Open Market Electricity Prices

By

Anthony Jones
P.O. Box 1914
Boise, Id. 83701
208-344-0809
tjones@micron.net

August 13, 1999

Prologue

In early 1998 I circulated a paper titled, "Market Conditions After Deregulation for Northwest Electric Utilities." The impetus for preparing the previous paper was my curiosity as to what effect electricity deregulation would have on consumers in the northwest in general and Idaho in particular. It is probably significant that when I started my research I was predisposed to believe that electricity deregulation would be a disaster for people and businesses in the northwest.

Effectively, there is only one theory as to why electricity in the northwest is cheaper than electricity in most other regions. That theory of course is that Hydro is Cheaper (HIC). According to the theory, our rates are lower because we have a higher percentage of hydro based generation than other parts of the country. Hydro power is supposedly cheaper than other forms of generation because the "fuel", falling water, unlike coal or gas, is free. Recognizing that Sun and wind are also free but are not generally accepted as a viable means of generating electricity is a contradiction to the HIC theory that is typically ignored. In any event, the HIC theory works at the gut level and I, like most people, used to believe it. And, it is easy for this belief to persist. As long as northwest rates continue to be low, there is little reason for most people, even people in the industry, to explore the real reason as to why northwest rates are low.

Unfortunately, the HIC theory is weak.

Some hydro facilities, particularly the older ones, do in fact appear to produce electricity inexpensively. They should. As mentioned before, the fuel, falling water, is usually free. What most parties, especially the utilities, usually forget to mention is that the land the dams and reservoirs sit on was often free as well, as is much of the water management staff, which is supplied in part by state and federal agencies such as the Department of Water Resources and the Weather Bureau. Construction decisions often overlooked environmental issues that would not be permitted today. Examples include main stem Columbia and Snake River dams that do not have fish ladders even though it was known at the time that salmon runs would be decimated or eliminated when the dams were constructed. In the case of federal projects part or all of the dams themselves were occasionally free to their electricity marketing agencies. And, even when the full cost of the hydro structures were scheduled for repayment by electricity rates it is important to remember that many of the larger facilities were constructed during the 1930s and 1940s with depression level wages and financed at depression level interest rates. Labor rates of $1 per person per day or lower, interest rates of 3% or lower, high levels of subsidization, substantial numbers of outright grants, and the grandfathered avoidance of many environmental regulations, will do wonders for any company's rate structure.

And, that is the good news. The bad news begins with the recognition that some hydro plants are not economical. Many recent retrofits and PURPA hydro projects require 40 - 50 mill energy rates to get full returns on the investment when the open market for energy is 25 mills or less. A good example is Atlanta Power, in Atlanta, Idaho. Atlanta Power, is one of the very few 100% hydro based utilities in the nation. For 1200 Kwh's per month, the Idaho residential average, Atlanta's rate is $0.097 per Kwh. This is one of the highest electricity rates in the nation. The lesson that should not need learning is that the word "hydro" is not a substitute for due diligence. It is still important to review each project on its own merits. For more examples, see Appendix 1.

To make matters worse for hydro in the future, all of the best locations to site dams are taken. As the demand for energy continues to increase with increases in population and manufacturing requirements, future additional generating requirements will necessarily have to come from non-hydro sources. For the die hard believers in HIC, this leads to the conclusion that adding thermal resources will have a detrimental impact on our rates. For others, this line of reasoning leads to the conclusion that extreme measures may be needed to preserve the northwest's perceived hydro benefits. Measures occasionally mentioned include suspension of the wild and scenic rivers act, the endangered Species Act, and other environmental protections so that we can put hydro facilities in places like Hells Canyon and the main stem of the Salmon River. Other measures include placing limits on the Federal Energy Regulatory Commission (FERC) with regard to subjects that they can consider in their deliberations vis-à-vis the relicensing of existing hydro facilities. But before we take such drastic action, the thermal issue needs to be addressed to determine if it is reality is as bad as its reputation.

To add another twist to the discussion, there are people, generally non-Idahoans and non-northwesterners, that want to open up the electric industry to competition. In the west, California and Montana have already done so. Oregon and others have test programs in place that are seeing varying levels of success. Also, the federal government is contemplating requiring all states to "unbundle" their electric rates. The fear of many in the northwest is that people and businesses in the high rate states will buy up all the cheap energy in the northwest and take it home with them. To resolve most of these problems the question remains, how bad will the impact be?

Finally, while there are often substantial differences between individual utilities full retail rates, the difference in their costs of energy is usually quite small. For instance, retail rates in southern California are as much as five cents higher than northwest retail rates even though northwest wholesale energy prices have probably never been more than 2 cents higher than southern California energy prices. And, for the past several months the situation has been reversed with some northwest wholesale prices higher than southwest prices. This situation is confusing for the HIC believers who can often be heard wondering if the non-northwest prices during this period have been artificially low, and/or if northwest prices have been artificially high.

It was the deregulation issue that precipitated my research and an earlier paper in which I concluded, contrary to my own preconceptions in alignment with the HIC theory, that deregulation would have a beneficial impact for nearly everyone concerned, even people in low rate states like Idaho. Unfortunately, at the time of that paper, there was very little data upon which to rely. The lack of data forced me to construct a rudimentary mathematical model of the northwest electricity market. The model was just complicated enough to be beyond the grasp, and therefore the belief, of the lay public, and just simple enough to be considered incomplete by the technical readers. The model's main problems were; 1, It failed to account for variations in the weather; 2, It assumed pure competition down to the individual generator level, and; 3, That the result of any model, no matter how rigorous, is still nothing more than speculation. The model's main benefits were; 1. It was sufficiently transparent that newcomers to the discussion with only modest economic and mathematics skills could gain an appreciation of the forces at work, and; 2, Simple as it was, the model made surprisingly good price predictions in certain conditions.

I have many friends that are justly proud of their bigger more complicated models of the electricity industry and how theirs use hundreds of equations to calculate thousands of prices for each supply and demand possibility for each second of the day which are then aggregated to form a single, hopefully accurate, price prediction. That is well and good. However, for the purpose of predicting the effect of deregulating retail access to wholesale electrical energy, much of the need for computer models has passed. Retail electricity may still be regulated in Idaho and most other states, but at the wholesale level, competition in the electric industry is in full swing. California passes open market prices directly to their citizens. The BPA pegs their surplus sales to the prices in markets operating beyond BPA's control. Western utilities, including Idaho utilities, are major traders, buying as well as selling, on a full time basis, firm and non-firm energy in various western electricity markets. To determine the impact of deregulation we no longer need computer models. All we need to do is look at current and recent history. A stack of old Wall St. Journals will suffice.

