Staff Report to the Federal Energy Regulatory Commission on Northwest Power Markets in November and December 2000

February 1, 2001

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1. Overview and Summary

This report examines operating and market conditions in Northwest power markets during November and December 2000. It is an extension of an earlier report on bulk power markets in the West during summer 2000 and covers many of the same issues regarding high prices and their underlying causes.[1] The focus of this report is on rapidly increasing power prices during November and December, including a dramatic price spike in the second week of December. It provides further background on the Northwest in the context of the overall western power market described in the Western bulk power report, and examines the specific events and factors leading to increased prices during November and December.

The main observations from the study are summarized below:

- *November 2000 was the coldest November nationwide since 1911, with the coldest temperatures in the West and Northwest.* In early December, a massive arctic air mass descended on the Northwest region.

- *California was under frequent emergency conditions of varying severity during November and December, and was often unable to supply normal winter exports to the Northwest region*. The California emergency events are correlated with the high prices in the Northwest.

- *Low water levels, precipitation and stream flows limited the energy available from hydropower generation*. Especially low reservoir levels placed stringent limits on available water for power generation, in order to ensure supplies would be available later in the season during expected winter conditions. Low precipitation levels and diminishing stream flows in November and December led to lower forecasts of available water, and increased the impact on available water for power generation in December. As a result, the normal process of seasonal power exchange – sales from the Northwest to California in the summer in exchange for sales from the California to the Northwest in the winter – failed to materialize this year.

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[1] *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000.

- *Very little generation capacity was added in the Pacific Northwest (Washington and Oregon) or California during the 1990s*. This limited capacity, coupled with high demand and low energy supplies from hydropower, left the Northwest exposed to a power shortage when California experienced severe power emergencies. Additional generation is planned for the Northwest and California, but it is not projected to come on line until 2002 or 2003.

- *Environmental conditions limited the full use of power resources in the region*:

  - Air quality limits (on NOx) reached annual limits at a number of facilities in California and generation plants shut down, although some were later brought back on line after receiving waivers.

  - Minimum flow requirements at hydropower facilities needed to protect fish populations limited the ability to use water for power generation. Much of this water is "spilled" and not used for power generation. These limitations have a particularly large impact when reservoir levels and stream flows are low, by further reducing the water available for later generation needs.

- *Outages appear to have played a significant role in limiting availability of thermal capacity in the West*. Scheduled outages were delayed this fall, in part out of concerns that high temperatures would continue through October. As a result, more plants were out on scheduled maintenance when the cold temperatures hit. Forced outages at thermal plants, including older gas plants running at higher levels from May through September and plants shut down because of NOx limitations, contributed to the overall level of outages as well. Outages in California were high during the critical period of price spikes in early December and certainly put pressure on other resources to meet demand. However, our data on outages are very limited outside California and firm conclusions are difficult to draw.

- *Natural gas price increases, limits on pipeline capacity and storage levels contributed to the pressure on power prices.* Natural gas price and availability were affected by similar demand conditions, including requirements for heating and for electricity generation. Contributing factors included pipelines to California running full at capacity or limits on the capacity to take gas from the pipeline into the distribution systems, flow orders on some pipelines resulting from the flow levels, and low levels in California combined with high storage withdrawal rates.

- *Statistical analysis of available data confirms that much of the variation in power prices can be explained by operating conditions.* For example, a regression analysis indicates that around 94 percent of the power price variation can be explained by temperature, precipitation or stream flow levels, and tight supply and demand measured by the prevalence of emergency conditions in California.

In summary, the northwest power markets saw increased demand through the 1990s, without increased generation capacity in either the Pacific Northwest or in California. In November and December of 2000, the market was driven by extreme cold, high natural gas prices and low storage levels, and by low water, precipitation and stream flow levels. These conditions were made worse by an operating environment with a large number of outages and environmental constraints, and the general atmosphere of market uncertainty surrounding the extreme nature of these fundamental factors. In this environment, power prices rose to extremely high levels for much of the period, levels above short-term power production costs, and, if sustained, above long-term costs as well.

Northwest customers are not as exposed to these high prices as those in California. In California, some customers were directly exposed to the high spot market prices (San Diego) while others found their utilities at risk because of high power purchase costs. In the Northwest, customers are at much lower risk from the high prices, because a much greater proportion of the northwest load is protected through utility-owned generation or long-term contract, but some impact on customer rates is to be expected.

Section 2 provides a background showing how the Northwest fits into the context of the general western power markets and differentiates the northwest conditions from the remainder of the West. Section 3 summarizes the conditions leading up to November and December, and Section 4 analyzes the events of November and December.

2. Background

For purposes of this report, the Northwest power market will be viewed as the Northwest power area (NWPA) a subregion of the Western Systems Coordinating Council.[2] This area is shown in Figure 1. The Northwest power market is distinguished from other regional markets by the dominant role of hydropower resources and by substantial presence of federal and other public power entities, as depicted in Figure 2. From a planning and operational perspective, the major role of hydropower means that energy availability plays a central role, with generation capacity requirements highly dependent on water resource conditions and water use requirements outside the energy sector. In all regions, electricity demand is sensitive to long and short-term weather conditions. In the Northwest, both demand and supply conditions are highly dependent on weather.

This section surveys the patterns of generation resource use, loads and ownership in the Northwest and west since 1990. During this period, very little capacity was added in the Northwest, while loads were growing and generation from the aging resource base was utilized at an increasing rate. Areas outside the Pacific region (Washington, Oregon and California) supplied an increasing proportion of the generation needs in the West. At the same time, non-utility generation assumed a larger role, as overall utility purchases more than doubled and purchases from non-utility sources increased substantially. The remainder of this section provides background material on the evolution of these factors in the 1990s, setting the stage for the developments of summer and fall 2000.

Generation Capacity and Ownership

The Northwest currently has approximately 55,000 MW of winter generating capacity, about 65 percent hydropower. Very little capacity has been added since 1990: additions of 3,300 MW of capacity have been reduced by 2,530 MW of retirements. Additions to capacity have been primarily natural gas, but these have been offset by the retirement of nuclear capacity (see Table 1). Overall, operating capacity has increased by only 2 percent over a 10-year period.

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[2]Unless otherwise noted, only the U.S. portion of the area will be included. This area includes Washington, Oregon, Idaho and Utah, and portions of Montana, Wyoming, Nevada and California as shown in Figure 1.

