.78 |
| 2019 | 79.11 | 78.34 | 76.15 | 77.82 | 80.62 | 81.84 | 79.81 | 81.82 | 79.13 |
| 2020 | 78.39 | 77.49 | 75.02 | 76.83 | 79.61 | 80.96 | 79.14 | 82.38 | 80.02 |
| 2021 | 77.24 | 76.24 | 73.87 | 76.00 | 78.37 | 79.65 | 77.95 | 82.40 | 78.79 |
| 2022 | 76.34 | 75.13 | 73.00 | 75.24 | 77.20 | 78.70 | 77.12 | 83.82 | 77.94 |
| 2023 | 75.88 | 74.43 | 72.57 | 75.39 | 76.53 | 78.30 | 76.70 | 86.09 | 77.72 |
| 2024 | 76.29 | 74.73 | 72.18 | 74.90 | 76.83 | 78.62 | 77.07 | 87.54 | 77.97 |
| 2025 | 76.28 | 74.55 | 72.01 | 74.42 | 76.67 | 78.71 | 77.05 | 88.69 | 77.95 |
| 2026 | 76.02 | 74.15 | 71.76 | 74.15 | 76.33 | 78.59 | 76.77 | 90.24 | 77.67 |
| 2027 | 74.28 | 72.12 | 70.27 | 72.97 | 74.98 | 76.95 | 75.14 | 90.72 | 76.30 |
| 2028 | 72.30 | 70.48 | 68.53 | 70.91 | 72.52 | 75.10 | 73.23 | 92.05 | 74.32 |
| 2029 | 71.34 | 69.84 | 67.92 | 69.37 | 71.44 | 74.30 | 72.24 | 92.72 | 72.81 |
| | | | | | | | | | |
| **Levelized Rates** | **$78.66** | **$77.91** | **$76.66** | **$77.89** | **$80.29** | **$80.27** | **$79.11** | **$82.24** | **$79.33** |
| **Annual Rate Of Growth** | -0.7% | -0.9% | -1.0% | -0.9% | -0.9% | -0.5% | -0.7% | 0.9% | -0.6% |
| **Percent change from CO2 Risk case** | | **-1.0%** | **-2.5%** | **-1.0%** | **2.1%** | **2.0%** | **0.6%** | **4.6%** | **0.9%** |

## *Analysis of Differences in Revenue Requirement per Megawatt-hour among Cases*

The tables can be used to contrast rates and bills among cases in almost infinite combinations, but a few illustrations should make it possible for regional analysts to pursue their interests using the tables. For example, consider the impact of a reduction in conservation potential, assuming that carbon allowances are granted free so that carbon penalties are not included in retail revenue requirements.

The “Carbon Risk” case can be compared to the “Zero Conservation” case, which eliminates conservation from the resource portfolio. Comparison of the “Carbon Risk” and “Zero Conservation” columns of Tables O-2 and O-4 shows that when conservation is eliminated, average revenue requirements per megawatt-hour decrease until the 2028 and then increase. Bills are lower with no conservation for a few years, but by 2017 they are higher. The same results are shown graphically in Figures O-2 and O-3 (i.e. the “Zero Conservation” bars are lower than the Carbon Risk” bars until the mid-2020s, then higher). The data shown in Figure O-2 are from the Carbon Risk” and “Zero Conservation” column in Table O-2 and the data shown in Figure O-3 are from the same columns in Table O-4.

