Northwest Power and Conservation Council

DRAFT FUEL PRICES FOR THE SIXTH POWER PLAN

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NORTHWEST VI POWER PLAN

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Draft Fuel Prices for Sixth Power Plan

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 during later in 2008, but remain high by standards of the 1980s and 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 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 liquified 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 signficant 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 Council is considering adding additional analysis of coal price risk for the Sixth Power Plan.

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 storage levels. The forecasts discuss only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis.

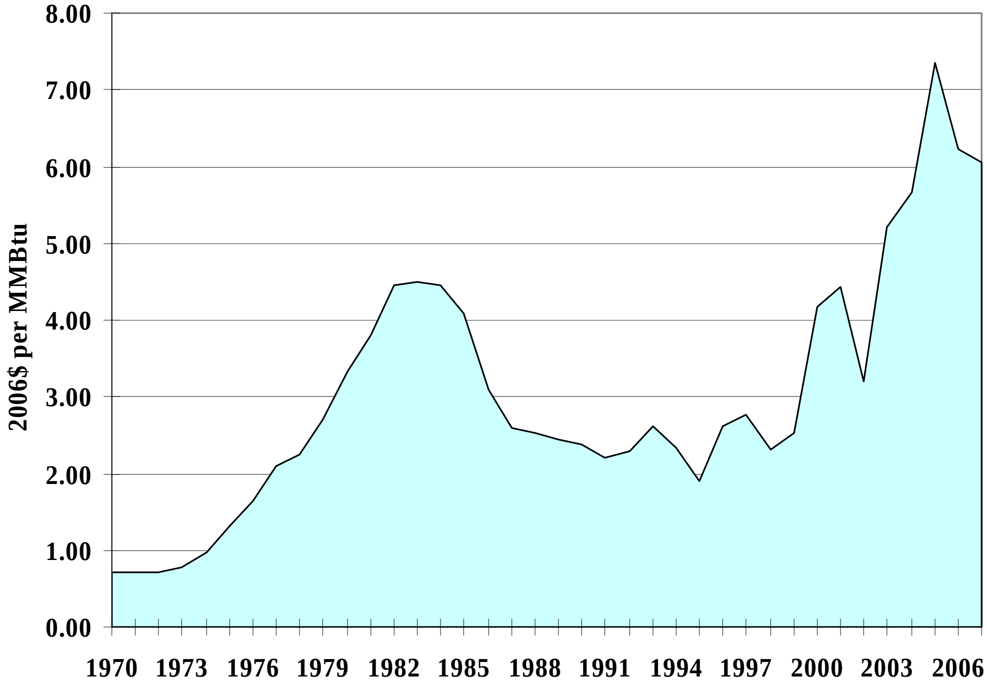
There are additional uncertainties to the cost of fuel from the effects of climate policies, such as CO2 costs from taxes or a cap and trade structure. These additional costs are explicitly treated in the Council's portfolio model and affect the cost of using various fuels, but are not a part of the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

NATURAL GAS

Background

The Council's forecast of natural gas prices starts with a national level commodity price, the average natural gas wellhead price of the lower-48 states. A look at the past behavior of these prices gives perspective for the forecasts. Figure 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 2007 the wellhead price of natural gas averaged $6, nearly three 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 1: Historical Wellhead Natural Gas Price



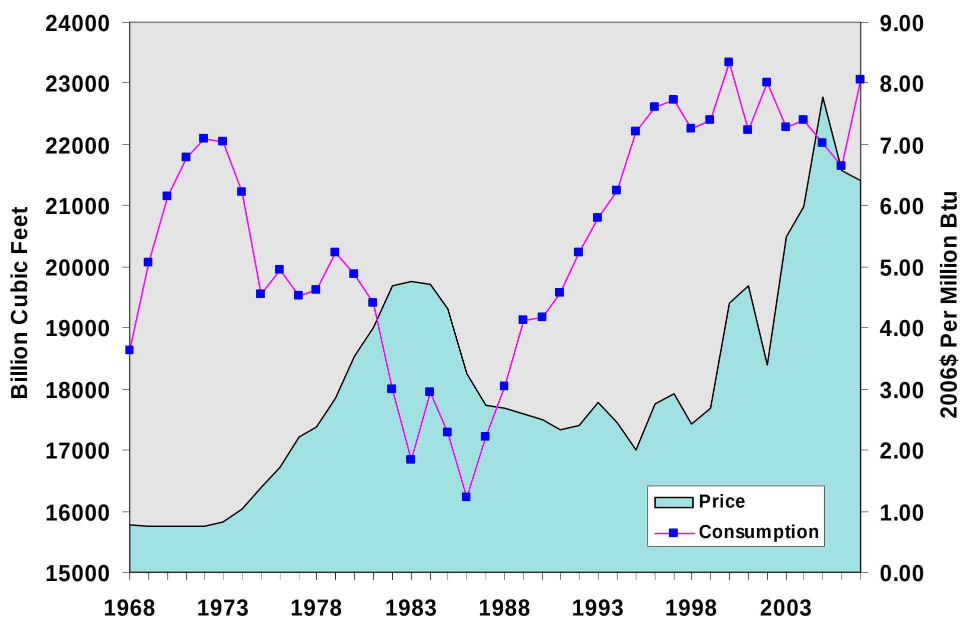
The Council's forecast of natural gas prices is informed by national level forecasts of prices from other organizations that specialize in analysis of fuel commodity markets. Such forecasts rely on estimates of the fundamentals of supply, demand, and the transportation capacity to move natural gas from 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 2 shows these patterns. Also evident in Figure 2 is the moderating effect of recent natural gas price increases on natural gas use since 2000.

Figure 2: Historical Natural Gas Prices and Consumption



Price Forecasts

U.S. Natural Gas Commodity Prices

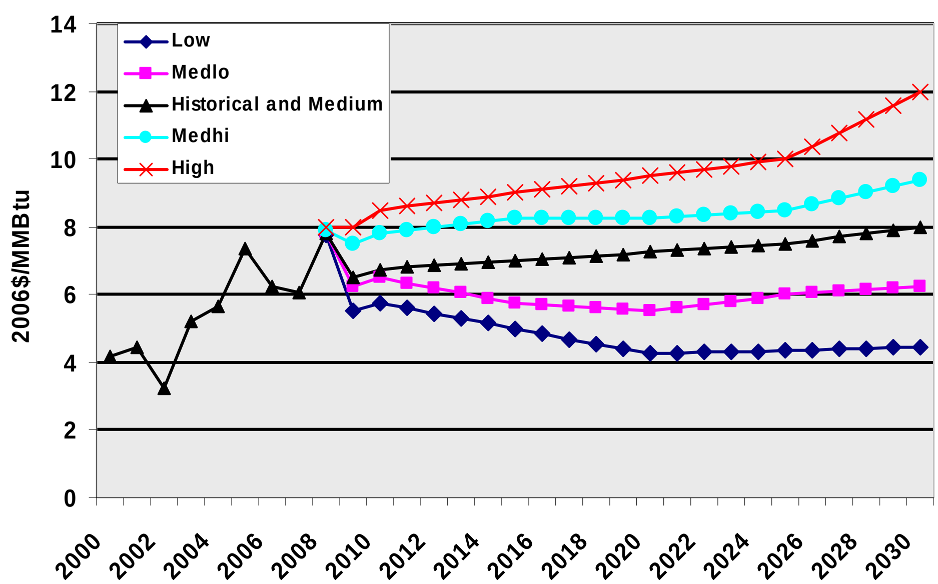
There are several characteristics of the recent price increases that have implications for the future long-term trends in natural gas price. On the supply side, it has become clear that conventional natural gas supplies are increasingly difficult to expand. This does not mean that supply will not be 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. It is estimated that such nonconventional supplies of natural gas now account for half of U.S. natural gas production. 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 $7 and $8 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 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. 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 high point in a commodity cycle, most of the forecast range includes decreases from recent levels. However, trend prices do not fall back to the $2.30 natural gas prices of the 1990s, even in the lowest price forecast.