Figure 1. Northwest Subregion of the WSCC

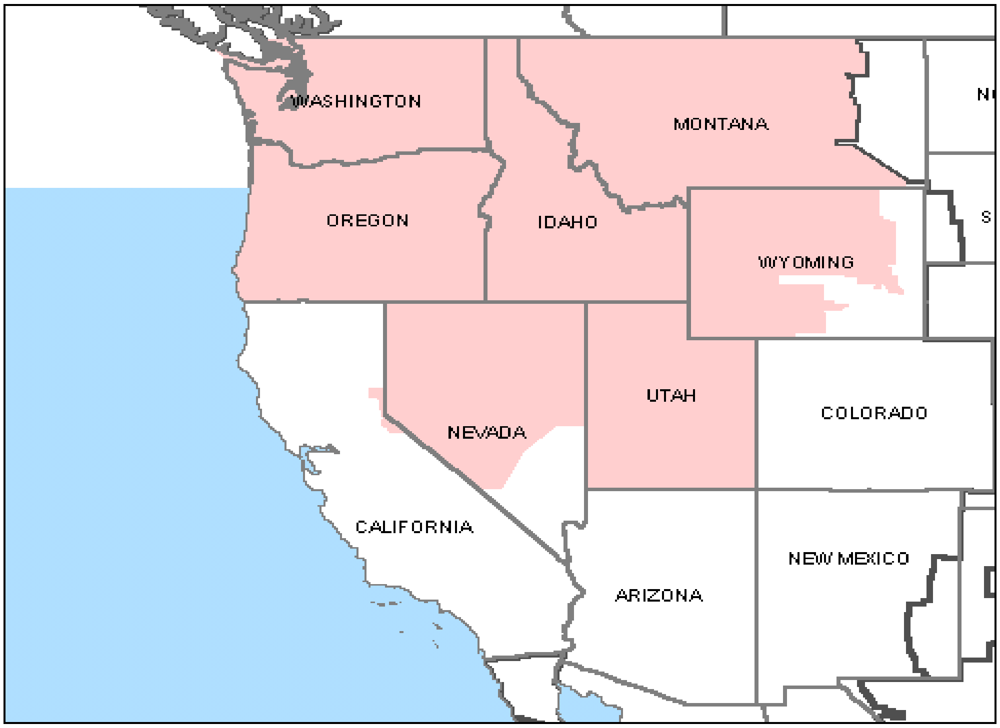


Figure 2. Generation Resource Capacity and Hydro Ownership in the Northwest

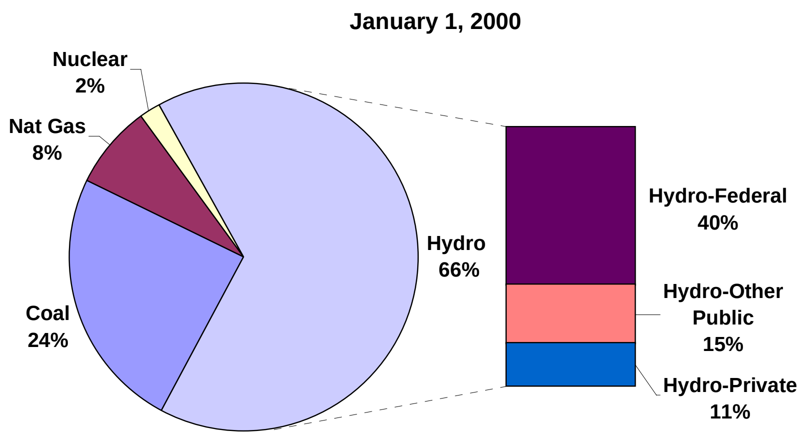


Table 1. Northwest Capacity Changes by Plant Type, 1991 to Present

	Capacity in Megawatts			
Plant Type	**1996-2000**	**1991-1995**	**Total 1991-2000**	**Current Capacity**
Additions to Operating Capacity				
Combine Cycle	1,091	962	2,053	2,587
Gas Turbine	69	447	516	1,155
Hydro	48	352	400	35,575
Nuclear			0	1,107
Steam	34	339	372	14,668
Total	1,241	2,100	3,341	55,091
Capacity Retirements				
Combine Cycle			0	2,587
Gas Turbine	240	59	299	1,155
Hydro	1	26	28	35,575
Nuclear		1,944	1,944	1,107
Steam	99	160	260	14,668
Total	340	2,190	2,530	55,091
Net Capacity Additions				
Combine Cycle	1,091	962	2,053	2,587
Gas Turbine	-171	388	217	1,155
Hydro	47	326	372	35,575
Nuclear	0	-1,944	-1,944	1,107
Steam	-66	178	113	14,668
Total	901	-90	811	55,091

Note: Internal combustion plants included in gas turbine category. Other plant categories not listed contributed 150 Megawatts of net capacity additions from 1991 to 2000.
Source: Resource Data International, PowerDat Database, January 2001.

The low rate of additions to capacity in the Northwest has corresponded to an equally low rate in California, changing the pattern of generation needed to meet demand in the Pacific Northwest (Washington and Oregon) region and California.[3] Resources in the Pacific region have been run more frequently and other areas of the West have increased their share of total western generation. Table 2 shows the growth of generation in the Pacific region and the overall west. As the table shows, generation in the Pacific region increased by 37 billion kilowatthours (BkWh) from 1995 to 1999, an 11% increase from a virtually unchanged resource base over the period.

[3]California, Oregon and Washington make up the Pacific census region, and will be referred to as the "Pacific region."

Table 2 shows a shift in generation away from resources in the Pacific to other areas of the west. From 1995 to 1999, generation in the West outside the Pacific region grew by 58 BkWh, or 22 percent. This rate of generation increase was twice the rate in the Pacific region. Although increases in demand outside the Pacific account for some of this increase, the increased generation also substituted for the lack of additional capacity in the Pacific region.

Table 2. Total Generation in the Pacific Region and the West, 1995 to 1999
(Million Kilowatthours)

	1995	1996	1997	1998	1999
			Utility Generation		
Washington	95,671	112,606	117,453	97,128	112,072
Oregon	44,031	47,884	49,068	46,351	51,698
California	121,881	114,706	112,183	114,928	87,875
Pacific Region Total	261,583	275,196	278,704	258,407	251,645
Rest of the US West	258,329	266,925	281,928	307,433	296,479
Pacific as % Total West	50.3	50.8	49.7	45.7	45.9
			Non-Utility Generation		
Washington	6,703	6,216	4,859	5,203	5,181
Oregon	1,321	3,239	3,446	4,921	5,126
California	63,935	63,484	62,422	76,021	108,228
Pacific Coast Total	71,959	72,939	70,727	86,145	118,535
Rest of the US West	12,263	13,480	13,744	13,689	32,475
Pacific as % of Total West	85.4	84.4	83.7	86.3	78.5
			Total Generation		
Washington	102,374	118,822	122,312	102,331	117,253
Oregon	45,352	51,123	52,514	51,272	56,824
California	185,816	178,190	174,605	190,949	196,103
Pacific Coast Total	333,542	348,135	349,431	344,552	370,180
Rest of the US West	270,592	280,405	295,672	321,122	328,954
Pacific as % of Total West	55.2	55.4	54.2	51.8	52.9

Source: Resource Data International, PowerDat Database, January, 2001.

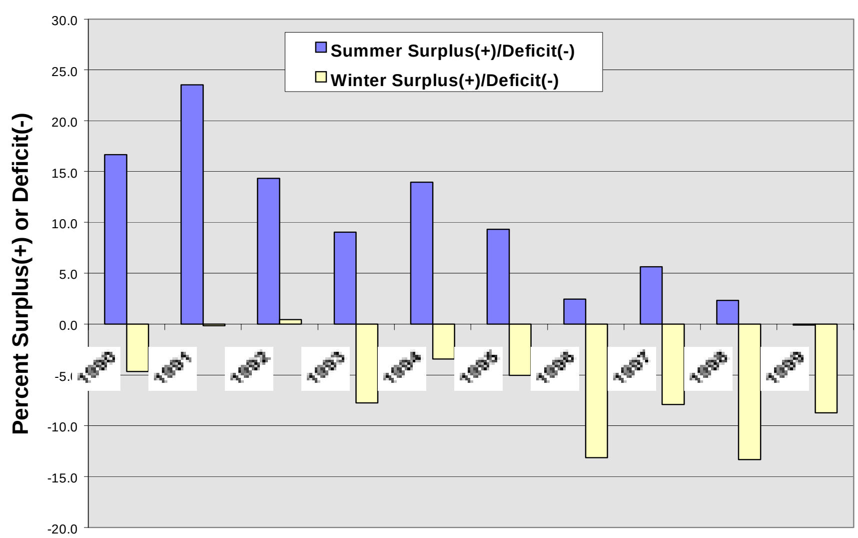
Table 2 also shows the shift in ownership of generation from utilities to non-utilities. Most of the increased non-utility share in the Pacific has been in California. California has historically taken a large share of its power from non-utility sources, but the proportion increases dramatically in 1998 and 1999 from around 63 BkWh (1995 to 1997) to 108 BkWh in 1999, in large part a result of selling off utility generation capacity. States in the Northwest have not undertaken a program of retail access or divestiture of utility assets comparable to California. The Northwest has seen much more modest shifts toward non-utility sources: Washington decreased over the 5-year period, with only around 5 percent of generation from non-utility sources, while Oregon increased significantly from a small base in 1995 to around 9 percent in 1999.