**Figure O-2 Average Revenue Requirements per Megawatt-Hour Comparison CO2 Costs Not Included**

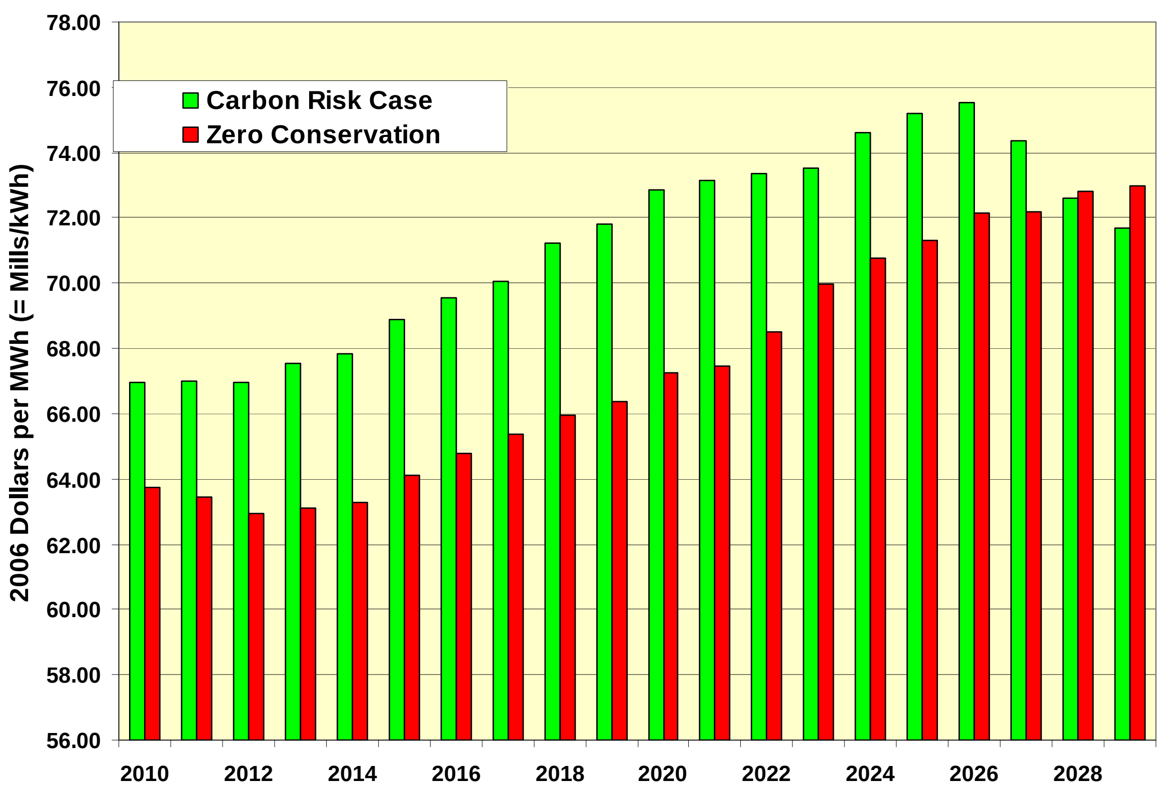
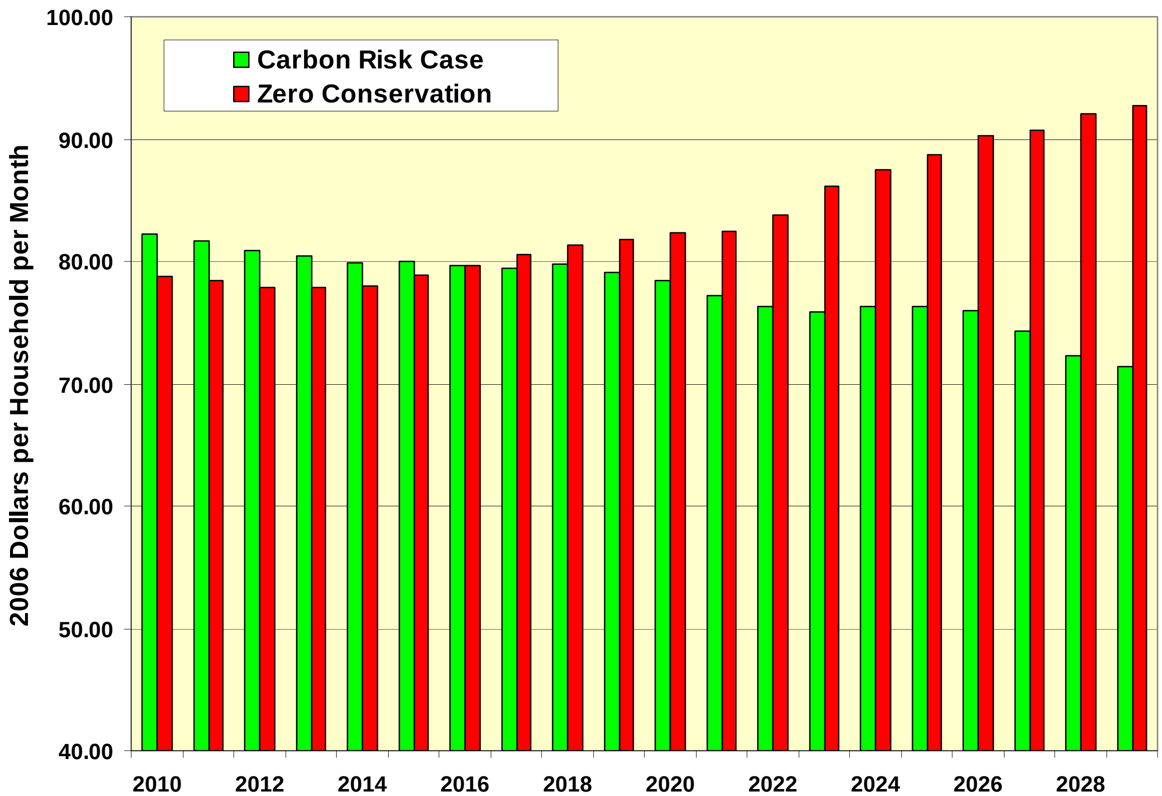