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

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



The medium case forecast shows prices declining to $7 (in 2006 prices) by 2015, and then trending upward slowly, reaching $8.00 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 until 2025 and then increase to nearly $12 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 Portfolio Model. Table 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 1.

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

	Low	Medium Low	Medium	Medium High	High
2007			6.06		
2010	5.75	6.50	6.75	7.80	8.50
2015	5.00	5.75	7.00	8.25	9.00
2020	4.25	5.50	7.25	8.25	9.50
2025	4.35	6.00	7.50	8.50	10.00
2030	4.45	6.25	8.00	9.40	12.00
Growth Rates					
2007 - 15	-2.36%	-0.64%	1.83%	3.94%	5.08%
2007 - 30	-1.33%	0.14%	1.22%	1.93%	2.89%

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 4 illustrates the Northwest's natural gas delivery system.

Figure 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 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 2 shows the values for selected years. Figure 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 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 5: Medium Case Natural Gas Price Forecasts at Northwest Hubs

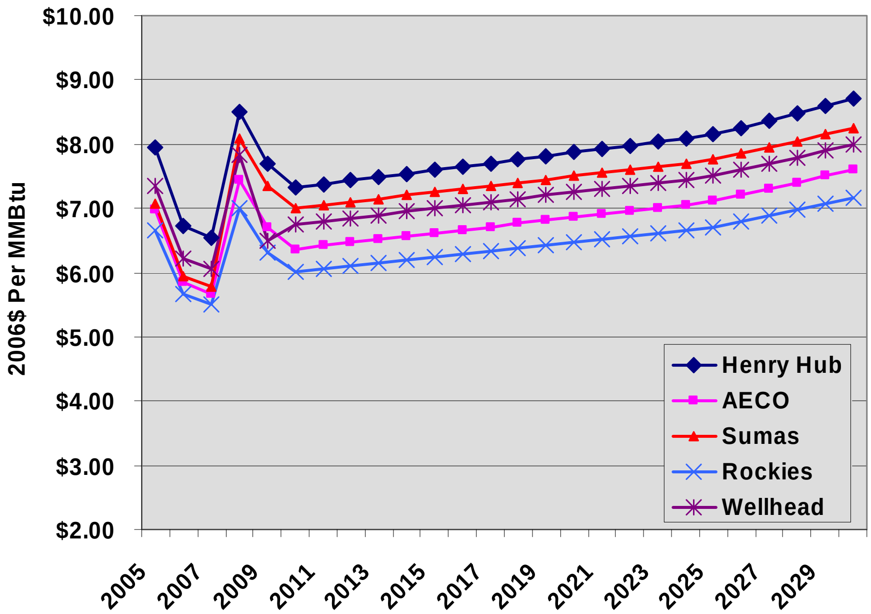
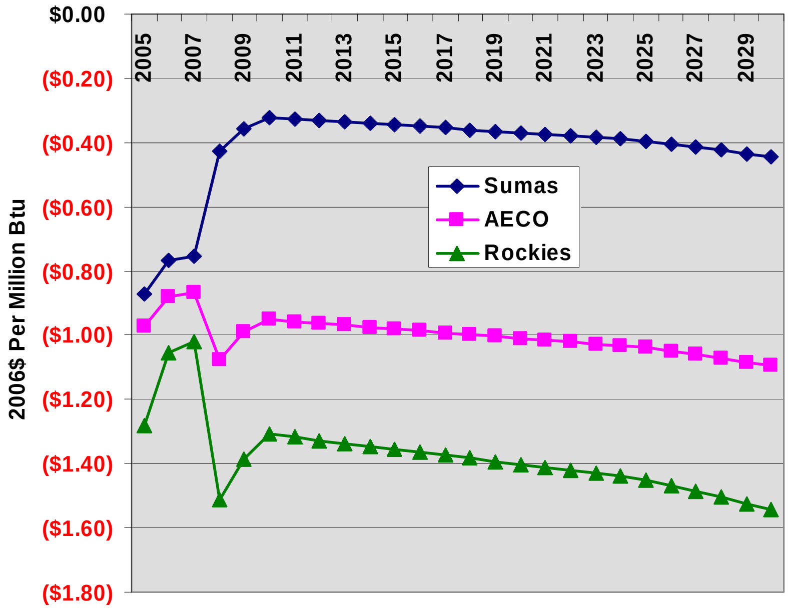


Table 2: Medium Case Prices Natural Gas Price Forecasts at Northwest Hubs (2006 Dollars Per Million Btu)

	Wellhead	Henry Hub	AECO	Sumas	Rockies
2007	$6.06	$6.53	5.67	$5.78	$5.51
2010	$6.75	$7.32	6.37	$7.00	$6.01
2015	$7.00	$7.60	6.62	$7.25	$6.24
2020	$7.25	$7.87	6.86	$7.50	$6.47
2025	$7.50	$8.15	7.11	$7.75	$6.70
2030	$8.00	$8.70	7.60	$8.26	$7.16
Growth Rates					
2007 - 15	1.83%	1.90%	1.95%	2.87%	1.56%
2007 - 30	1.22%	1.25%	1.29%	1.56%	1.14%

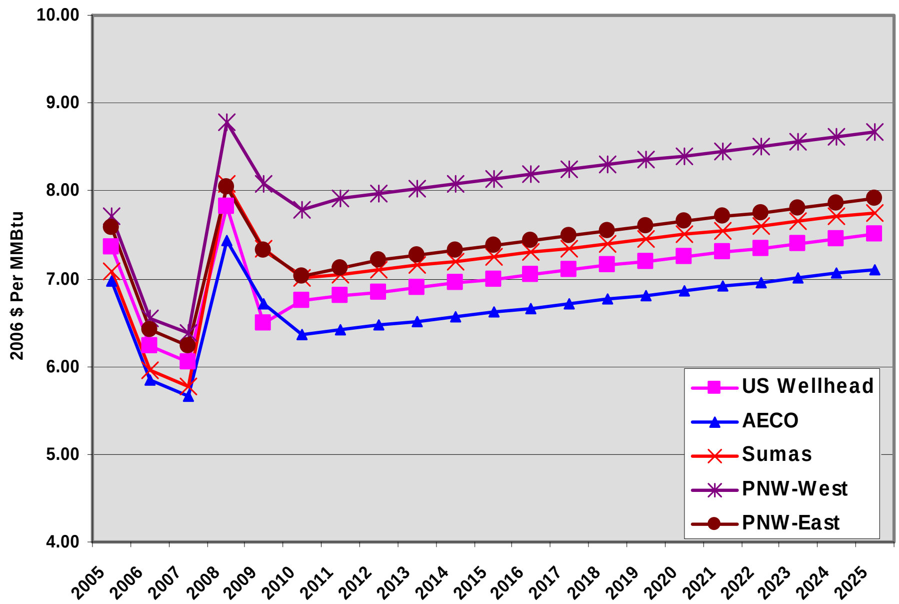
Figure 6: Medium Case Basis Differentials From Henry Hub Prices



Forecasts of natural gas delivered to specific parts of the region 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 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 7: Incremental Natural Gas Prices Delivered to Regional Generation Facilities