Northwest Energy Balance

The Northwest is a winter-peaking region. Typically, it provides power to California and other southern areas of the west in the summer and receives power from these areas during the winter. Thus, the Northwest has surplus power needs that it markets to the south in the summer, but runs a deficit in the winter during its peak winter period. Although the Northwest has a power deficit during the winter, the Northwest is generally less dependent on outside resources to meet load than California, in part because of the historically abundant sources of hydropower. However, water for generation may also be needed to preserve water or maintain stream flows for other water uses or for environmental mitigation. During a low water year, the Northwest will have less surplus power for other regions during the summer and greater needs for power from those regions during the winter.

Since 1990, the Northwest's dependence on resources outside the region has increased, as the summer surplus of capacity over peak load has diminished and the winter capacity deficit has widened. This trend is shown annually in Figure 3. This figure shows the winter and summer peak loads in the Northwest and the corresponding

Figure 3. Northwest Capacity Surpluses and Deficits 1990 to 1999



Source: Resource Data International, PowerDat Database, January, 2001.

generation capability. Although some year-to-year variation is to be expected, due to variation both in energy demand and in energy supply limitations on hydro resources, the trend is clearly downward, reflecting the increasing need to rely on power generated outside the area.

Historical Purchase and Trade Patterns

Western utilities actively traded wholesale electric power before the advent of restructuring. Although transmission constraints can limit trade at times, these constraints are not generally binding and power can be freely traded at most times. The average rates for wholesale purchases by utilities are shown in Table 3. Over the 10-year period of the 1990s, rates are seen to increase and to come closer together. When wholesale trading was smaller in scope than today, and cost based, low prices frequently reflected surplus conditions and prices in one area could be low while they were high in another. As trade has moved to market-based pricing in recent years, the spread of prices has narrowed. In 1999, for example, the spread in the average purchase cost per MWh across the Arizona, Northwest and Rockies regions was only $4/MWh; in 1990 it was $18 and in 1995 it was $10.

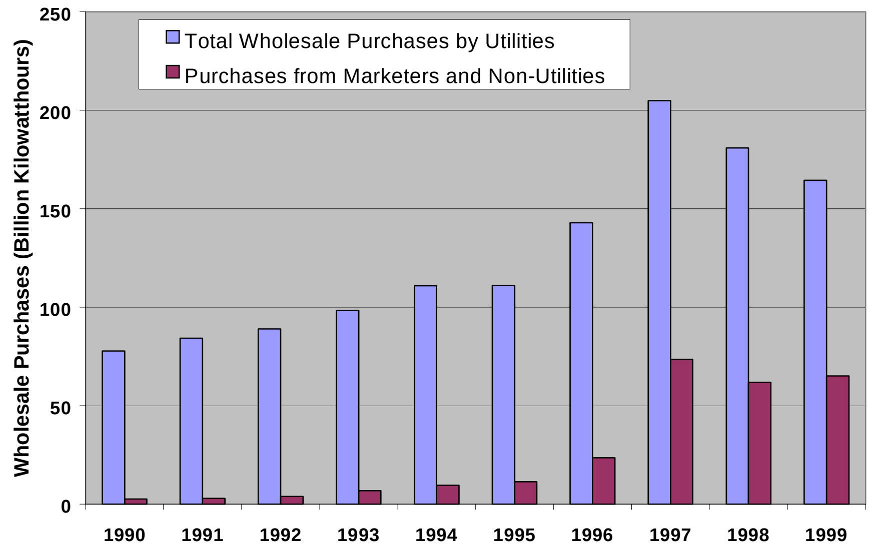
The convergence of prices outside California has been accompanied by dramatic increases in volumes purchased. These volumes reflect both increased reliance on trade for supplying loads, but also increased wholesale activity on the part of the utilities themselves. Both the level of trade and proportion of purchases from marketers and non-utilities have increased dramatically, as shown for the Northwest in Figure 4.

Table 3. Average Cost of Power Purchases by Utilities 1990 - 1999 ($/MWh)

	WSCC Subregion				
Year	Arizona	California	Northwest	Rockies	Total
1990	$38	$53	$20	$28	$38
1991	$36	$52	$20	$30	$37
1992	$38	$57	$22	$32	$40
1993	$36	$58	$25	$31	$41
1994	$37	$61	$27	$36	$42
1995	$35	$57	$25	$35	$40
1996	$32	$54	$29	$34	$36
1997	$31	$50	$24	$35	$33
1998	$30	$55	$29	$36	$36
1999	$27	$45	$31	$30	$35

Source: Resource Data International, PowerDat Database, January, 2001.

Figure 4. Utility Wholesale Power Purchases in the Northwest 1990 to 1999



Source: Resource Data International, PowerDat Database, January, 2001.

3. Northwest Markets During the Summer 2000

The high prices and the power crisis in California were the main focus of attention in the summer of 2000, but the underlying problems were wider regional ones, and the Northwest felt the impact as well. Residential and small commercial customers were not directly exposed to short-term market prices, as they were in San Diego. As Table 2 above shows, most of the generation in the Northwest is utility-owned, and the impact of the high prices in the spot market is lessened by the relatively small proportion of the overall market exposed to those prices. Nevertheless, the recent increases in price have been large and sustained, and the degree of dependence on external supplies or the spot market varies by individual utility. This section provides a general description of how the western market over the summer affected conditions in the Northwest, and provides some limited information on the likely, eventual impact of those prices on customers.

Prices and Sales

Spot Market Price Patterns

Although power market prices spiked at certain points over the summer, the recurrence of high prices over the longer term may have a greater impact on customer bills. Prices spiked less frequently as the summer progressed and California imposed price caps at lower levels, but average prices continued to climb. This climb in prices can be observed in the spot prices at the California-Oregon Border (COB) and at receipt points along the Columbia river (Mid-C) by averaging the daily prices over the previous 30-day period and plotting the trend as shown in Figure 5. A large, but short-lived spike in prices will appear as a jump in the 30-day average, followed by a gradual reduction in the average price. Figure 5 shows a very different pattern: average prices jump up, but they stay at the higher level until the middle of September.

Natural Gas Spot Prices

The cost of natural gas as an input to power generation is one factor in the rising power price. For much of this period, natural gas was the marginal fuel for power generation, at least in California. So it is reasonable to assume that the rising trend in power prices was driven in part by a corresponding rise in gas prices at western delivery points. Figure 6 show the gas prices corresponding to the power prices in Figure 5. The price pattern seems to have four distinct stages:

(1) A moderate rise from around $2.50 per MMBtu from the beginning of the year to about $3.00 per MMBtu in late May;

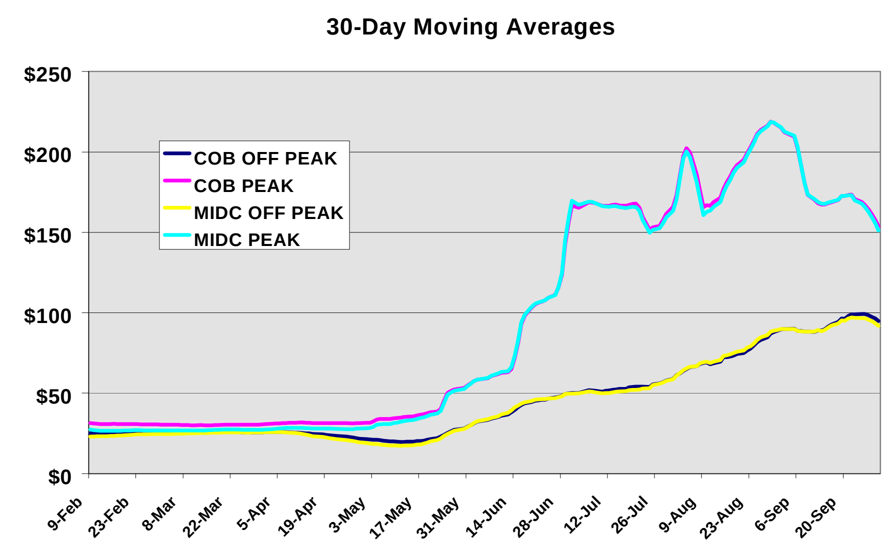
(2) A more rapid rise to the $4.00 level at the end of June, corresponding to the initial stages of the problem in California;

(3) A leveling off at $4.00 in July and early August, corresponding to moderating weather and load conditions in July; and

(4) A return to the rapidly rising trend in late August and September, to a level over $5.00 by the end of September.