To that end, this paper retraces much of the same ground as my earlier paper with the primary difference being that I have dispensed with the model. For this exercise I have chosen to rely on the historical record. While three and a half years of data is not nearly enough to be considered voluminous, the nature of the data is such that it is sufficient to make general conclusions about how hydro systems, like the ones in the northwest, compare to a more thermal intensive systems like the ones in the southwestern and eastern United States.

With that I will stop boring my readers and get on with the task at hand. I genuinely hope the following discussion is thought provoking and helps in your deliberations.

Sincerely,

Tony Jones

Contents

Executive Summary

1 No matter how well intentioned they may be, citizens, governmental leaders, and utility executives are either misinformed or disingenuous when they claim that the reason for low rates in the Pacific Northwest is due to the benefits of hydro. While the belief may have had a foundation in truth at some time in the distant past, that foundation has ceased to exist.

Full retail rates across the nation continue to span the range from about $0.05 / Kwh in low cost areas like Idaho to about $0.10 / Kwh in high cost areas like California, a difference of about $0.05 / Kwh. However, wholesale energy prices across the nation barely span the range from $0.023 / Kwh to 0.028 / Kwh, a difference of only $.005. The range in full retail electricity rates is 10 times greater than can be explained by the difference in wholesale energy costs. The theory that hydro is cheaper, is a dog that no longer hunts.

2 With open market rates on most of the indexes registering in the low to mid 20 mill range, which is little different than the regulated energy costs in most areas of the country, much of the interest in deregulation, even on the part of industrial customers, has reverted to a cautious wait and see attitude.

Still, even if the magnitude of potential savings resulting from deregulation has decreased in the recent two years, energy cost savings are still possible. Given the differences between peak and off-peak prices, and the price differences between firm and non-firm energy, and the price swings at different times of the year, customers with access to the open market, and the ability to modify the times during which they do or do not purchase their energy, would still find it is possible to achieve savings in excess of 10 percent on their electricity bills, especially in a low cost state like Idaho.

3 Deregulation efforts on the part of high cost states to reduce rates to the levels of their lower priced neighbors are well intentioned but the potential for success is limited. While reducing energy costs is always desirable, the bulk of the difference in rates often resides in the distribution and transmission portion of the bills. Even if the energy portion of electricity bills could be reduced to zero in high cost states like California, they would still have higher rates than many utilities in the northwest.

Once the poles and wires are installed and included in the utility's rate base, the only way to lower the cost / Kwh in any given service territory is for entire customer classes to increase their load factors by consuming more electricity. A second method, merging with another utility that has lower per Kwh distribution and transmission costs would also work. However, barring negligence on the part of regulatory authorities in the lower cost regions, the latter option is not possible.

4 Efforts to protect low rate areas like Idaho from deregulation based on the fear that Idaho's rates will be averaged up to levels like California's are understandable but generally misguided. The primary reason Idaho's rates are lower is because of high load factors that absorb more of the transmission and distribution costs than is common in higher rate areas. Given the near identity of energy costs across the nation, provided current service territories are maintained, Idaho would continue to have the lowest per Kwh electricity rates in the nation regardless of the source of the energy component. Deregulation is expected to provide the most benefit to individuals who are the biggest consumers of Kwhs. Since Idahoans consume more than twice as much energy as people in most other states, it is Idahoans who stand to gain the most by deregulating energy.

Introduction

The main body of this paper presents a review of the available history of prices of energy traded on the open, publicly reported, electricity markets in the United States. Generally, the markets are divided into firm and non-firm markets. Each of these markets is further divided into peak and off peak periods. It varies a little in each market, but firm energy means there is a one hour, or greater, recall provision. The phrase “non-firm” means the power can be interrupted at any time. The firm energy is more reliable, or less risky, and is therefore a little more expensive.

Peak period energy refers to the hours beginning at 7 in the morning until 10 at night, while off-peak is for the 8 hour period beginning at 10 at night running until 7 in the morning.

The data will be presented in a series of charts. Following the charts there will be a brief section pointing out some of the main features of the charts. After that there will be a short section presenting some general observations of how the movements of the various price indexes relate to each other. Finally, there will be a brief section discussing some of the implications that the indexes price histories have for northwest electric energy policy.

Price Targets

Since the discussion deals with deregulation, an overriding issue is how open market prices compare to regulated prices. The average generation costs for the major investor owned utilities operating in Idaho as presented in case number GNR-E-97-1 before the IPUC are as follows;

23.1	mills	Idaho Power Co.,
30	mills	Avista, (Washington Water Power)
32.8	mills	Pacificorp
23	mills	BPA

(Just a reminder, 1 mill is $1/1000, so 23.1 mills equals $0.023)

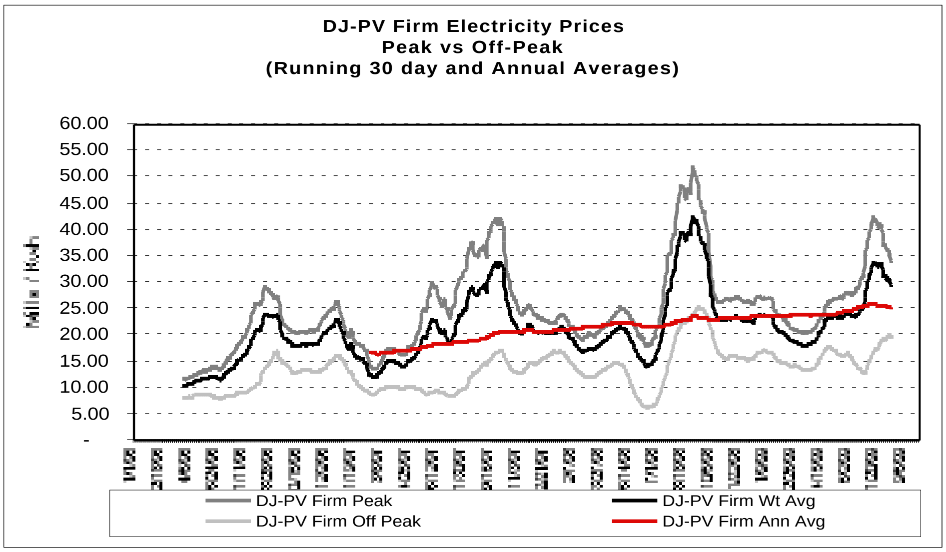
For reference purposes, the full cost of service for these companies, averaged across all rate categories, as detailed in the same unbundling case above, is

42.2 mills for Idaho Power Co.,
50.4 mills for the Avista
63.9 mills for Pacificorp.