OIL

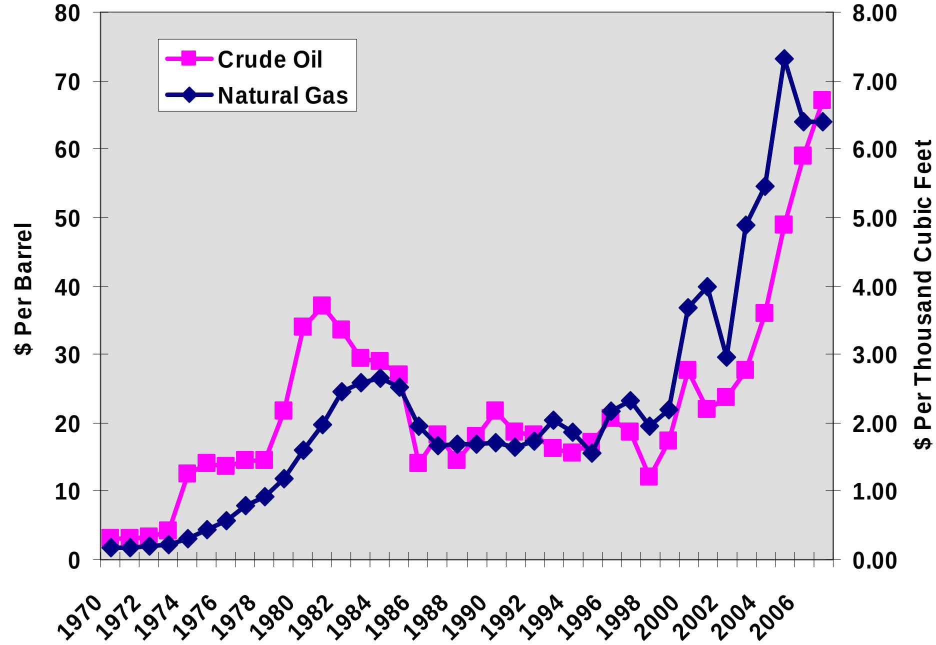
Background

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 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. Prices have recently fallen to below $50 a barrel, but are still well above historical levels.

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 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 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 $75 dollars per barrel (2006 dollars), somewhat 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 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 9: World Oil Prices: History and Forecast

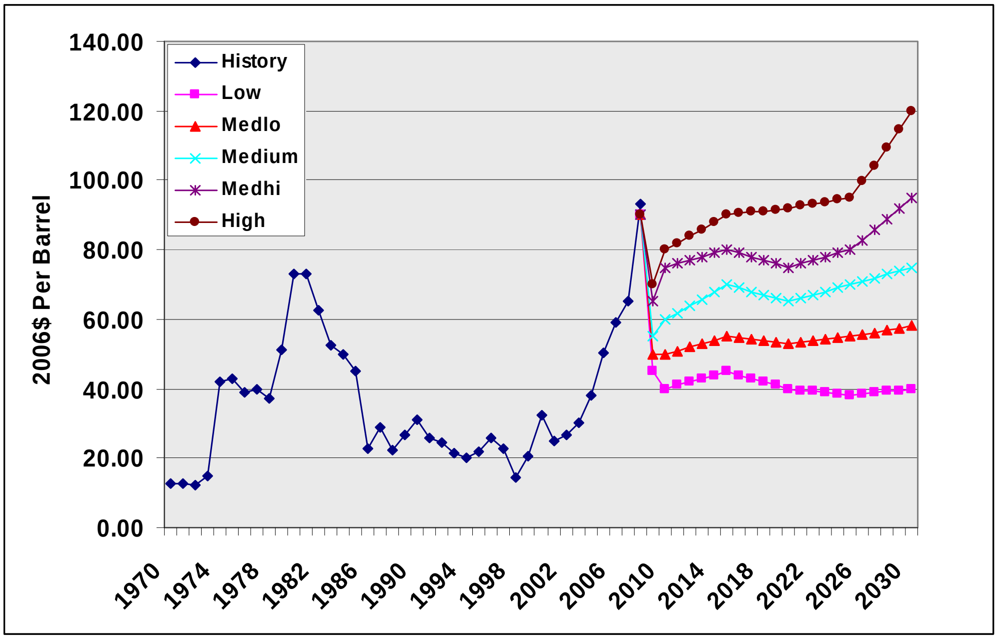
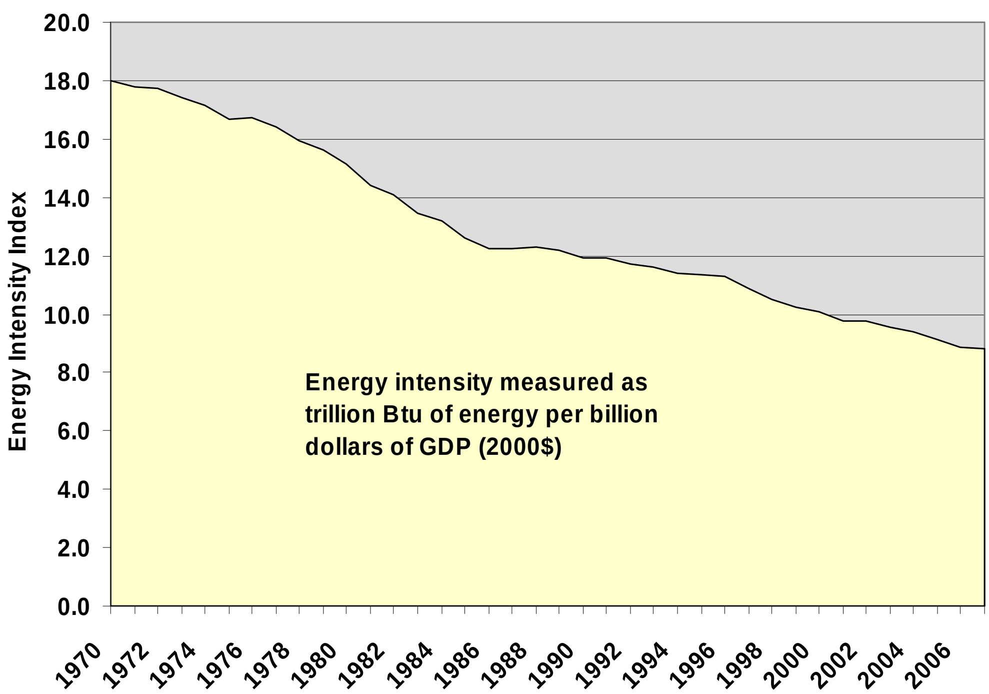


Figure 10: Total U.S. Energy Use Per Dollar of Gross Domestic Product



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 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 3: World Oil Price Forecast Range (2006 Dollar Per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007			65.29		
2008			90.00		
2010	40.00	50.00	60.00	75.00	80.00
2015	45.00	55.00	70.00	80.00	90.00
2020	40.00	53.00	65.00	75.00	92.00
2025	38.00	55.00	70.00	80.00	95.00
2030	40.00	58.00	75.00	95.00	120.00
Growth Rates					
2007 - 15	-4.54%	-2.12%	0.88%	2.57%	4.09%
2007 - 30	-2.11%	-0.51%	0.60%	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.[1] 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.

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

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 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.