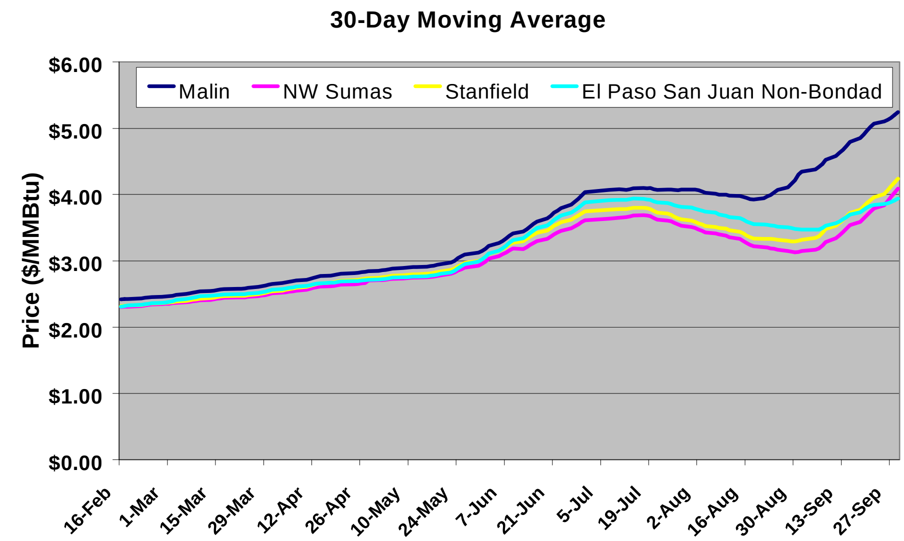
Unlike power prices, spot natural gas prices gave no indication of a falling trend at the end of September. While there seems to be a relationship between gas and power prices in spot markets, it is clearly not simple and direct. Prices for both increase over the period, but at very different rates: gas moves from around $2.50 in May to over $5.00 in September, approximately doubling. Over the same period, power prices moved from around $25 in May to $150 to $200 in September, a six- to eight-fold increase.

Figure 5. Mid Columbia and COB Prices, February to September 2000



Source; *Megawatt Daily*

Figure 6. Spot Market Natural Gas Prices



Source: *Gas Daily*

Sales and Revenue by Sector

Preliminary sales and revenue data for the summer do not yet show an indication of rising prices to consumer in residential and commercial sectors. As shown in Table 4, residential sales in the period of May through August have grown from 1995 to 2000, increasing 20 percent over the period; prices grew 6 percent from 1999 to 2000, but this growth does not appear to be significantly higher than in previous years. Industrial sales, on the other hand, have been flat over the period, with year 2000 sales increasing less than 1 percent over 1995.

Residential and commercial power revenues per MWh increased only 1 percent in 2000 over 1999. However, there have been several reports of requests for rate increases by utilities, so there will be some longer term rate impact.[4]

Some indication of potential rate increases may be reflected in increases in industrial prices, which are more likely to quickly reflect pass-through of changes in

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[4]The Eugene Water and Electric Board received an increase of 15 percent. Seattle City Light has had two 6-percent rate increases and a 10-percent surcharge.

Table 4. Northwest Sales and Revenue, Totals for May through August, 1995 to 2000

	1995	1996	1997	1998	1999	2000
Residential and Commercial Sectors						
Sales	25.6	27.4	25.8	28.0	29.1	30.9
Average Revenue/Mwh	$56	$58	$58	$58	$57	$58
Industrial Sector						
Sales	22.7	20.5	21.4	23.7	23.1	22.8
Average Revenue/Mwh	$32	$32	$29	$28	$29	$34

costs to the utility than are rates for residential and commercial customers. Industrial average revenues for May through August of 2000 show increases of 20 percent over May through August of 1999 for the Northwest as a whole. Increases varied considerably by state and utility over the summer. In the month of August, for example, the increases in 2000 over August 1999 were largest in Washington (34%) and Oregon (24%), while the remainder of the West had increases of only 4 percent. One utility, Puget Sound, had an increase of 158 percent, from $33/MWh to $84/MWh, and others had increases in the 30% to 50% range.[5]

Generation and Input Costs

Northwest Generation by Resource

The summer period, May through September, shows two main changes from the pattern of generation in prior years: lower hydropower generation and higher natural gas generation. Hydro generation fell 13.3 million MWh, a decrease of 20 percent from the average of the previous 5 years (see Figure 7.) The loss of hydropower generation was made up by a three-fold increase in natural gas generation (from 3.3 to 10.2 million MWh) and increases in other steam generation from coal and nuclear power plants.

The increase in gas use is a significant increase over prior years, but the trend has been consistently upward, as shown in Figure 8. Some of the increase reflects the addition of new combined cycle capacity, but it also may reflect increased use of older gas steam facilities. Coupled with the increases in gas use elsewhere in the west over the summer, it reflects a new level of gas use in electric generation that can have a significant impact on gas usage if it coincides with peak gas use periods in the winter.

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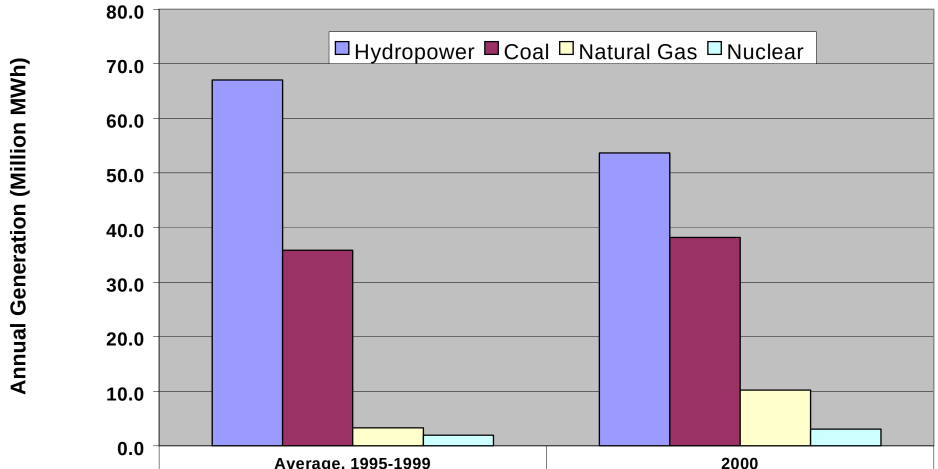
[5]Source: RDI PowerDat Database, January 2001. Information based on a sample of utilities in each state.