Firm Prices

PV Firm

Palo Verde Firm (PV Firm), as reported in the Wall St. Journal is one of the earliest publicly reported indexes of electrical prices in the United States. The chart below displays the entire history of these prices. To smooth some of the more extreme variations, the lines are presented as running 30 day averages. The light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily average weighed by the number of hours in the peak and off peak periods. The red line shows the running average daily price for the preceding 365 days.



Like all of the charts presented in this paper, PV prices have shown a steady increase over the past three years as water conditions have deteriorated. For 1996, PV Firm prices averaged about 16.4 mills / Kwh. For 1997 and 1998 the averages were 20.6 and 23.4 respectively. Currently the average is up a bit more to 24.07 mills / Kwh.

Compared to the main Idaho regulated costs of service, these averages are pretty good. The 1997 average was lower than any regulated energy cost in Idaho. The 98 average was only 0.3 mills above Idaho Power and 0.4 mills above BPA. The current rate of 24.07 mills for PV Firm is 0.97 mills above Idaho Power and 1.07 above BPA. This is also 5.93 mills below Avista, and 7.73 mills below Pacificorp.

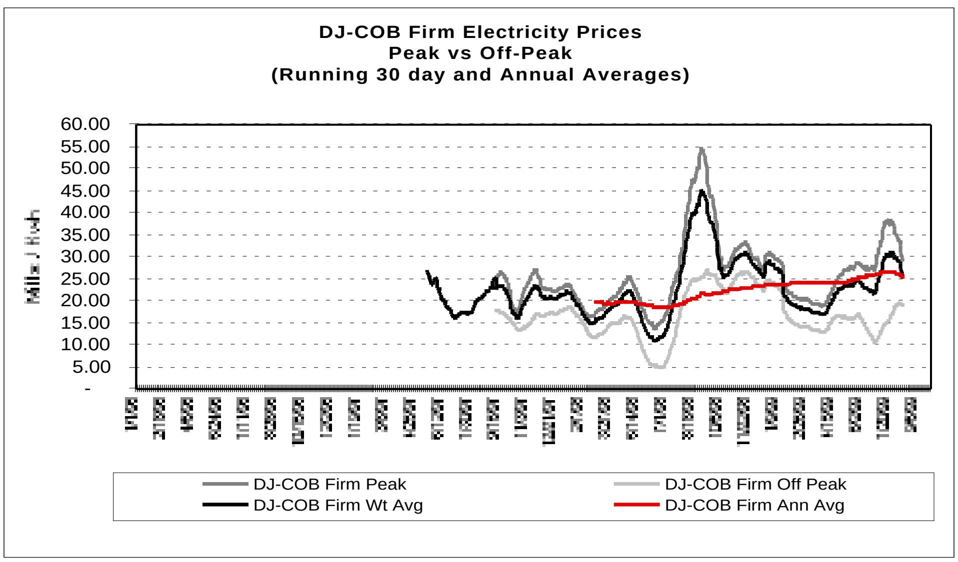
As the graph indicates, there is substantial seasonal and annual price variation. It also shows, that even following an El Nino event in which record high temperatures were reached in southern California as part of a record setting precipitation drought, average annual prices never exceeded 25 mills. The trend is the wrong way of course, however, even by the very high standards of the Pacific Northwest these are very competitive prices.

One interesting part of the PV Firm prices is how consistently low the off peak prices are. Since the inception of the series, the average for off peak energy has been 13.03 mills / Kwh. It regularly drops into the tens and has been as low as 4.9 mills / Kwh. For a price series that has historically been used as a sort of bogey man for northwest electricity consumers, numbers in the low, or even sub, teens must be viewed as something of a surprise.

Another interesting feature is that of price stability. Stable prices are considered a generally desirable goal, particularly if the stable prices also happen to be low prices. While PV Firm prices may not be the lowest in the land, they get high marks for stability. The standard deviation of the average daily price for the PV Firm index is 6.21 mills which is substantially better than the 6.63 standard deviation for COB Firm prices.

COB Firm

California Oregon Border Firm (COB firm) Consistent with the previous section, the chart below displays the entire history of firm prices at the California Oregon Border (COB) as reported by the Wall St. Journal. This index is generally considered to be the index of prices for California north of the Bay area. As this is being written it is also an index that is used as a portion of the California Power Exchange (Cal PX). It is also used, in part, by the Bonneville Power Administration (BPA) to price its surplus firm energy. To smooth some of the more extreme variations, the lines are presented as running 30 day averages. As in the other charts, the light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily weighed average of peak and off peak prices. The red line shows the running average annual price.



As with Palo Verde prices, COB prices have shown a steady increase over the past three years as water supplies deteriorated from above average conditions to average conditions. The COB Firm market did not begin until May of 1997 so no prices are listed for 1996. For 1997 and 1998 COB prices averaged 19.5 and 23.6 mills respectively. Currently, just prior to the beginning of the main spring runoff, the running annual average is up a bit more to 24.6 mills / Kwh.

Like the PV Firm prices, COB firm prices are very close to the best regulated Idaho Rates. The average COB Firm rate in 1997 was below all the Idaho regulated energy costs. In 1998 the average was 0.5 mills higher than Idaho Power, 0.6 mills above BPA but 6.4 mills below Avista and 9.4 mills below Pacificorp. As this is being written, the average is 1.6 mills above Idaho Power, and 1.7 mills above BPA but it remains 5.4 mills below Avista and 8.2 mills below Pacificorp.