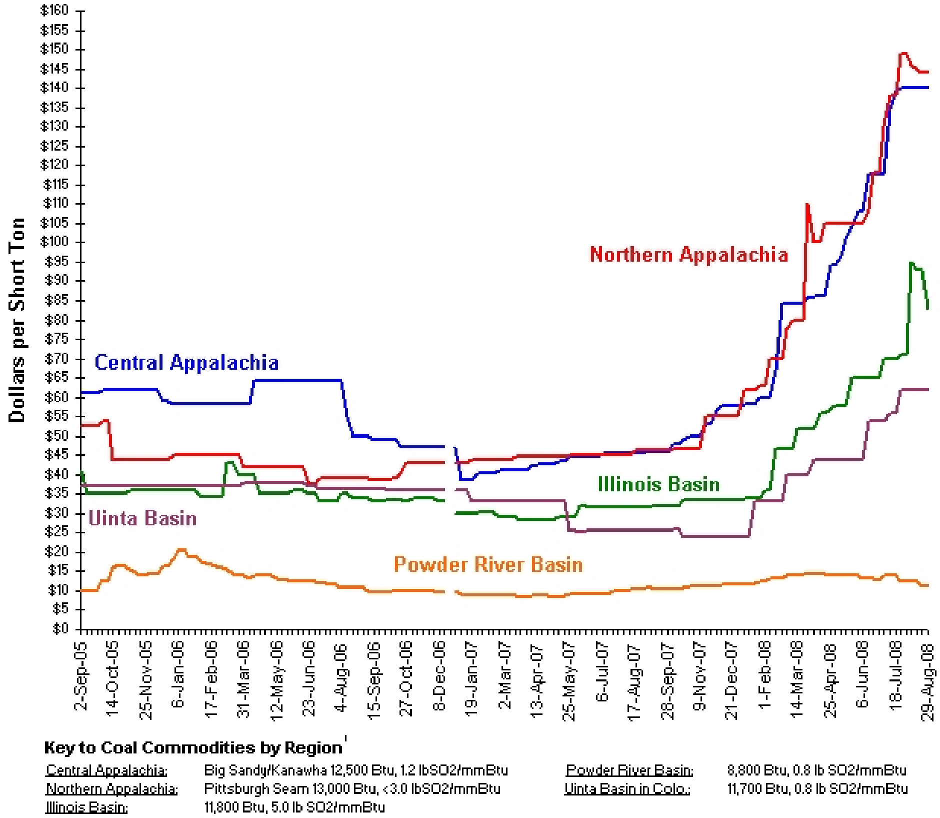
Western coal production in 2007 was 612 million short tons, with 74 percent of that production coming from Wyoming (454 million short tons). The second largest state producer was Montana at 43 million tons. Colorado, New Mexico, North Dakota and Utah produced between 24 and 36 million short tons each, and Arizona produced about 8 million short tons.[2]

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 11 shows historical coal cost from various supply areas. Additional forecast details are shown in the appendix tables.

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

Figure 11: Coal Price Trends from Major Supply Areas



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

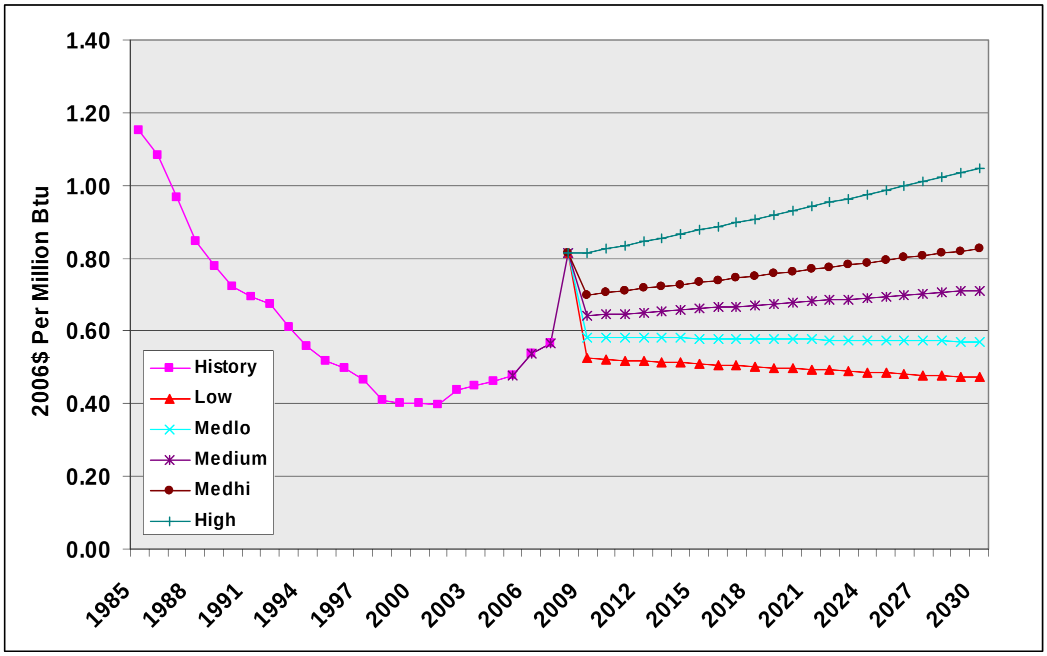
Coal Price Forecast

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 4 demonstrates these assumptions. Figure 12 shows the resulting forecast range.

Table 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 12: Range of Powder River Basin Coal Price Forecasts

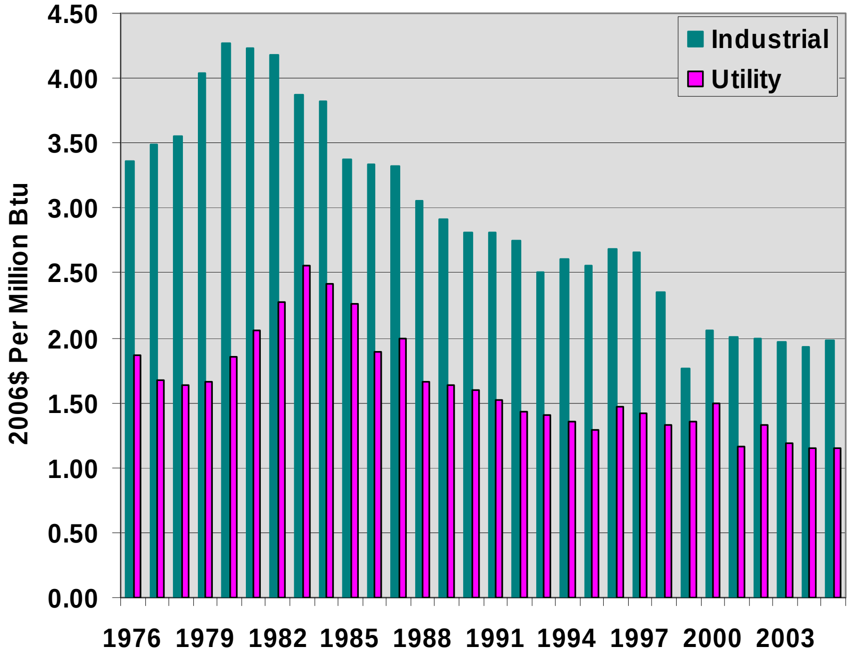


The price of coal delivered to northwest electric generators and industries is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from mine-mouth costs due to long-term coal supply contracts. Figure 13 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 2005.[3] 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 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.