**Figure O-3 Typical Residential Electricity Bill Comparison - CO2 Costs Not Included**




Another illustration of potential analysis using Tables O-1 through O-4 (and the Excel workbook that lies behind them) is a comparison of the average revenue requirement per megawatt-hour and bills, each levelized across the 2010-2029 period, across the 9 scenarios included in the tables. Figure O-4 compares levelized average revenue requirement per megawatt-hour across all scenarios, and Figure O-5 compares levelized bills, both with CO2 costs excluded. Levelized revenue requirement per megawatt-hour (from Table O-2) range from a low of \$67 per megawatt-hour for the "Zero Conservation" scenario to \$72 per megawatt-hour for the "\$45/Ton CO2 Cost" scenario. Levelized bills range from \$77 for the "No Policy" scenario to \$82 for the "Zero Conservation" scenario.

**Figure O-4:  Levelized Revenue Requirement per Megawatt-Hour by Scenario**
**CO2 Costs Not Included**

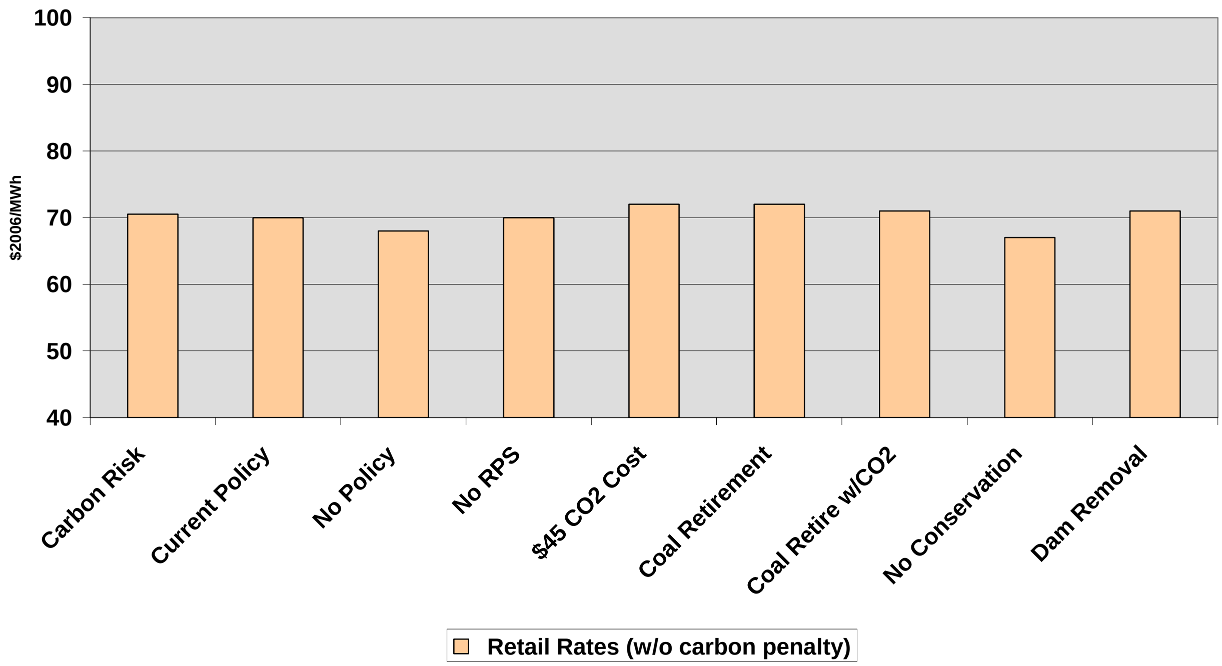
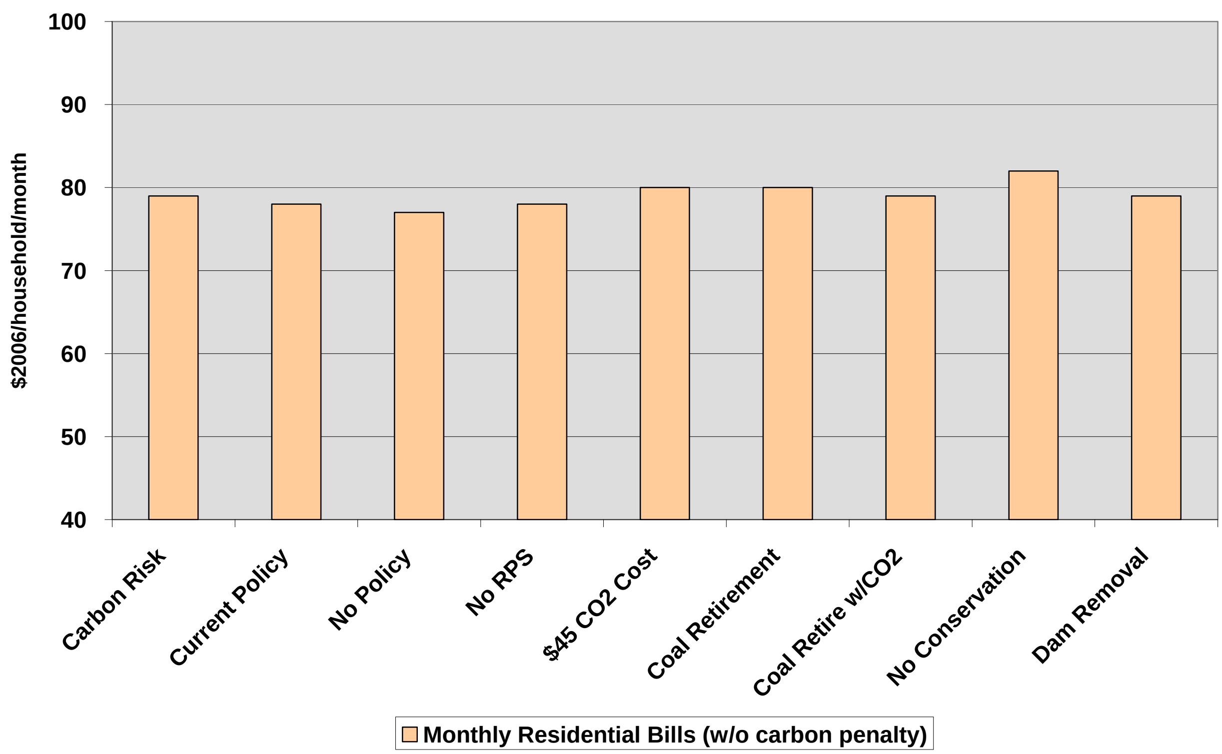



**Figure O-5:  Levelized Typical Residential Electricity Bills by Scenario**
**CO2 Costs Not Included**



## Difference in Growth Rates

In the above analysis we have shown the average annual increase in revenue requirement, rates and bills. The growth rate for revenue requirement and bills are different, due to the impact of growth in number of households in the region. The number of households is growing at a higher rate than the revenue requirement, resulting in a slower growth rate for residential bills. The growth rate for the revenue requirement is also different than the growth rate in average rates due to growth in sales. The following two tables show the decomposition of the residential bills and average rate for the least risk plan for Carbon Risk scenario, excluding cost of CO2 tax.