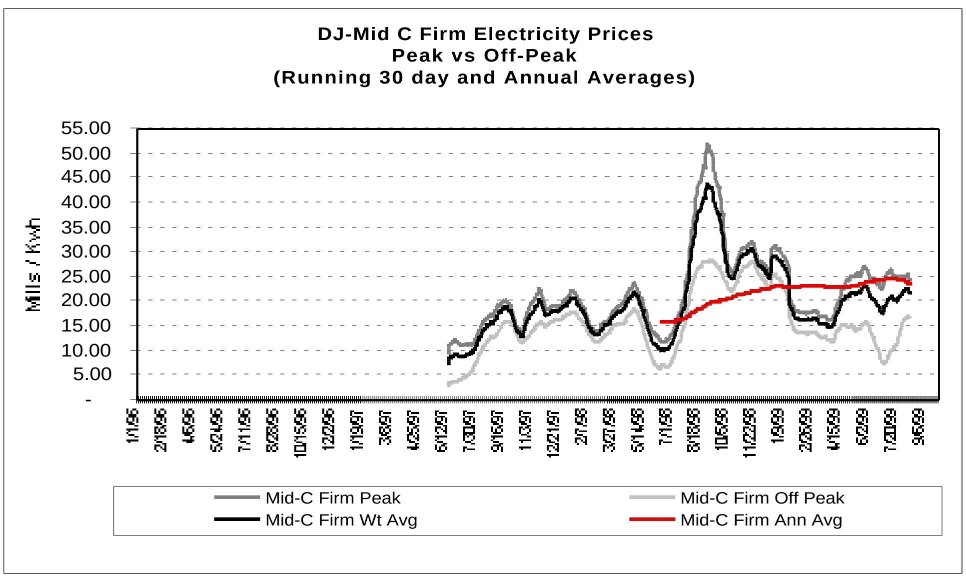
As with Palo Verde prices, there is substantial variation from season to season as well as from one year to the next in this price index. It also shows that even in 1998, a slightly substandard water / temperature year, open market prices will not necessarily exceed existing regulated prices.

Like the other price indexes, COB Firm has displayed some fearsome highs, peaking at 84.5 mills in Sept. of 1998. The index also displayed some tantalizing lows, averaging in the very low 10 mill range for entire months.

If there is a problem with COB Firm prices, it is in the area of price stability. With hydro as the dominate form of generation, high water years bring the potential for very low prices. Unfortunately, when precipitation does not arrive, the alternative is northwest based thermal generation that does not appear to be as economical as its thermal counterparts in other states. This combination of events results in a standard deviation in COB Firm prices of 6.63 mills.

Mid C Firm

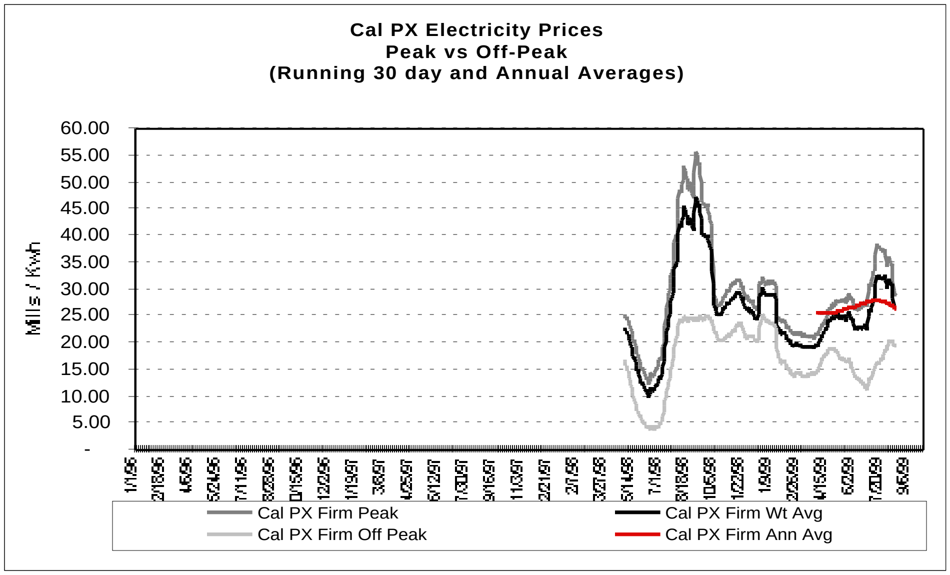
Again, the Mid C chart displays the entire history of closing prices at Mid-Columbia (Mid C) as reported by the Wall St. Journal. This index is generally considered to be representative of prices in Washington, Oregon, Idaho, and western Montana. For smoothing purposes, the lines are presented as running 30 day averages. The light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily weighed average of peak and off peak prices. The red line shows the running average annual price.



For comparison purposes, the Mid C price index suffers in that it has only been reported since June of 1997. However, surprising no one, Mid C is generally the lowest of the four western firm price indexes. For 1998, a year that featured near normal water condition combined with an El Nino summer, the annual average was a scant 22.86 mills / Kwh. As this is being written, the average is up a bit more to 23.3 mills. As mentioned before, this trend is the wrong direction. However, it is anticipated that as soon as the above average snow pack finally begins to fill the rivers, the Mid C prices will descend from the current record high levels.

Cal PX

Like the preceding graphs, the California Power Exchange (Cal PX) chart displays the entire history of closing prices as reported on the California Power Exchange web page. These are the day ahead prices, as opposed to the more recently reported hour ahead Cal PX prices. As such, this series is the most “firm” of the six firm price indexes listed in this section. To smooth some of the more extreme variations, the line is presented as a running 30 day average. The light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily weighed average of peak and off peak prices. The red line shows the running average annual price. Unfortunately, with Cal PX prices being reported since only the beginning of May in 1998, the line representing the running 365 day average is not very long.



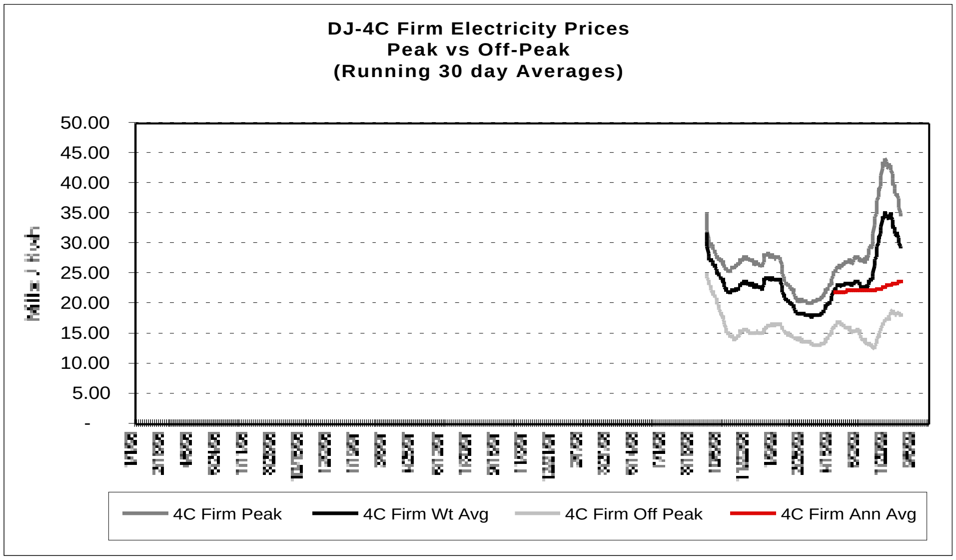
As this is being written, the average price for the last year for the day ahead Cal-PX is 26.27 mills / Kwh. This is a little higher than any other series detailed in this section. However, to the extent that this is a day ahead series, as opposed to a same day series, the risks associated with quoting a delivery price to Cal PX are higher than for other markets and undoubtedly cause prices to be slightly higher.