[3] U.S. Energy Information Administration

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



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Appendix A: Medium Case Fuel Price Forecast Tables

Table A-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	8.51	7.44	8.09	8.77	8.04
2009	7.70	6.71	7.34	8.07	7.33
2010	7.32	6.37	7.00	7.79	7.02
2011	7.38	6.42	7.05	7.91	7.12
2012	7.43	6.47	7.10	7.97	7.22
2013	7.48	6.52	7.15	8.03	7.27
2014	7.54	6.57	7.20	8.08	7.32
2015	7.60	6.62	7.25	8.14	7.37
2016	7.65	6.66	7.30	8.19	7.44
2017	7.71	6.71	7.35	8.24	7.49
2018	7.76	6.76	7.40	8.29	7.55
2019	7.82	6.81	7.45	8.35	7.60
2020	7.87	6.86	7.50	8.40	7.65
2021	7.93	6.91	7.55	8.46	7.70
2022	7.98	6.96	7.60	8.51	7.76
2023	8.04	7.01	7.65	8.56	7.81
2024	8.09	7.06	7.70	8.62	7.86
2025	8.15	7.11	7.75	8.67	7.91
2026	8.26	7.21	7.85	8.77	8.01
2027	8.36	7.30	7.95	8.88	8.11
2028	8.48	7.40	8.05	8.98	8.22
2029	8.59	7.50	8.15	9.09	8.32
2030	8.70	7.60	8.26	9.19	8.43

Table A-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	7.83	13.13	11.63	9.12	8.40
2009	6.50	11.80	10.30	8.19	7.67
2010	6.75	12.05	10.55	8.02	7.35
2011	6.80	12.10	10.60	8.07	7.43
2012	6.85	12.15	10.65	8.12	7.49
2013	6.90	12.20	10.70	8.18	7.55
2014	6.95	12.25	10.75	8.23	7.60
2015	7.00	12.30	10.80	8.28	7.65
2016	7.05	12.35	10.85	8.33	7.70
2017	7.10	12.40	10.90	8.38	7.75
2018	7.15	12.45	10.95	8.43	7.81
2019	7.20	12.50	11.00	8.48	7.86
2020	7.25	12.55	11.05	8.53	7.91
2021	7.30	12.60	11.10	8.58	7.96
2022	7.35	12.65	11.15	8.63	8.02
2023	7.40	12.70	11.20	8.68	8.07
2024	7.45	12.75	11.25	8.74	8.12
2025	7.50	12.80	11.30	8.79	8.17
2026	7.60	12.90	11.40	8.89	8.27
2027	7.70	13.00	11.50	8.99	8.37
2028	7.80	13.10	11.60	9.09	8.48
2029	7.90	13.20	11.70	9.19	8.58
2030	8.00	13.30	11.80	9.30	8.69

Table A-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	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2010	60.00	8.37	14.39	14.07	8.63	13.88	13.73	16.79	0.00	13.41
2011	61.88	8.64	14.75	14.43	8.91	14.24	14.09	17.15	0.00	13.77
2012	63.82	8.93	15.12	14.80	9.20	14.61	14.46	17.52	0.00	14.14
2013	65.81	9.22	15.51	15.18	9.49	15.00	14.85	17.90	0.00	14.52
2014	67.87	9.53	15.91	15.57	9.80	15.39	15.24	18.30	0.00	14.92
2015	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2016	68.97	9.69	16.12	15.78	9.96	15.61	15.45	18.51	0.00	15.13
2017	67.96	9.54	15.92	15.58	9.81	15.41	15.25	18.32	0.00	14.94
2018	66.96	9.39	15.73	15.39	9.66	15.22	15.06	18.12	0.00	14.74
2019	65.97	9.25	15.54	15.21	9.52	15.03	14.88	17.93	0.00	14.55
2020	65.00	9.10	15.35	15.02	9.37	14.84	14.69	17.75	0.00	14.37
2021	65.97	9.25	15.54	15.21	9.52	15.03	14.88	17.93	0.00	14.55
2022	66.96	9.39	15.73	15.39	9.66	15.22	15.06	18.12	0.00	14.74
2023	67.96	9.54	15.92	15.58	9.81	15.41	15.25	18.32	0.00	14.94
2024	68.97	9.69	16.12	15.78	9.96	15.61	15.45	18.51	0.00	15.13
2025	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2026	70.97	9.99	16.50	16.16	10.25	15.99	15.83	18.90	0.00	15.52
2027	71.96	10.13	16.69	16.34	10.40	16.18	16.02	19.08	0.00	15.71
2028	72.96	10.28	16.88	16.53	10.55	16.37	16.21	19.28	0.00	15.90
2029	73.97	10.43	17.08	16.73	10.70	16.57	16.40	19.47	0.00	16.09
2030	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29

Table A-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	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.64	1.98	1.45	1.28	0.94	0.90	0.81	0.73
2010	0.64	2.17	1.52	1.35	0.97	0.93	0.82	0.74
2011	0.65	2.15	1.52	1.34	0.97	0.93	0.83	0.74
2012	0.65	2.15	1.52	1.35	0.97	0.93	0.83	0.75
2013	0.65	2.16	1.52	1.35	0.97	0.94	0.83	0.75
2014	0.66	2.16	1.53	1.35	0.98	0.94	0.84	0.75
2015	0.66	2.16	1.53	1.36	0.98	0.94	0.84	0.76
2016	0.66	2.15	1.53	1.35	0.98	0.95	0.84	0.76
2017	0.67	2.15	1.53	1.36	0.99	0.95	0.84	0.76
2018	0.67	2.16	1.53	1.36	0.99	0.95	0.85	0.76
2019	0.67	2.16	1.54	1.36	0.99	0.96	0.85	0.77
2020	0.68	2.16	1.54	1.37	1.00	0.96	0.85	0.77
2021	0.68	2.18	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	1.56	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	1.39	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 B: Low Case Fuel Price Forecast Tables

Table B-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	8.46	7.39	8.04	8.72	7.99
2009	7.07	6.15	6.77	7.49	6.76
2010	6.22	5.38	6.00	6.77	6.02
2011	6.04	5.22	5.84	6.67	5.90
2012	5.87	5.07	5.68	6.53	5.80
2013	5.71	4.92	5.53	6.37	5.65
2014	5.55	4.78	5.38	6.22	5.50
2015	5.39	4.64	5.24	6.08	5.36
2016	5.21	4.48	5.08	5.91	5.21
2017	5.04	4.33	4.93	5.75	5.05
2018	4.88	4.18	4.77	5.60	4.92
2019	4.72	4.04	4.63	5.45	4.77
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	4.69	4.02	4.61	5.42	4.75
2027	4.72	4.04	4.63	5.44	4.76
2028	4.74	4.06	4.65	5.46	4.78
2029	4.76	4.08	4.67	5.48	4.80
2030	4.78	4.10	4.69	5.50	4.82

Table B-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	7.78	13.08	11.58	9.07	8.35
2009	5.50	10.80	9.30	7.49	7.09
2010	5.75	11.05	9.55	7.01	6.33
2011	5.59	10.90	9.39	6.85	6.20
2012	5.44	10.74	9.24	6.69	6.06
2013	5.29	10.59	9.09	6.54	5.91
2014	5.14	10.45	8.94	6.39	5.76
2015	5.00	10.30	8.80	6.24	5.61
2016	4.84	10.14	8.64	6.08	5.46
2017	4.69	9.99	8.49	5.92	5.30
2018	4.54	9.84	8.34	5.77	5.15
2019	4.39	9.69	8.19	5.62	5.00
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	4.37	9.67	8.17	5.60	4.98
2027	4.39	9.69	8.19	5.62	5.00
2028	4.41	9.71	8.21	5.64	5.02
2029	4.43	9.73	8.23	5.66	5.04
2030	4.45	9.75	8.25	5.68	5.06