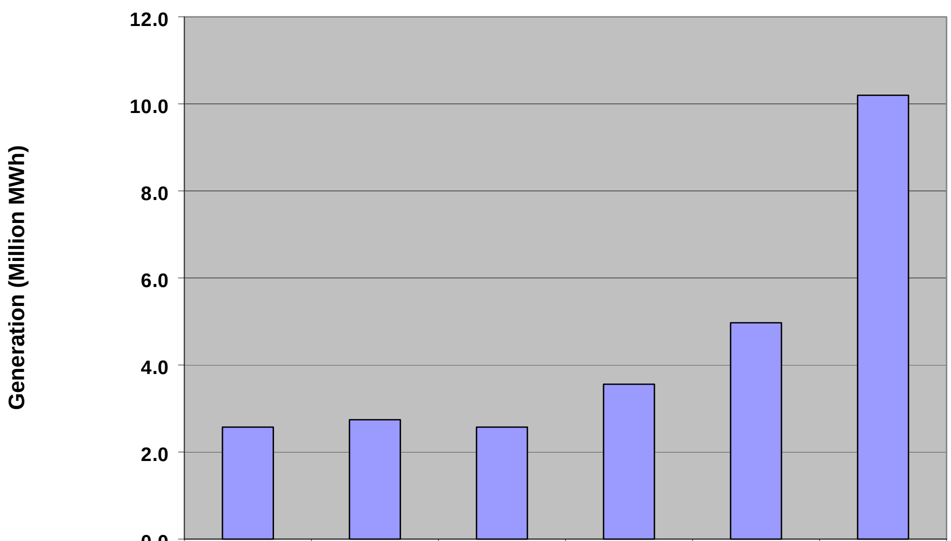
Figure 7. Total Power Generation by Resources in the Northwest, May to September



	Average, 1995-1999	2000
Hydropower	67.0	53.7
Coal	35.8	38.2
Natural Gas	3.3	10.2
Nuclear	1.9	3.1

Source: Resource Data International, PowerDat Database, January, 2001.

Figure 8. Power Generation from Natural Gas in the Northwest



	1995	1996	1997	1998	1999	2000
Natural Gas	2.6	2.7	2.6	3.6	5.0	10.2

Source: Resource Data International, PowerDat Database, January, 2001.

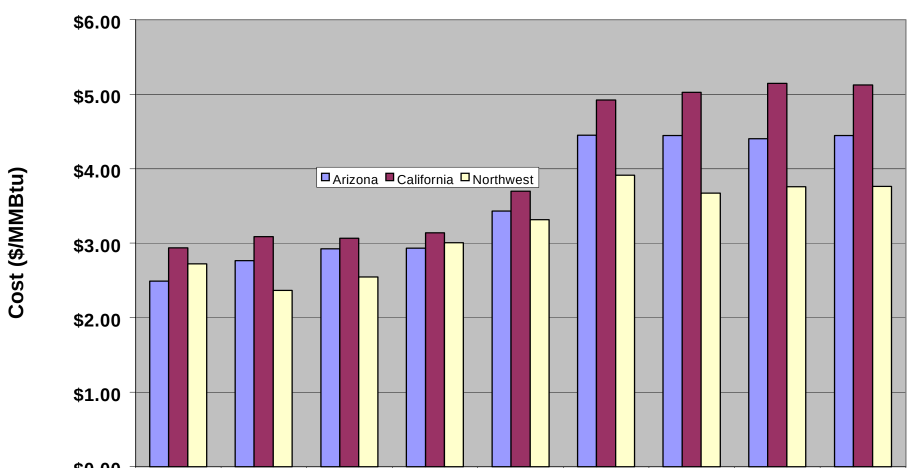
Gas Cost Increases to Utility Plants

The increases in gas use over the summer coincided with the increase in the spot market price of gas. The increases in the spot market price reported in the trade press can be compared with actual gas costs reported at electric utility plants. The gas cost at electric plants in the West is shown in Figure 9. Northwest gas costs increased less than costs in other western regions, starting out the summer near the spot market levels of around $3.00/MMBtu, and ending the summer under $4.00/MMBtu when the spot market price went above $5.

Environmental Factors and Weather Conditions

The Northwest was not directly impacted by the high environmental costs of power generation that raised generation costs in southern California. Since power price increases in one region of the West rapidly translate into increases throughout the West, however, these factors are likely to have had significant indirect impact by raising market prices for power throughout the west.

Figure 9. Gas Costs at Western Electric Utilities, January to September 2000



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona	$2.49	$2.77	$2.93	$2.93	$3.43	$4.45	$4.44	$4.40	$4.45
California	$2.94	$3.09	$3.07	$3.14	$3.70	$4.92	$5.02	$5.15	$5.13
Northwest	$2.72	$2.37	$2.55	$3.01	$3.32	$3.91	$3.67	$3.76	$3.76

Source: Resource Data International, PowerDat, January, 2001.

The most direct environmental impact in the Northwest is on the availability of water for hydropower generation. The largest impact appears to have resulted from the pattern of runoff during the spring.[6] Over the summer months, Northwest stream flow conditions appear to have been near normal.

Weather conditions in the Northwest during the summer were not as extreme as in other areas of the West. May, June and August were well above normal, but July was near normal. These conditions would not tax the power system in the Northwest under normal conditions, since the summer is not the peak season in the region. However, when combined with the hydropower conditions, they did serve to limit the ability of the Northwest to supply power to California and the Southwest.

[6]See Bulk Power Report, Vol 1, p 2-24.

4. Northwest Markets in November and December, 2000

This section describes the recurrence of high prices and price spikes in the Northwest in November and December 2000, and then discusses the fundamental factors contributing to those spikes. It concludes with a short statistical analysis that quantifies some of the leading factors and uses them to estimate the pattern of power prices in November and December.

Spot Market Power Prices and Volumes

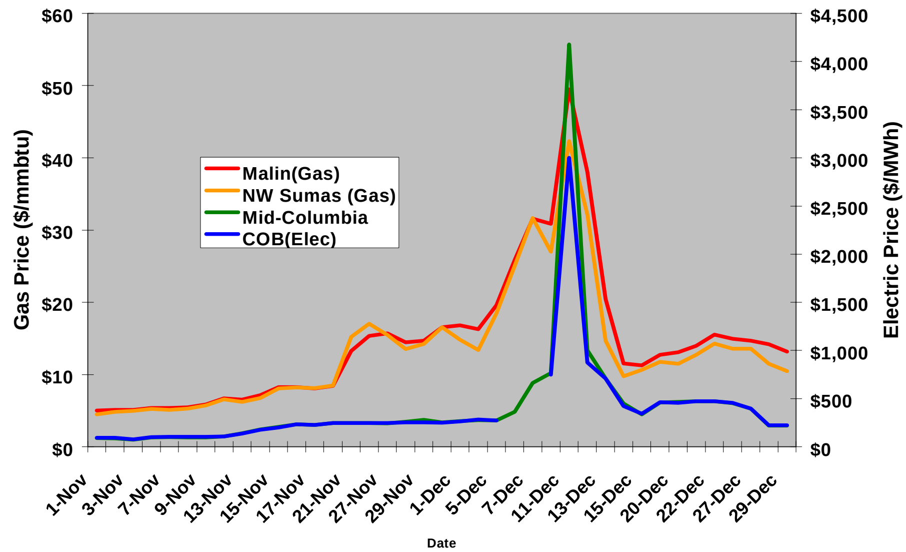
In September and October, power prices appeared to be moderating from the sustained high levels of the summer. Prices continued to fluctuate considerably, but the trend was clearly downward from late August prices over $200 ($225 at Mid-Columbia on August 29) to prices under $100 in early November ($75 on November 4.) In mid-November, prices for natural gas and electricity started to rise again (see Figure 10.) The increases at first were small enough to be attributed solely to anticipation of the winter peak season, but then gas prices jumped over $10 per MMBtu and electricity prices rose to over $200. This significant trend was punctuated by dramatic increases in early December, but returned after the spikes subsided to close around $300 during the last week of December.