It is unfortunate that the Cal PX series has not existed longer. As a pass through price for most Californians it would be interesting to compare more than one year of data to the longer data streams for the northwest. While 26.27 mills / Kwh for Cal PX may be 3.1 mills higher than Idaho Power and 3.2 mills higher than BPA, it is 3.73 lower than Avista and 6.53 mills below Pacificorp. The bulk of Idahoans are still receiving electricity service based on lower cost energy. However, it is also true that the bulk of Californians are now receiving service based on lower cost energy than are a substantial minority of Idahoans. As such, the Pro-Deregulation factions in California can legitimately claim to have achieved part of their goal.

While there is far too little data to make any bold statements about the potential of this series, it is clear that price changes on the Cal PX roughly mirror the changes, both in direction and in magnitude, of the other major western electricity indexes. Indeed, because energy markets such as COB and Palo Verde feed directly into the Cal PX, it is a mathematical necessity that Cal PX is influenced by changes in the other indexes.

Another item is that, in California, the Cal PX is a pass through price. Depending on the type of rate schedule offered by the various service providers, residents of the Golden State have the opportunity of tailoring their consumption to the price on any given day. Significantly, while California has deregulated, pricing mechanisms of this type are fully consistent with regulated utilities and have been used effectively in Europe for decades. More on this subject below.

4C



Four Corners (4C) prices are energy prices for electricity that originates near the common corners of SE Utah, SW Colorado, NW New Mexico, and NE Arizona. The lines on the chart follow the same protocol as the lines on the preceding charts. The data for this chart is very limited, it has only been reported since October of last year. Also prices in this market are not superficially relevant to the consumers in the northwest. Still, northwest utilities have previously contracted for supply with utilities in this area in the past, so it is conceivable that northwest businesses and utilities will do so in the future.

4C peak prices have ranged from a high of 41.4 to a low of 12.7. Off Peak prices have ranged from a high of 25 mills to a low of 9 mills. These are prices fully competitive with any of the other preceding price indexes. In fact, if the 4C Firm prices are plotted on the same chart with PV Firm prices, the 4C prices appear to be equal to, or a bit lower, than the previously discussed PV prices. While there is insufficient data to calculate a full annual average, the average for the last nine months has been a modest 21.96. The average for the entire year will probably be a couple of mills higher at about 24 or 25 mills per Kwh. Still, even from this limited series of data, it is clear that low prices and non-northwest generation are not mutually exclusive events.

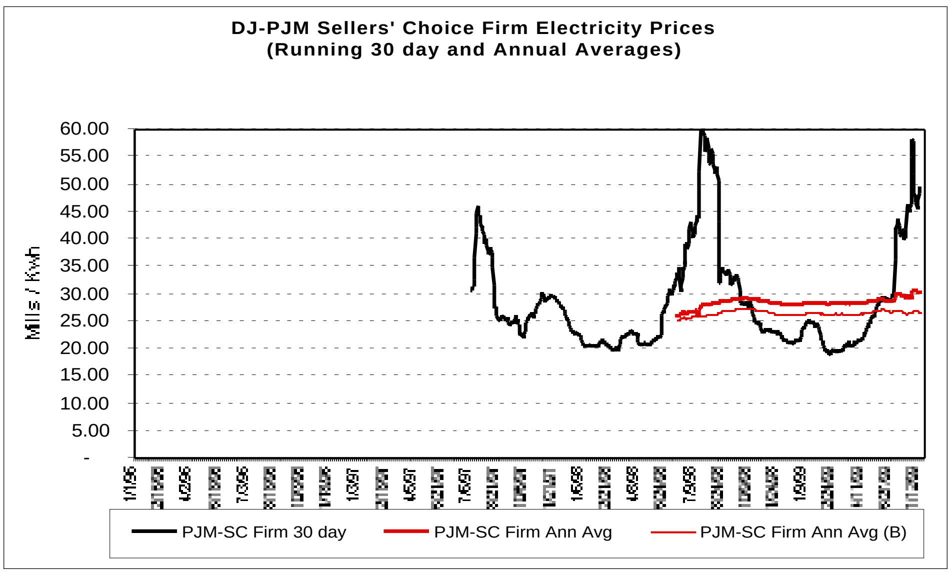
PJM

Pennsylvania, New Jersey, and Massachusetts (PJM) prices are energy prices for electricity along the core of the eastern seaboard. The lines on the chart follow the same protocol as the lines on the preceding charts. The data for this chart is more limited than some of the other charts, having only been reported since July of 1997.

As with 4C prices, prices in this market are not superficially relevant to the consumers in the northwest. The main reason for including this chart is to provide a look at prices in a market that is almost totally thermal based, relies on a high percentage of older power plant technology, and relies on a substantial percentage of high cost coal fuel sources. This combination of production techniques results in a price index that is the highest of any index in the United States. Having said all that, the prices are not particularly high. In 1998 and 1999, average prices in this market were 27.9 and 29.2 mills respectively. This is 4 - 6 mills higher than the regulated rates of Idaho Power and BPA. It is also about 4 mills higher than the COB firm averages for both years.

However, and this is significant, PJM is about 1 - 5 mills lower than the embedded costs of energy in the regulated rates of Avista and Pacificorp!