**Table O-5: Decomposition of growth rate in Revenue Requirement and Bills**

| Annual Growth Rate in Revenue requirement | Annual growth rate in number of households | Net effect on average residential bill |
|---|---|---|
| 0.5% | 1.2% | -0.7% |

**Table O-6: Decomposition of growth rate in Revenue Requirement and Average Rate**

| Annual Growth Rate in Revenue requirement | Annual growth rate in Sales | Net effect on average revenue requirement per kilowatt hour |
|---|---|---|
| 0.5% | 0.2% | 0.3% |

# Appendix P: Methodology for Determining Quantifiable Environmental Costs and Benefits

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## BACKGROUND

Section 4(e)(3)(C) of the Act requires the Council to include in its power plan a "methodology for determining quantifiable environmental costs and benefits." The purpose of this Appendix is both to describe the Council's methodology for determining environmental costs and benefits and to explain how the Council has assessed environmental costs and benefits in its resource cost estimates.

The Council's Power Plan is based on the most cost-effective resources to meet the electricity needs of the region. The Act specifies priorities for types of resources. Energy efficiency is first priority and it receives a 10 percent cost credit compared to other alternatives. Efficiency is followed by renewable resources, high-efficiency resources, and finally, all others. With the exception of efficiency improvements, the other priorities are only tie breakers. It is cost that determines the most cost-effective resources for the Council's Plan.

The Act specifies that the costs of a conservation or generating resource are to include an estimate of "all direct costs" over the effective life of the resource, including "quantifiable environmental costs and benefits ... directly attributable" to the resource. More precisely, Section 3(4)(B) provides:

> For purposes of this paragraph, 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.**[1]

An entire regulatory structure is in place at the national, state, and local levels to address environmental effects of various economic activities, including those related to the production and use of electricity. These regulations represent a collective choice of society about the

[1] The language can be read to apply only to potential Bonneville resource acquisitions and only following a particular determination by the Bonneville Administrator. Still, the Council takes this as instructive for evaluating the costs of all new resources considered in its Power Planning. In addition, Section 4(e)(3)(C) of the Act requires the Council to include in its power plan the "methodology for determining quantifiable environmental costs and benefits." Thus the purpose of this Appendix is both to describe the Council's methodology for determining environmental costs and benefits and to explain how the Council has assessed environmental costs and benefits in its resource cost estimates.

desirable and economically efficient mitigation of environmental effects. Where policies exist and are considered up to date, the Council assumes that policy makers have balanced environmental damage against mitigation alternatives and costs to determine the desirable levels of mitigation. However, regulatory policies evolve over time as better understanding of environmental effects is gained, previously negligible impacts become significant due to expansion of human activity, and the values of society change. Where policies have not been developed or are actively being considered for revision, additional mitigation costs should be considered in planning.

Most regulatory policies do not require full abatement of impacts, but rather seek the balance between the cost of mitigation and the damages of residual impacts. Environmental effects that remain after regulatory solutions are implemented should not be ignored, however they may not be quantifiable. In addition, some resource choices have accompanying environmental benefits that should be considered.

The Council's methodology for consideration of environmental costs in developing its power plan is described below. Bonneville also should follow this methodology, in addition to applicable existing requirements and regulations, when considering expenditures related to resource acquisition.

# METHODOLOGY

There are four components to the Council's methodology for including quantifiable environmental costs in planning. These are: 1) including the cost of meeting existing environmental regulations into the capital and operating costs of conservation and generating resources; 2) where possible, quantifying the potential costs of new regulations under consideration; 3) accounting for the environmental benefits that may be associated with specific resources, usually associated with improved efficiency, and 4) recognizing additional environmental effects that may remain after compliance with existing regulations even though they may not be readily quantifiable.

## *Cost of Existing Regulations*

The Council's planning assumes that all new generating resource alternatives meet existing environmental regulations. The costs of emissions reduction equipment and operations are included in resource costs, state limits on new power plant emissions are enforced, and various siting limitations, such as rivers and streams that fall in protected areas, are recognized. The Council also includes the cost of meeting existing regulations affecting conservation measures, such as PCB disposal from replacement of transformers, and mercury disposal from replacement of linear fluorescent lamps. In addition, hydro operations consistent with the Council's Fish and Wildlife Program are considered a constraint on the operation of the hydropower system. These reflect the cost of policy choices that have already been made.