The December prices were foreshadowed by the balance of the month prices at the beginning of December. Balance of the month trades of $310 for December were reported at Mid-Columbia, while prices of $245 at NP15 and $189 at Palo Verde were reported.[7] The higher prices at Mid-Columbia underscore the market perception that the Northwest was likely to be the area of greatest power needs during December. This pattern is reinforced by a comparison with December forward prices a few days earlier: $220 at Mid-Columbia, $190 at NP15, and $180 at Palo Verde.[8] Not only do these prices show the rapid increase in forward prices for December, they also show that the Northwest led the increase, with Mid-Columbia up $90, while NP15 rose only $55 and Palo Verde only $9. Clearly, there were anticipated problems in getting power to the Northwest in December.

[7] *Megawatt Daily*, December 1, 2000.

[8] *Megawatt Daily*, November 27, 2000.

Figure 10. Northwest Spot Gas and Electric Prices, November and December 2000



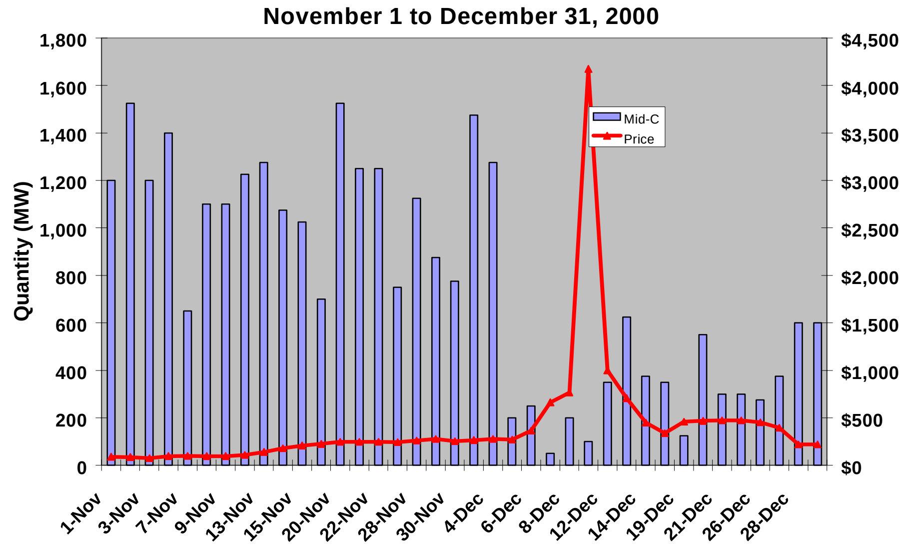
Source: *Megawatt Daily, Gas Daily*

The pattern of natural gas prices tracked with the pattern of power prices (see Figure 10). Power prices did not follow the rapid run up in natural gas prices in the last week of November, but otherwise shifts in power prices appear to mirror shifts in natural gas prices. The last week in November set the stage for the natural gas price increases: the natural gas price at Sumas, Washington, started the week at $8.50 on November 20 and doubled to $17.04 in two days, just before the Thanksgiving holiday. Frigid weather, pipeline operational flow orders (OFOs) on several regional pipelines (Northwest, PG&E, Transwestern and El Paso) and the "dire status" of Southern California gas storage conditions were all cited in trade press accounts as key contributing factors in the rapid gas rise.[9] The speed and size of the natural gas price increase appeared to take the market by surprise, and no immediate impact was seen in power prices.

The power price spikes came in early December, when prices began to rise in the week beginning Monday, December 4. At the end of the week, on December 8, prices for the following Monday, December 11, jumped to over $4,000 at Mid-Columbia and to

[9]*Natural Gas Intelligence, Gas Price Report*, November 27, 2000.

Figure 11. Price and Quantity at Mid Columbia, Day-Ahead On-Peak Power



Source: *Megawatt Daily*

$3,000 at the California-Oregon border. The factors contributing to the rising trend and the price spikes are discussed in the remainder of this section.

Although prices spiked to extraordinary levels on December 11 and 12, as shown in Figure 10, it is not clear how much power was purchased at these prices, and we lack available information to determine the degree of exposure of utilities and their customers in the Northwest. Based on the volumes reported in *Megawatt Daily*, however, it does appear that overall quantities bought diminished as prices spiked (see Figure 11.) The quantities reported in *Megawatt Daily* do not represent estimates of total market quantities, but only the actual quantities included in the price survey. If changes in these quantities are representative of general changes in the market, they do show a marked reduction in purchase quantities beginning in the first week of December when the market began to founder and prices started their path to extreme values.

Weather and Hydro Conditions

As noted in the last section, Northwest weather and climatic factors, specifically temperatures and stream flow conditions, did not appear to be critical factors over the summer or during the early fall. But temperature, precipitation and stream flow conditions changed for the worse during November and early December.

Figure 12 shows the monthly temperature rankings from September to December in three western regions, showing that the entire west experienced an extremely cold November. Nationwide, November was reported as the second coldest November of the 106 on record, with only the winter of 1911 being colder. Idaho, Wyoming, Utah and Arizona experienced their second coldest winters on record, and California and Colorado their third coldest.[10]

Figure 12 shows general temperature conditions, but doesn't show how closely related concerns about weather during the week of December 11 were in early December when prices started to rise. Forecasts during the first week of December anticipated a "polar pig" arriving the next week and bringing record-breaking temperatures for the entire west. The frigid temperatures were forecast to last the entire week[11]. These forecasts combined with a series of Stage 2 emergencies at the California ISO, fueled the trading on Friday, December 7, when prices for power delivered on Monday, December 11, rose to $4,000 at Mid-Columbia. During the week beginning Monday, December 11, the extreme cold arrived, but the extreme conditions did not last quite as long as predicted, with a moderating trend through the week. Prices subsided as temperatures moderated.

Extreme cold was not the only weather-related factor in the power shortages and high prices. Precipitation in the Northwest, which had been at least at normal levels in September and October, fell to low levels in November and December (see Figure 13) raising growing concerns about the available hydropower at the normal peak winter period in January or February. The precipitation conditions were accompanied by a significant shift in stream flow conditions from normal to low levels through November. The Figure 14 shows how the average stream flow index for Washington fell rapidly until mid-December, reinforcing other demand and supply conditions leading up to the December price spikes.

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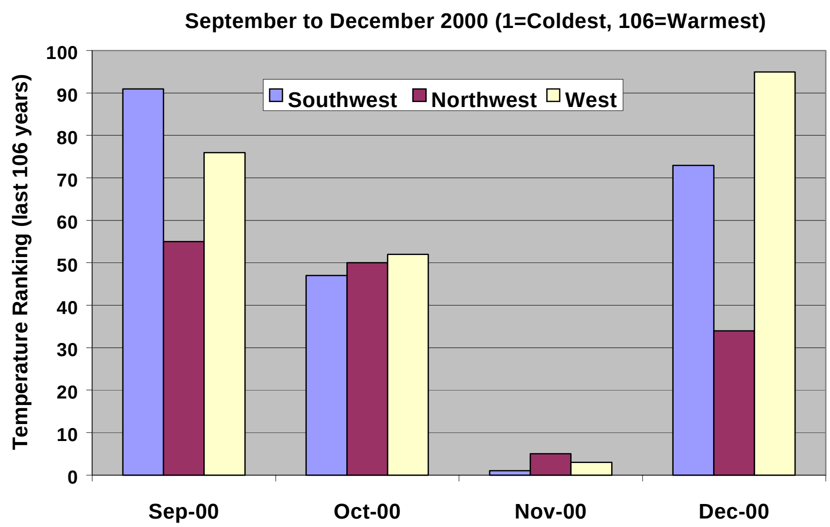
[10]*Natural Gas Intelligence*, December 11, 2000, based on reported information from Salomon Smith Barney.