It is worth mentioning that the PJM system is, by most standards, a tough system to manage. There is a tremendous population base spread over a large geographical area, the weather is unpredictable, there is no good time to take plants off the system for maintenance, and so on. The result is 1-3 day brownouts on the order of once per year



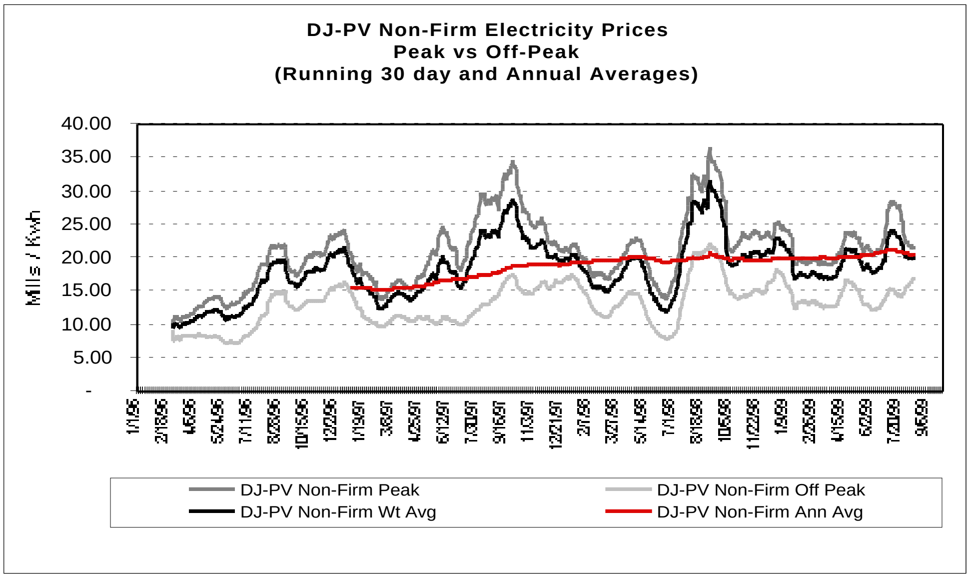
and during the brownouts, prices soar. On the PJM market, daily prices have exceeded 220 mills with hourly rates that are even higher. The reason for mentioning this is that about 3 days per year of brownout pricing are included in the averages mentioned above. If those days are removed from the data, the average PJM prices in 1998 and 1999 are 26.1 and 26.2 mills respectively. Prices of this magnitude are only about 2 mills ($0.002 / Kwh) greater than COB prices for the same periods.

Some may say that, for purposes of comparing PJM rates to western rates, removing the days with brownout pricing is not legitimate. The prices were what they were and by omitting the extreme prices generated during the brownouts presents a situation equivalent to comparing apples and oranges. However, it must be remembered that the western grid had a couple of black/brownouts in 1996. The “official” prices on those days were in the 20 mill range. Realistically, the costs and prices of energy on those days went to infinity. (Any cost or bid price divided by zero Kwh delivered equals infinity.) Since we don’t know how to handle the value of infinity in the averages, the listed price on the western grid on the blackout days is the price of the last observed transaction. As such, there is some extremely high priced energy that is being omitted from the western indexes. This means that, in some respects, omitting the brown / blackout days from the PJM data makes it more comparable to the western data series rather than less so. This is especially so, because in a competitive setting, companies trying to profit from these prices spikes on the supply side, and companies trying to cut costs on the demand side, will both take steps to increase supply and / or get off the grid. Both actions will help smooth the delivery of electricity during peak days which will tend to remove the price spikes from the data. And, as noted above, PJM without the brownout related price spikes is functionally identical to COB.

The Non Firm Energy Markets

The west coast non firm energy markets are among the earliest of the publicly reported energy markets in the country. While energy was being traded by members of the WSCC since the completion of the first northwest intertie, it was not as active of a trading market as the ones described here. And, unfortunately, the trading was not publicly reported. The most significant difference between the firm market and the non-firm markets is risk for the purchaser. Unlike firm energy, the delivery of non-firm energy may be terminated at any time. As such, the non-firm markets, except for the occasional exception, operate at a substantial discount relative to the firm markets.

PV Non-Firm



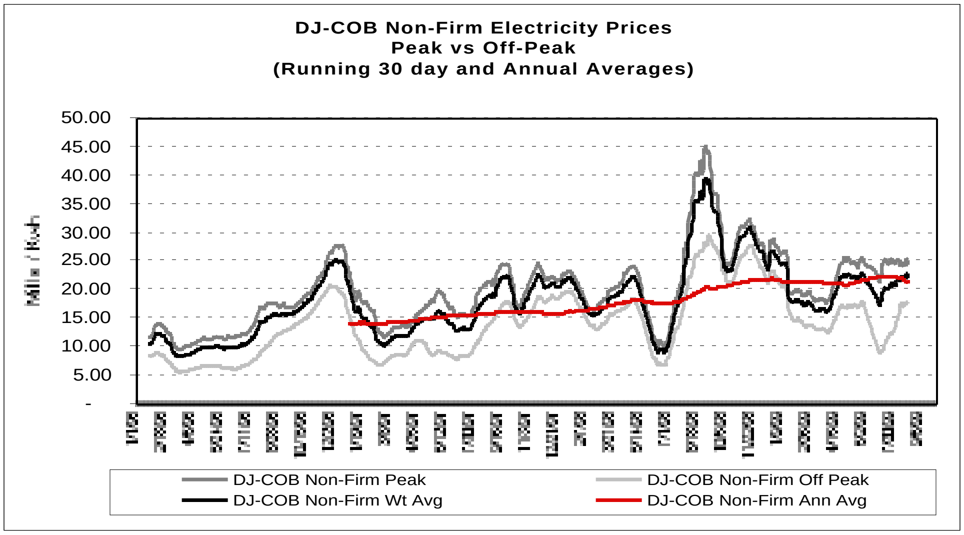
Beginning in March of 1996, the Palo Verde Non-Firm (PV Non-Firm) market has been reported longer than all other western price indexes except the COB Non-Firm market. This chart displays the entire history of closing prices at Palo-Verde as reported by the Wall St. Journal. The lines are presented as running 30 day averages to smooth some the day to day variations. As in the firm charts above, the light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily weighed average of peak and off peak prices. The red line shows the running average annual price.

Like the firm energy, the non firm energy prices display substantial seasonal and annual price variation. It also shows that, for individuals that can handle the risk of interruption, non firm energy can be a real bargain. At the end of the 1998 El Nino event that produced a record setting drought in southern California, average annual prices for PV Non Firm never exceeded 21 mills. As this is being written the PV prices for the last year have averaged a modest $0.02016 / Kwh. For 1996, 1997, and 1998 the prices were even more impressive at 15.29 mills, 18.88 mills, and 19.73 mills. Since 1996, Pacificorp's prices have been between 12.5 and 17.5 mills higher. Idaho Power's energy costs are closer, but have still been between 2.8 and 7.8 mills higher over the same period.