Table B-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	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	45.00	6.15	11.51	11.22	6.42	11.00	10.87	13.90	0.00	10.52
2010	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56
2011	40.95	5.55	10.73	10.45	5.82	10.22	10.10	13.12	0.00	9.74
2012	41.93	5.70	10.92	10.64	5.96	10.41	10.28	13.31	0.00	9.93
2013	42.93	5.84	11.11	10.83	6.11	10.60	10.47	13.50	0.00	10.12
2014	43.95	6.00	11.31	11.02	6.26	10.80	10.67	13.70	0.00	10.32
2015	45.00	6.15	11.51	11.22	6.42	11.00	10.87	13.90	0.00	10.52
2016	43.95	6.00	11.31	11.02	6.26	10.80	10.67	13.70	0.00	10.32
2017	42.93	5.84	11.11	10.83	6.11	10.60	10.47	13.50	0.00	10.12
2018	41.93	5.70	10.92	10.64	5.96	10.41	10.28	13.31	0.00	9.93
2019	40.95	5.55	10.73	10.45	5.82	10.22	10.10	13.12	0.00	9.74
2020	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56
2021	39.59	5.35	10.47	10.20	5.62	9.96	9.84	12.86	0.00	9.48
2022	39.19	5.29	10.39	10.12	5.56	9.88	9.76	12.78	0.00	9.41
2023	38.79	5.23	10.31	10.04	5.50	9.80	9.68	12.71	0.00	9.33
2024	38.39	5.17	10.24	9.97	5.44	9.73	9.61	12.63	0.00	9.25
2025	38.00	5.12	10.16	9.89	5.38	9.65	9.53	12.56	0.00	9.18
2026	38.39	5.17	10.24	9.97	5.44	9.73	9.61	12.63	0.00	9.25
2027	38.79	5.23	10.31	10.04	5.50	9.80	9.68	12.71	0.00	9.33
2028	39.19	5.29	10.39	10.12	5.56	9.88	9.76	12.78	0.00	9.41
2029	39.59	5.35	10.47	10.20	5.62	9.96	9.84	12.86	0.00	9.48
2030	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56

Table B-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	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.52	1.83	1.31	1.15	0.81	0.78	0.69	0.61
2010	0.52	1.98	1.37	1.20	0.84	0.80	0.70	0.62
2011	0.52	2.02	1.39	1.21	0.84	0.80	0.70	0.61
2012	0.52	2.02	1.39	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	2.01	1.38	1.21	0.83	0.79	0.69	0.61
2015	0.51	2.01	1.38	1.20	0.83	0.79	0.69	0.60
2016	0.51	1.99	1.37	1.20	0.82	0.79	0.68	0.60
2017	0.50	1.99	1.37	1.19	0.82	0.78	0.68	0.60
2018	0.50	1.99	1.36	1.19	0.82	0.78	0.68	0.60
2019	0.50	1.98	1.36	1.19	0.82	0.78	0.68	0.59
2020	0.50	1.98	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	1.98	1.35	1.18	0.80	0.77	0.66	0.58
2025	0.48	1.97	1.35	1.18	0.80	0.77	0.66	0.58
2026	0.48	1.98	1.35	1.17	0.80	0.76	0.66	0.58
2027	0.48	1.97	1.35	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	1.97	1.34	1.17	0.79	0.76	0.65	0.57
2030	0.47	1.97	1.34	1.16	0.79	0.75	0.65	0.57

Appendix C: Medium-Low Case Fuel Price Forecast Tables

Table C-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	8.48	7.41	8.06	8.74	8.01
2009	7.53	6.56	7.19	7.92	7.18
2010	7.04	6.12	6.75	7.53	6.77
2011	6.87	5.97	6.59	7.44	6.65
2012	6.70	5.81	6.44	7.30	6.55
2013	6.54	5.67	6.29	7.14	6.40
2014	6.37	5.52	6.14	7.00	6.26
2015	6.22	5.38	6.00	6.85	6.11
2016	6.16	5.33	5.94	6.80	6.07
2017	6.11	5.28	5.89	6.75	6.02
2018	6.05	5.23	5.84	6.70	5.99
2019	6.00	5.18	5.79	6.65	5.94
2020	5.94	5.13	5.74	6.60	5.89
2021	6.05	5.23	5.84	6.70	5.99
2022	6.16	5.33	5.94	6.80	6.09
2023	6.27	5.42	6.04	6.90	6.19
2024	6.38	5.52	6.14	7.01	6.29
2025	6.49	5.63	6.25	7.11	6.40
2026	6.55	5.68	6.30	7.16	6.45
2027	6.60	5.72	6.35	7.22	6.50
2028	6.66	5.77	6.40	7.27	6.55
2029	6.71	5.82	6.45	7.32	6.60
2030	6.77	5.87	6.50	7.37	6.65

Table C-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	7.80	13.10	11.60	9.09	8.37
2009	6.25	11.55	10.05	8.01	7.52
2010	6.50	11.80	10.30	7.77	7.10
2011	6.34	11.65	10.14	7.61	6.96
2012	6.19	11.49	9.99	7.45	6.82
2013	6.04	11.34	9.84	7.30	6.67
2014	5.89	11.20	9.69	7.15	6.52
2015	5.75	11.05	9.55	7.01	6.38
2016	5.70	11.00	9.50	6.95	6.33
2017	5.65	10.95	9.45	6.90	6.28
2018	5.60	10.90	9.40	6.85	6.23
2019	5.55	10.85	9.35	6.80	6.18
2020	5.50	10.80	9.30	6.75	6.13
2021	5.60	10.90	9.40	6.85	6.23
2022	5.69	11.00	9.50	6.95	6.33
2023	5.79	11.10	9.60	7.05	6.43
2024	5.90	11.20	9.70	7.16	6.54
2025	6.00	11.30	9.80	7.26	6.64
2026	6.05	11.35	9.85	7.31	6.69
2027	6.10	11.40	9.90	7.36	6.74
2028	6.15	11.45	9.95	7.41	6.79
2029	6.20	11.50	10.00	7.46	6.85
2030	6.25	11.55	10.05	7.52	6.90

Table C-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	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	50.00	6.89	12.47	12.17	7.16	11.96	11.82	14.86	0.00	11.48
2010	50.00	6.89	12.47	12.17	7.16	11.96	11.82	14.86	0.00	11.48
2011	50.96	7.03	12.65	12.36	7.30	12.14	12.01	15.05	0.00	11.67
2012	51.94	7.18	12.84	12.54	7.44	12.33	12.20	15.24	0.00	11.86
2013	52.94	7.32	13.03	12.73	7.59	12.52	12.39	15.43	0.00	12.05
2014	53.96	7.47	13.23	12.92	7.74	12.72	12.58	15.62	0.00	12.25
2015	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2016	54.59	7.57	13.35	13.05	7.84	12.84	12.70	15.75	0.00	12.37
2017	54.19	7.51	13.27	12.97	7.78	12.76	12.63	15.67	0.00	12.29
2018	53.79	7.45	13.20	12.89	7.72	12.69	12.55	15.59	0.00	12.21
2019	53.39	7.39	13.12	12.82	7.66	12.61	12.47	15.52	0.00	12.14
2020	53.00	7.33	13.05	12.74	7.60	12.53	12.40	15.44	0.00	12.06
2021	53.39	7.39	13.12	12.82	7.66	12.61	12.47	15.52	0.00	12.14
2022	53.79	7.45	13.20	12.89	7.72	12.69	12.55	15.59	0.00	12.21
2023	54.19	7.51	13.27	12.97	7.78	12.76	12.63	15.67	0.00	12.29
2024	54.59	7.57	13.35	13.05	7.84	12.84	12.70	15.75	0.00	12.37
2025	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2026	55.59	7.71	13.54	13.23	7.98	13.03	12.89	15.94	0.00	12.56
2027	56.18	7.80	13.66	13.35	8.07	13.15	13.01	16.05	0.00	12.67
2028	56.78	7.89	13.77	13.46	8.16	13.26	13.12	16.17	0.00	12.79
2029	57.39	7.98	13.89	13.58	8.25	13.38	13.24	16.28	0.00	12.90
2030	58.00	8.07	14.01	13.69	8.34	13.50	13.35	16.40	0.00	13.02