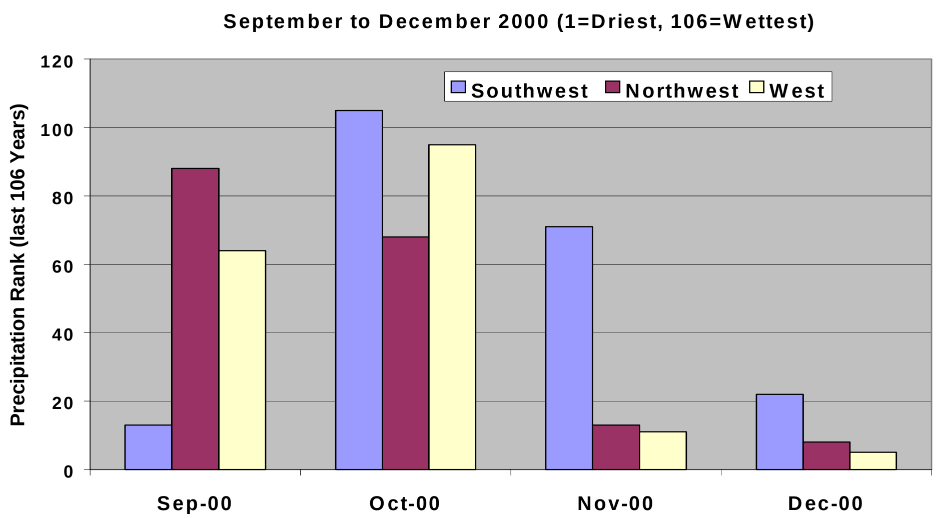
[11]Salomon Smith Barney meteorologists Jon B. Davis and Mark Russo, quoted in *Natural Gas Intelligence*, December 11, 2000.

Figure 12. Rank of Regional Temperatures



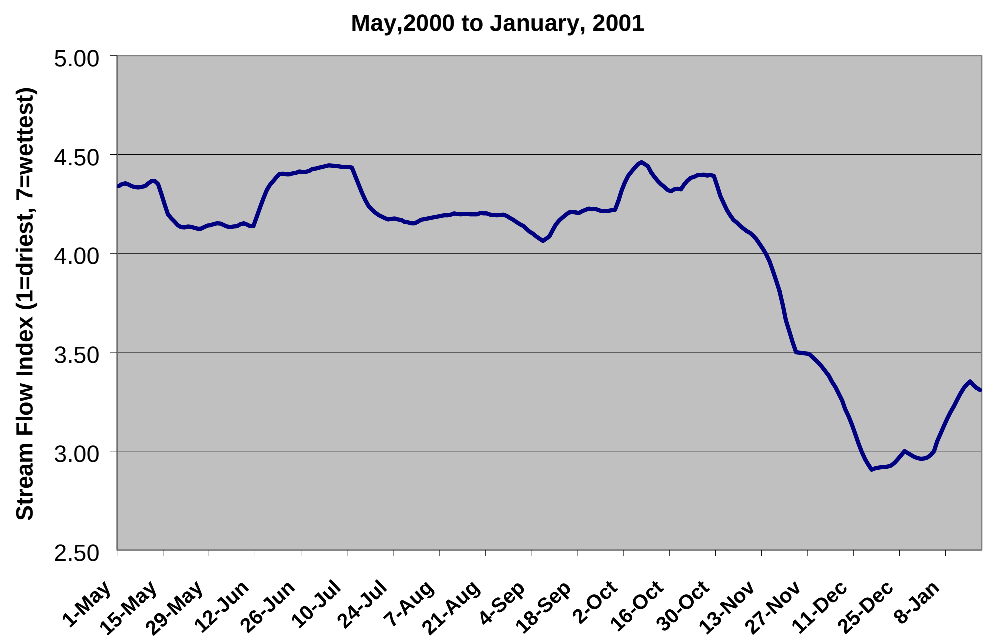
Source: NOAA website, www.ncdc.noaa.gov/ol/climate/research/caq3/caq3.html

Figure 13. Rank of Regional Precipitation



Source: NOAA website, www.ncdc.noaa.gov/ol/climate/research/caq3

Figure 14. Stream Flow Index for Washington State

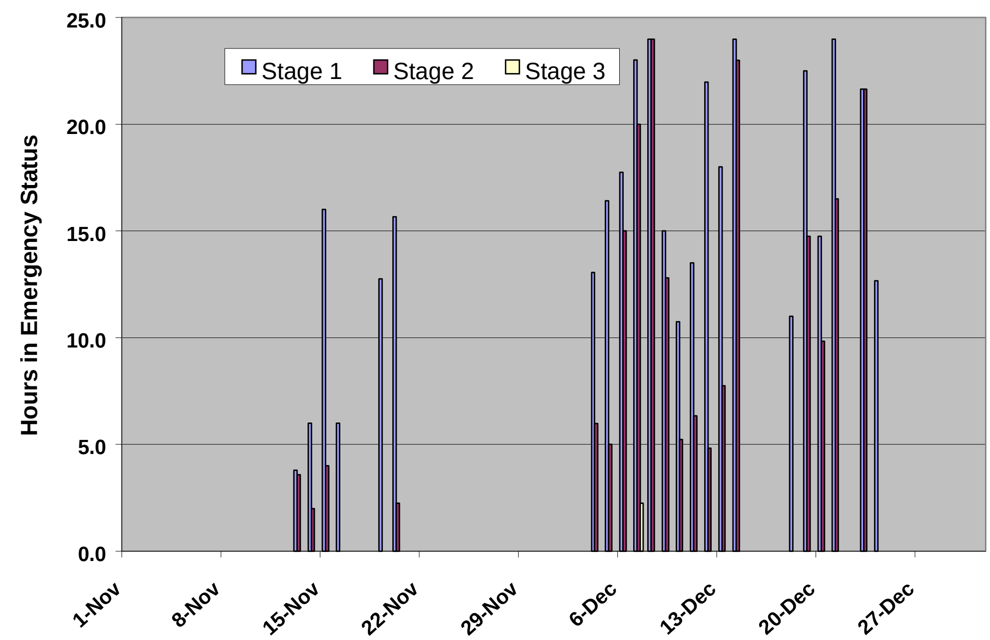


Source: USGS web site: water.usgs.gov/cgi-bin/average_daily?wa

Other Factors Contributing to High Prices and Price Spikes

Several other key factors contributed to the power shortage and price events. There were no emergency conditions at the California ISO in October, permitting power prices to moderate somewhat. As power shortage concerns deepened in December, California experienced a return of emergency conditions. These conditions show up clearly in Figure 15, which plots the hours under each of the emergency stages for the days in November and December. The emergencies were a result of worsening supply and demand conditions, but they fed back into the market, creating additional market stress about the ability to find supplies to meet demand and making the market aware of the vulnerable status of the California ISO.