Let there be no mistake, the non firm market is no place for the faint of heart. For one day in 1998, peak hour prices averaged a soaring 113 mills. That is 11.3 cents / Kwh for just the energy component. However, as frightening as the highs may be, there are times when the prices are surprisingly low. It is not uncommon for peak and off peak prices to drop into the single digit range. The record low one day average for PV Non Firm off peak energy is 3 mills while the record low for the corresponding peak energy is 7.9 mills.

The range of prices displayed on the PV Non Firm market are extreme, but at the same time, it is a reasonably predictable market. To date, the running 365 day average for this market is the most stabile of any of the publicly reported indexes, firm or non-firm. Total variance in the annual average, from the beginning of the series to current is 5.36 mills. Over the slightly shorter time period of September of 1997 to current, the total range of the running 365 day average has been a scant 2.5 mills.

COB Non-Firm



Once again, the chart below displays the entire history of closing prices at COB as reported by the Wall St. Journal. For smoothing purposes, the lines are presented as running 30 day averages. The light gray and dark gray lines represent the off-peak and peak prices respectively. The black line shows the daily weighed average of peak and off peak prices. The red line shows the running average annual price.

This graph also shows the now familiar seasonal and annual price movements. Annual averages prices have ranged between 21.8 mill and 13.8 mills. As this is being written the COB price average for the last 365 days is $0.02158 / Kwh. For the years 1996, 1997, and 1998 the averages are 13.8, 15.8, and 21.7 respectively.

Like the PV market, the COB Non Firm market is home to wild price swings with a one day peak high price of 98.1 mills and a one day off peak low price of 2 mills. For the last year COB non firm has been about 1.5 mills less than the Idaho Power cost of energy, 8.4 less than Avista, 11.22 less than Pacificorp, and 1.42 less than BPA.

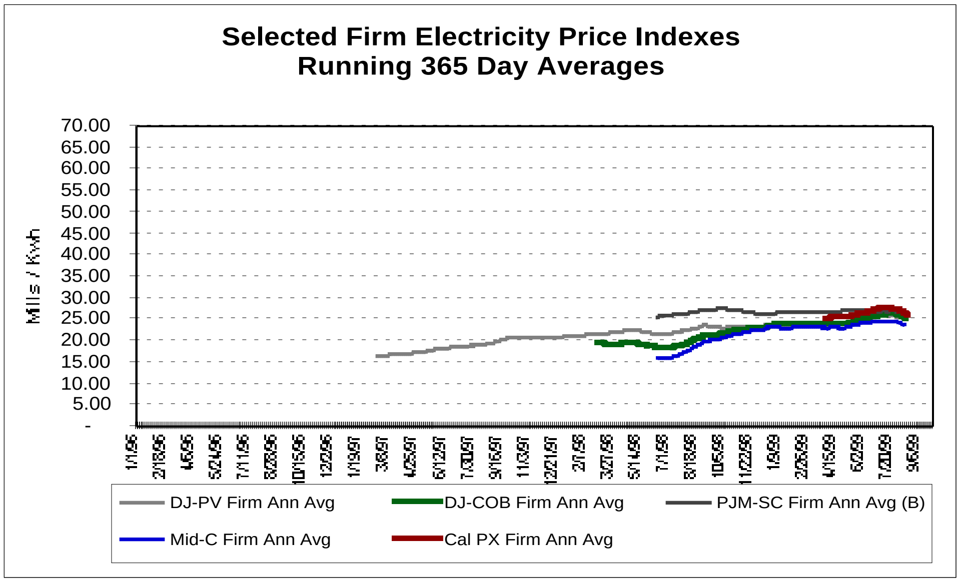
Where the COB Non Firm distinguishes itself from the PV Non Firm market, is in the area of price stability. The PV Non Firm market is the most stable of all the western energy indexes while the COB Non Firm index is the most volatile. The COB index shows more variability from one year to the next, and it also shows more variability from one season to the next within individual years. The exact reason for this event is unclear, but a prime suspect is the annual variability in the generating capacity of the hydro units.

Mid C Non-Firm and 4-C Non-Firm

The Mid Columbia and Four Corners markets both have non-firm components that are currently being reported. Unfortunately, the reporting of both series began quite recently. As a result there is not enough data to make any meaningful comparisons with the other price indexes. In the event that this paper is updated at some future time, these price series will be included as appropriate.

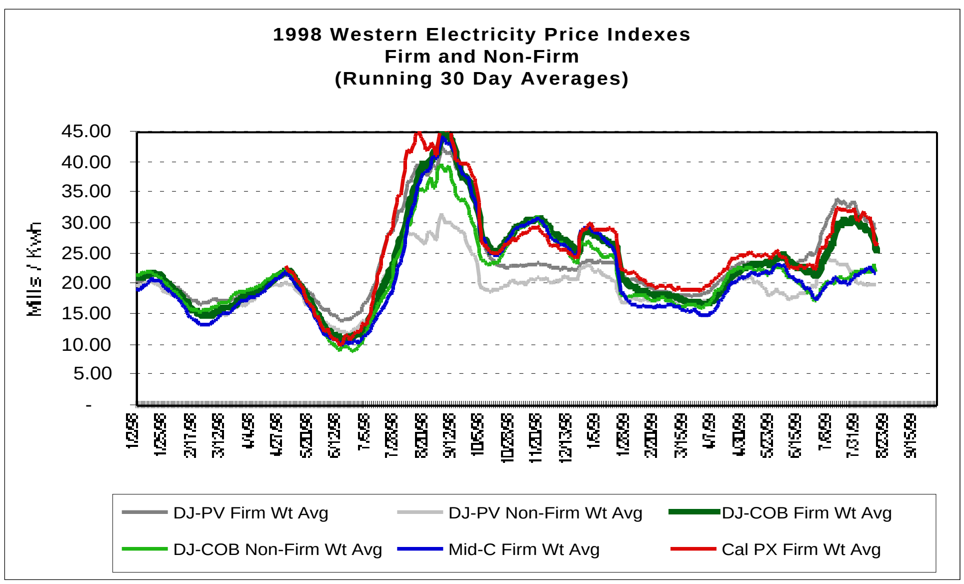
General Observations

Composite Chart



The chart on the right displays the running average annual prices of firm price indexes. The lines included here are the same as the annual averages included in each of the preceding graphs for the relevant individual markets. They are repeated in this format as a means of more easily showing how prices in each of these categories compares with the equivalent prices in other categories.