Table C-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	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.58	1.91	1.38	1.22	0.88	0.84	0.75	0.67
2010	0.58	2.07	1.45	1.27	0.90	0.86	0.76	0.68
2011	0.58	2.08	1.45	1.28	0.90	0.86	0.76	0.68
2012	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.68
2013	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.68
2014	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.67
2015	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.67
2016	0.58	2.07	1.44	1.27	0.90	0.86	0.76	0.67
2017	0.58	2.07	1.44	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	0.89	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	0.86	0.75	0.67
2027	0.57	2.07	1.44	1.27	0.89	0.85	0.75	0.67
2028	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67
2029	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67
2030	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67

Appendix D: Medium-High Case Fuel Price Forecast Tables

Table D-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	8.59	7.51	8.16	8.85	8.11
2009	8.34	7.28	7.92	8.66	7.91
2010	8.48	7.41	8.06	8.87	8.08
2011	8.58	7.49	8.14	9.03	8.21
2012	8.67	7.58	8.23	9.13	8.36
2013	8.77	7.67	8.32	9.23	8.45
2014	8.87	7.76	8.41	9.32	8.54
2015	8.98	7.85	8.51	9.42	8.63
2016	8.98	7.85	8.51	9.43	8.65
2017	8.98	7.85	8.51	9.43	8.65
2018	8.98	7.85	8.51	9.43	8.66
2019	8.98	7.85	8.51	9.44	8.66
2020	8.98	7.85	8.51	9.44	8.66
2021	9.03	7.90	8.56	9.49	8.71
2022	9.09	7.95	8.61	9.55	8.77
2023	9.14	8.00	8.66	9.60	8.82
2024	9.20	8.05	8.71	9.66	8.87
2025	9.25	8.10	8.76	9.71	8.93
2026	9.44	8.27	8.93	9.90	9.11
2027	9.64	8.44	9.11	10.08	9.29
2028	9.84	8.62	9.29	10.27	9.47
2029	10.04	8.80	9.47	10.46	9.66
2030	10.25	8.99	9.66	10.66	9.85

Table D-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	7.90	13.20	11.70	9.19	8.47
2009	7.50	12.80	11.30	8.91	8.26
2010	7.80	13.10	11.60	9.09	8.42
2011	7.89	13.19	11.69	9.18	8.53
2012	7.98	13.28	11.78	9.27	8.64
2013	8.07	13.37	11.87	9.36	8.73
2014	8.16	13.46	11.96	9.46	8.83
2015	8.25	13.55	12.05	9.55	8.92
2016	8.25	13.55	12.05	9.55	8.93
2017	8.25	13.55	12.05	9.55	8.93
2018	8.25	13.55	12.05	9.55	8.93
2019	8.25	13.55	12.05	9.55	8.93
2020	8.25	13.55	12.05	9.55	8.93
2021	8.30	13.60	12.10	9.60	8.98
2022	8.35	13.65	12.15	9.65	9.04
2023	8.40	13.70	12.20	9.70	9.09
2024	8.45	13.75	12.25	9.75	9.14
2025	8.50	13.80	12.30	9.81	9.20
2026	8.67	13.98	12.47	9.98	9.37
2027	8.85	14.15	12.65	10.16	9.55
2028	9.03	14.33	12.83	10.34	9.74
2029	9.21	14.52	13.01	10.53	9.93
2030	9.40	14.70	13.20	10.72	10.12

Table D-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	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	65.00	9.10	15.35	15.02	9.37	14.84	14.69	17.75	0.00	14.37
2010	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29
2011	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2012	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2013	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2014	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2015	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2016	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2017	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2018	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2019	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2020	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29
2021	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2022	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2023	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2024	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2025	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2026	82.80	11.73	18.77	18.40	12.00	18.26	18.09	21.17	0.00	17.79
2027	85.69	12.16	19.33	18.95	12.43	18.82	18.64	21.73	0.00	18.35
2028	88.69	12.60	19.91	19.52	12.87	19.40	19.22	22.30	0.00	18.92
2029	91.79	13.06	20.50	20.11	13.33	19.99	19.81	22.90	0.00	19.52
2030	95.00	13.53	21.12	20.72	13.80	20.61	20.42	23.52	0.00	20.14

Table D-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	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.70	2.08	1.52	1.36	1.00	0.97	0.87	0.79
2010	0.70	2.25	1.59	1.41	1.03	0.99	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	2.22	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	2.23	1.60	1.43	1.06	1.02	0.92	0.83
2017	0.75	2.23	1.61	1.44	1.06	1.03	0.92	0.84
2018	0.75	2.24	1.62	1.44	1.07	1.03	0.93	0.85
2019	0.76	2.24	1.62	1.45	1.08	1.04	0.93	0.85
2020	0.76	2.25	1.63	1.45	1.08	1.04	0.94	0.86
2021	0.77	2.27	1.64	1.46	1.09	1.05	0.95	0.86
2022	0.78	2.27	1.64	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	2.29	1.66	1.49	1.11	1.08	0.97	0.89
2026	0.80	2.31	1.67	1.50	1.12	1.08	0.98	0.90
2027	0.81	2.31	1.68	1.50	1.13	1.09	0.99	0.90
2028	0.81	2.32	1.69	1.51	1.13	1.10	0.99	0.91
2029	0.82	2.33	1.69	1.52	1.14	1.10	1.00	0.92
2030	0.83	2.33	1.70	1.52	1.15	1.11	1.01	0.92

Appendix E: High Case Fuel Price Forecast Tables

Table E-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	8.70	7.60	8.26	8.95	8.22
2009	8.69	7.59	8.24	8.99	8.23
2010	9.25	8.10	8.76	9.59	8.79
2011	9.36	8.20	8.86	9.75	8.93
2012	9.47	8.29	8.96	9.87	9.08
2013	9.58	8.39	9.06	9.98	9.18
2014	9.69	8.49	9.16	10.08	9.28
2015	9.80	8.59	9.26	10.19	9.39
2016	9.91	8.69	9.36	10.30	9.50
2017	10.02	8.79	9.46	10.41	9.60
2018	10.13	8.89	9.56	10.51	9.71
2019	10.24	8.99	9.66	10.62	9.82
2020	10.36	9.09	9.76	10.73	9.92
2021	10.46	9.18	9.86	10.84	10.02
2022	10.57	9.28	9.96	10.95	10.13
2023	10.68	9.38	10.06	11.05	10.23
2024	10.79	9.48	10.16	11.16	10.34
2025	10.91	9.58	10.27	11.27	10.45
2026	11.32	9.95	10.64	11.66	10.82
2027	11.74	10.33	11.03	12.06	11.22
2028	12.18	10.72	11.43	12.47	11.62
2029	12.64	11.13	11.84	12.90	12.05
2030	13.11	11.56	12.28	13.35	12.48