## *Potential Cost of New Regulations*

Some environmental policies are still evolving or are being reconsidered. In some cases these are certain enough to include the costs in the plan directly. For example, mercury emissions limits have been assumed to become requirements and the cost added to new coal plants costs.[2] Similarly, the cost of recycling compact fluorescent lamps which contain trace amounts of mercury has been included in this measure's cost.

In other cases increased regulation is likely, but details have not been settled. In the Sixth Power Plan, this is the case with carbon control policies. While many states have renewable portfolio standards and limits on emissions from new power plants, carbon pricing policy is being actively discussed but is still highly uncertain in terms of its level and structure. Renewable portfolio standards and new plant emissions limits are included in the Council's analysis as existing regulations. However, carbon pricing policy is quantified as an uncertainty. Several scenarios explore the likely effects of different levels of carbon pricing on resource costs and choices.

## *Consideration of Environmental Benefits*

For some resources, primarily efficiency improvements, there are associated environmental benefits. Where quantifiable, the Council counts these as a cost savings. For example, high efficiency clothes washers not only save energy, they also reduce water and detergent use. These are treated as positive environmental externalities in the Council's planning. The direct environmental benefit of reduced electricity use is not credited as an environmental benefit against the cost of conservation, but is instead reflected as reduced costs of avoided generation technologies.

## *Residual Environmental Costs*

The regulations set through policy making are assumed to be acceptable levels of mitigation by society as discussed above. Also, where serious policy discussions are underway to change regulations, the Council attempts to reflect the potential changes in its planning. However, regulations seldom completely eliminate the environmental effects of electricity production and use. To the extent possible, the effects of residual emissions or other environmental effects should be considered in resource decisions.

In some cases, the Council has included unregulated mitigation requirements and cost into its planning. For example, the Council takes into account concerns about indoor air quality in homes that are highly sealed and insulated. In its first power plan and all subsequent plans the Council's Model Conservation Standards required that heat exchangers be installed to provide adequate ventilation in such homes to prevent indoor air quality problems. Ventilation

[2] At issue here are the costs of existing coal units w/o flue gas desulphurization (Boardman is the only remaining regional example). The Council assumed costs regarding mercury abatement based on the Clean Air Mercury Rule (CAMR), issued by the Bush EPA in March 2005. CAMR established Hg emission limits for new coal units but exempted existing units. For most new pulverized coal-fired units, the CAMR limits could be achieved through "co-benefit" Hg removal (~90 percent) by required sulfur and particulate control equipment. Activated carbon filters would be required for IGCC plant compliance. (So in practice CAMR represented "business as usual" for most new and existing pulverized coal units though touted as new mercury control regulation.) Our new coal-fired power plant costs are consistent with CAMR (activated carbon filters for IGCC units; no equipment in addition to FGD & particulate control for new PC units, no new costs for existing units w/o FGD (i.e., Boardman)). However, CAMR was challenged in court and vacated by the DC Circuit Court in February 2009. The EPA withdrew its petition for review and is now developing new standards in accordance with the DC circuit court opinion. The new standards will likely require compliance by existing as well as new plants.

requirements are now included in building codes. Other potential problems of a similar nature should be considered and mitigated where cost-effective.

The Council has not usually considered the effects of residual emissions to be reliably quantifiable. However, there have been extensive efforts to quantify such environmental costs, many undertaken for the purpose of balancing the cost of mitigation and the cost of residual damages. A recent example is from the National Research Council.[3] Other examples include USDOE/Commission of European Communities (1992)[4] and European Commission (1995)[5]. The Council methodology recognizes such effects and acknowledges these costs in evaluating resources, but in an unquantified manner. Bonneville, in making resource decisions, should list residual environmental effects and consider the possible costs when considering alternative resource choices. The magnitude of the costs should be considered based on credible literature such as the National Research Council and the others referenced, but this methodology recognizes that the residual environmental costs related to a particular resource very often cannot be explicitly calculated.

[3] "The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use." The National Academies Press. 2009. http://www.nap.edu/catalog.php?record_id=12794#description

[4] U.S. Department of Energy and the Commission of European Communities. *U.S. - EC Fuel Cycle Study ORNL* (Reports No. 1 through 8). 1992 through 1998.

[5] European Commission. *Externalities of Energy EUR 16520-25* (Volumes 1 through 6). 1995.