Figure 15. California Emergencies: Hours in Emergency Status

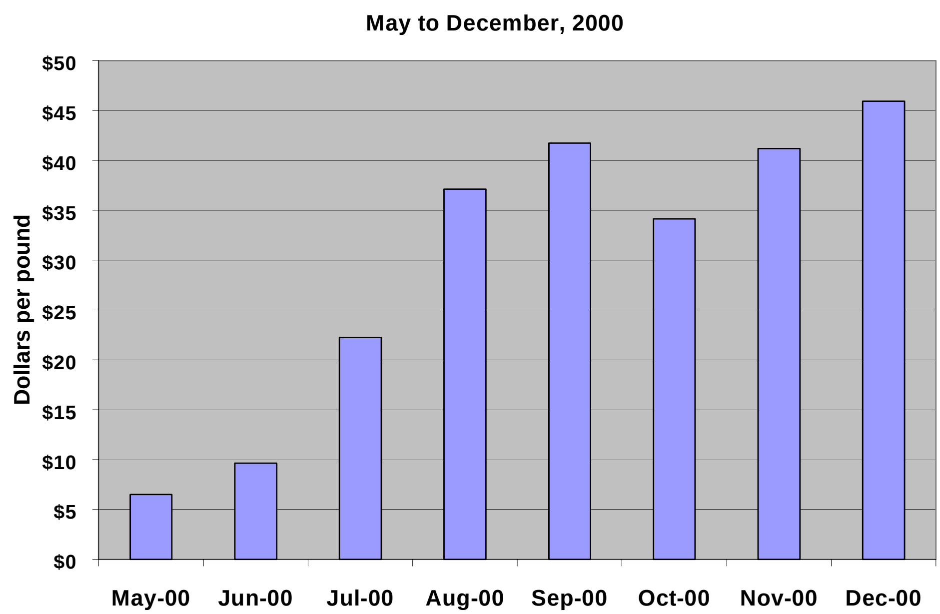


Source: California ISO

Environmental factors continued to exert further stress during the period. For natural gas supply, they affected both price and quantity. First, prices for NOx permits continued at high levels (see Figure 16) in Southern California. The rules governing the use of these permits make it difficult to directly estimate the impact of their prices on generation costs, but prices at the levels seen since August 2000 are bound to exert upward cost pressure on prices in Southern California and influence power prices in the west when gas is on the margin. Given the conditions in California, gas could be expected to be on the margin much of the time. The impact can be particularly pronounced under emergency conditions, when older units with very high NOx emissions rates are needed to meet load.

Second, environmental restrictions could prohibit certain plants from running at any price. When plants are subject to hard limits on output of NOx emissions, special waivers are needed to permit the plants to run. The need to obtain permits, and the negotiated outcomes that arise, make the environmental component of power pricing an even more uncertain exercise than it is under more normal conditions. This condition occurred during critical times in November and December: 2000 MW of AES gas-fired capacity were taken offline at the end of November under regulatory pressure to install

Figure 16. NOx Reclaim Prices for SCAQMD



Source: Cantor-Fitzgerald web site.

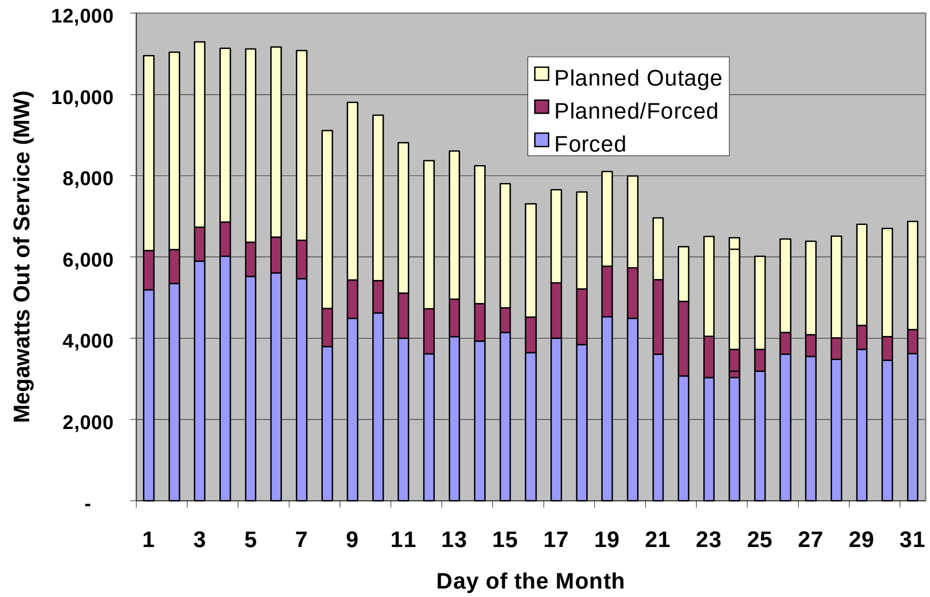
scrubbers. This capacity was returned to service after the high prices on December 11, when AES reached an agreement with the South Coast Air Quality Management District that eased penalties and permitted the capacity to return.

Finally, there are environmental requirements to maintain flow levels for the protection of fish populations which limit the use of water for power generation. As stream flows diminish, the need to release a certain amount of water to preserve the environment will have a major impact on the available energy from hydropower in the Northwest. The water level behind Grand Coolee Dam in the Northwest is the second lowest of the last 25 years, approaching the level in 1989, a level far below all other years from 1975 to date.[12]

Outages were commonly cited by the California ISO as a contributing factor in California emergencies, and appear to have been important in other geographic areas as well. The only systematic outage data available for this study were from the California ISO for December. These data show that outages were high during the first week in December, but were lower in the remainder of the month (see Figure 17.) The specific relationship between these outages and power shortages and prices cannot be determined

[12]Assessing the 2001 Outlook, Northwest Power Planning Council

Figure 17. December 2000 Outages, California ISO



Source: California ISO.

from these data. The high level of outages during the week of December 4 to 10 probably contributed additional market stress as prices began to rise, and the lower level during the week of December 11 to 18 probably contributed to the relatively swift fall of prices from the highest levels. It is difficult to draw any further conclusions from these data, and no conclusions can be systematically extended to the Northwest.

Although we lack detailed quantitative information outside California, it appears, from trade press reports, that some scheduled maintenance was delayed from October to November out of concerns that high temperatures would last through October.[13] The normal winter period is January, so a large amount of planned maintenance was still being performed in December. These conditions are consistent with the level of planned maintenance shown in the California ISO data in Figure 17. In addition, three large nuclear units were out of service for scheduled maintenance at the same time in November. One of them, Diablo Canyon-1 was delayed for two weeks, finally returning around November 22. None of these conditions is inherently suggestive of a pattern of withholding. Even when specific requests to delay maintenance were granted, the results could be mixed. Maintenance on Diablo Canyon-2, scheduled for 4 days at the beginning of December, was delayed until the second weekend in December, from

[13] *Power Markets Week*, November 20, 2000.

December 9th to 11th. As a result the unit went down for maintenance, just as the power price for Monday, December was spiking to $4000 at Mid-Columbia. The unit came back into service late in the day on Monday, in time to contribute to moderating prices during the week, but too late to help mitigate the dramatic spike on Monday.

Combining the Factors: a Descriptive Statistical Analysis

Several of the factors discussed in this section were quantified and developed as a daily time series of prices and conditions. The time series was then used to quantify the relationship between power prices and these factors. The following factors were used in a statistical analysis of on-peak, day-ahead power prices reported in *Megawatt Daily* for the Mid-Columbia delivery point:

- *Temperature Conditions in the Northwest.* The temperature in Seattle as reported by the Accuweather.

- *Emergency Conditions in California*. For this purpose, the presence of emergency conditions was measured by the number of minutes in Stage 2 emergency each day, using data from the California ISO.

- *Stream Flow Conditions*. This measure used daily stream flow information for Washington. Two separate measures were constructed: an average index for each day across all streams, and a percentage of streams with flows below the 25th percentile.

These operating variables were used in a regression analysis to explain the price of power at Mid-Columbia. Using a statistical measure know as the coefficient of determination, or R^2, these variables are highly significant and explain 94 percent of the variation in the Mid-Columbia power price. This result confirms the belief that these fundamental operating conditions were important in explaining the price of power.