Table E-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	8.00	13.30	11.80	9.30	8.57
2009	8.00	13.30	11.80	9.29	8.58
2010	8.50	13.80	12.30	9.81	9.13
2011	8.60	13.90	12.40	9.90	9.25
2012	8.70	14.00	12.50	10.01	9.37
2013	8.80	14.10	12.60	10.11	9.48
2014	8.90	14.20	12.70	10.21	9.58
2015	9.00	14.30	12.80	10.31	9.68
2016	9.10	14.40	12.90	10.41	9.79
2017	9.20	14.50	13.00	10.51	9.89
2018	9.30	14.60	13.10	10.62	10.00
2019	9.40	14.70	13.20	10.72	10.10
2020	9.50	14.80	13.30	10.82	10.21
2021	9.60	14.90	13.40	10.92	10.31
2022	9.70	15.00	13.50	11.02	10.41
2023	9.80	15.10	13.60	11.13	10.52
2024	9.90	15.20	13.70	11.23	10.62
2025	10.00	15.30	13.80	11.33	10.73
2026	10.37	15.68	14.17	11.71	11.11
2027	10.76	16.06	14.56	12.10	11.50
2028	11.16	16.46	14.96	12.51	11.91
2029	11.57	16.87	15.37	12.93	12.33
2030	12.00	17.30	15.80	13.37	12.77

Table E-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	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2010	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2011	81.91	11.60	18.60	18.23	11.87	18.09	17.92	21.00	0.00	17.62
2012	83.86	11.89	18.98	18.60	12.16	18.47	18.29	21.37	0.00	17.99
2013	85.86	12.18	19.36	18.98	12.45	18.85	18.67	21.76	0.00	18.38
2014	87.90	12.49	19.76	19.37	12.75	19.25	19.07	22.15	0.00	18.77
2015	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2016	90.40	12.85	20.24	19.84	13.12	19.73	19.54	22.63	0.00	19.25
2017	90.79	12.91	20.31	19.92	13.18	19.80	19.62	22.71	0.00	19.33
2018	91.19	12.97	20.39	20.00	13.24	19.88	19.69	22.78	0.00	19.40
2019	91.60	13.03	20.47	20.07	13.30	19.96	19.77	22.86	0.00	19.48
2020	92.00	13.09	20.54	20.15	13.36	20.03	19.85	22.94	0.00	19.56
2021	92.59	13.18	20.66	20.26	13.45	20.15	19.96	23.05	0.00	19.67
2022	93.19	13.27	20.77	20.37	13.53	20.26	20.08	23.17	0.00	19.79
2023	93.79	13.36	20.89	20.49	13.62	20.38	20.19	23.28	0.00	19.90
2024	94.39	13.44	21.00	20.60	13.71	20.49	20.31	23.40	0.00	20.02
2025	95.00	13.53	21.12	20.72	13.80	20.61	20.42	23.52	0.00	20.14
2026	99.54	14.21	21.99	21.58	14.47	21.48	21.29	24.39	0.00	21.01
2027	104.31	14.91	22.91	22.49	15.18	22.40	22.20	25.30	0.00	21.93
2028	109.29	15.65	23.87	23.43	15.91	23.36	23.15	26.26	0.00	22.88
2029	114.52	16.42	24.87	24.43	16.69	24.36	24.15	27.27	0.00	23.89
2030	120.00	17.23	25.93	25.47	17.49	25.42	25.20	28.32	0.00	24.94

Table E-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	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.82	2.21	1.65	1.48	1.12	1.09	0.99	0.91
2010	0.83	2.37	1.71	1.53	1.15	1.11	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	2.38	1.75	1.58	1.21	1.17	1.06	0.98
2017	0.90	2.39	1.76	1.59	1.22	1.18	1.08	0.99
2018	0.91	2.40	1.78	1.60	1.23	1.19	1.09	1.00
2019	0.92	2.41	1.79	1.61	1.24	1.20	1.10	1.01
2020	0.93	2.42	1.80	1.62	1.25	1.21	1.11	1.03
2021	0.94	2.44	1.81	1.63	1.26	1.22	1.12	1.04
2022	0.95	2.45	1.82	1.65	1.27	1.23	1.13	1.05
2023	0.96	2.46	1.83	1.66	1.28	1.25	1.14	1.06
2024	0.98	2.47	1.84	1.67	1.30	1.26	1.15	1.07
2025	0.99	2.48	1.85	1.68	1.31	1.27	1.17	1.08
2026	1.00	2.51	1.87	1.70	1.32	1.28	1.18	1.09
2027	1.01	2.53	1.89	1.71	1.33	1.30	1.19	1.11
2028	1.02	2.54	1.90	1.72	1.35	1.31	1.20	1.12
2029	1.04	2.55	1.91	1.73	1.36	1.32	1.22	1.13
2030	1.05	2.56	1.92	1.75	1.37	1.33	1.23	1.14

Appendix F: Fuel Price Forecasting Model

INTRODUCTION

This paper describes the fuel price forecasting model that is used for the Council's 6th power plan. The model consists of several worksheets linked together in an EXCEL "workbook". The Excel model is in Q:\TM\FUEL\MODF\FUELMOD7(2) for the draft forecasts in December 2008.

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 Develop.xls" and then copied into the fuel price model. WOPFC, NGFC, and COALFC are tabs in the FUELMOD7(1) 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), 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) 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) 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), which is reproduced as Attachment 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 comverted 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 reestimated by Chris Collier in the summer of 2008.[1] The original equations were estimated for the Fifth Power Plan by Terry Morlan.[2] 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 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

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.

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

Table 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 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 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 3 shows the detailed estimation results.

Table 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:

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

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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 10

Table 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 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 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 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 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 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 14).

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

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

Table 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 14.

Tables 1a and 1b show the various transportation components, their column number in the COMPONENTS worksheet, and the current value or range of values in the model. Tables 2a and 2b 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 1a: 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	D42	1.99 %					
LDS Distribution							
Firm	F	$.20					
Interruptible Adj.	K	- $.05					
Firm Supply Premium	G	0%					

Table 2a: 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 1a.)

The formulas shown in Tables 1a and 1b 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 D42. 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 1a and 1b have already been converted to 2006 dollars.

The calculation of generator firm incremental natural gas prices is shown a different way in Tables 3a and 3b.

Table 1b: 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	D43	1.91 %					
LDS Distribution							
Firm	S	$.20					
Interruptible Adj.	X	- $.05					
Firm Supply Premium	T	0%					

Table 2b: 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 2b.)

Table 3a: Derivation of West-Side Firm Utility Gas Price
2006$/MMBtu

	Derivation of West-Side Firm Utility Gas Price									
Medium 11/21/2008	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 3b: 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 3a and 3b. 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 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[3]. 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 = $(.47H + .53L) - (C + .03C + 2.15)$

[3] 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.

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

Complex refinery

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

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

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

Solve for product prices:

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

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

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

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

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (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 1

--GUIDE TO FUEL PRICE FORECASTING MODEL PAGES

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DOC- -- -Describes files in the forecast model

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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 create 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.

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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.

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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

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NGWest Monthly----This tab creates monthly Hub prices from the U.S. wellhead price forecast using the equations in the Basis Equations tab.

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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.
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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 form 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).
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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.
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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.
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GASSUM- ---Summary table for gas price forecasts, linked to the individual
-- sector worksheets.
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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.
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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.
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COAL(Variable)----Same as COAL(Total) except that only inlcudes variable delivery costs.
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Tables--Develops tables to be included in forecast document appendices
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Graphs--Miscellaneous graphs to assess the forecast and describe results
--
NOTE: Columns with Red block at top need to be input during forecast period.

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