Timing



All western firm prices series move in the same general direction, and in the same general magnitude, at about the same points in time. (Please see the accompanying chart.) That is to be expected. The seasons are the same, and the weather conditions are roughly the same for most of the western United States. It is natural that, while there are day to day differences, the general large scale swings in demand, and to a lesser extent supply, will all move in the same direction at the same time. The main difference is that the extremes in the swings in demand and supply are often larger for the northwest than they are for the southwest. This is particularly true in the winter. In the inland northwest there is a winter peak in energy demand associated with space heating that is much less evident in the southwest.

Price Trends

With only three years of data, all of which is associated with successively worse water / weather conditions, it makes sense that each western index displays an upward slope. To say much more than at this time would be premature. However, given the amount of precipitation deposited in the mountains of the northwest this winter, it is only reasonable to expect prices to start declining as soon as the delayed spring runoff begins in earnest.

Price Levels

Currently, following the end of a slightly worse than normal water / temperature year, the average price of all the major firm price indexes are nearly identical. The difference between the lowest price index, Mid C, and the highest price index, Cal PX, is a scant 2.85 mills. If Cal PX is overlooked on the basis that it is in a sense "firmer" than the other firm indexes, the total price difference is even smaller. The difference between Mid C on the low end and COB Firm, next highest after Cal PX, is only 1.19 mills. In English, that is $0.00119 / Kwh. For a typical, 1200 Kwh / month, Idaho customer the difference is only about $1.42 per month. Perhaps more surprising is that Mid C Firm, the core index for the northwest, is only 0.73 mills ($0.00073 / Kwh) less than PV Firm, the core index for southern California. If the difference were passed through to an average Idaho residential customer, the loss of "the hydro advantage" would amount to less than the cost of a Sunday paper, about $0.90 per month.

Averages and Weighting Factors

Various interested parties will critique the averages used in this report for manner in which they are, or are not, weighted.

The Dow Jones and California PX daily price indexes are weighted averages. The weight factors are the sales volumes that occurred at various prices.

The daily averages used in this paper are weighted by the amount of consumption on an hour by hour basis for the peak and off-peak prices. The combined daily average price is weighted 66.7% peak, and 33.3% off peak. This is because peak pricing represents 16 hours each day and off peak pricing represents 8 hours per day. As such, the price histories listed in this report are partially un-weighted prices.

This is also true for the annual averages detailed in the preceding graphs. No period of the year is given any higher weighting factor than any other period of the year. The annual averages are a simple average of the consecutive 365 prices observed in the various energy markets.

It would have been simple enough to weight by the Idaho aggregate daily loads, or some other standard, but for every group that the chosen weight factors match, there would be dozens of other groups for whom the weights would be incorrect. Every industry, every utility, every business, every farm, and every individual has their own unique set of weights. The purpose here is not so much to show exactly how one person or group would benefit, or be injured, by open market prices but rather to show what prices to expect at various time of the year in one market relative to another. As such, the primary requirement is to use the same weighting factors for each series. Choosing weighting factors that are relevant to different sectors of the economy would presumably be interesting to the affected parties, but it adds very little to broader discussion.

Convergence.

For the first 10 to 12 month of the public reporting of these price indexes, COB Firm and PV Firm prices were separated by 2 - 3 mills. At that time, some commentators considered the difference as being the result of the northwest's predominantly hydro, hypothetically cheaper, generation sources. However, beginning in about July of 1997, the COB and PV Firm markets began to converge. By about November of 1997 the convergence was complete and since that time there has been no significant difference between the two series. In fact, for most of the last two years, the running 365 day average price on the COB Firm market has been higher than the corresponding PV prices. As this is being written, the average for COB for the last year is 21.63 while the average for PV is 21.04. The difference is admittedly small, however, as little as a year ago, daily variances in this direction were considered to be an oddity. Variances in this direction that might last for an entire year were considered to be highly unlikely.

Also of interest is how close the Mid-C price index is to the PV index. For the first year it was reported, Mid C was a full 6 mills lower than PV Firm. However, from about mid 1997 to the beginning of 1998 Mid C soared while PV stayed flat. The result is that since January 1998, Mid C Firm and PV Firm prices have generated annual averages that have paralleled each other, separated by only about 1 mill.

Implications

1 Convergence, Collusion, and Competition

The convergence of all the major western price indexes into a group whose prices are very close to each other is statistically real. Subsequent to this convergence, there have been voices, usually on the demand side of the industry, that wonder, given the tepid downward price response to the recent wet winter and spring, if current open market energy prices, particularly northern energy prices, should be lower. Some think the prices are legitimate but remark that, "It is a different market than it was a couple years ago." Others are more cynical and claim that, "The market is fixed."

While the convergence is statistically real, it may or may not be statistically abnormal. With only about 4 years worth of publicly available data, describing 4 different water supply / temperature conditions, associated with markets that in some cases have only recently come into existence, covering a number of states, the largest of which recently deregulated, it is difficult to determine what is statistically "normal" for any of the indexes. In the absence of an unarbitrary estimate of "normal", it is equally difficult to determine if the markets are behaving abnormally. This is especially true when the phrase "abnormal prices" is used to mean prices consistent with the HIC theory, a theory that has little or no statistical support. So, even though it may be desirable to believe the market is rigged as a way of explaining surprisingly high northwest prices, the evidence is just as strong, probably more so, that the market is responding in a rational manner.

For instance, theory would suggest that, given open access to cheaper northern energy, which northern energy was by a small margin when these indexes were first published, buyers from traditionally expensive areas would be expected to shop in the traditionally cheaper markets, take home relatively more of the cheap power, and in the process prices of the formerly cheap power will be driven up until, transmission capacity willing, prices in the two markets achieve parity.

Generally, this appears to be what has occurred. While there has always been trading among the members of the western grid, it has traditionally been at a lower intensity. Historically, a variety of technological and regulatory constructs stood in the way of trading being as active as it has become in the last few months. This got in the way of operational efficiency as well, with total transfers on the north-south grid typically running at lest than 25% of capacity. This year, traffic headed south on the main north - south interties is running at about 60% of capacity. Historically, annual shipments have averaged 25,310 Gwh The record is 36,421 Gwh set in 1985. Year to date volume for 1999 is 15,216 Gwh and if it continues at this rate for the rest of the year, there will be a near record of 30,854 Gwh shipped south.

So, the market appears to be working in a smooth, logical, consistent fashion. And, all the indexes are displaying prices that closely mirror each other. The problem with this result, in some eyes, is that for it to be true we are left with the conclusion that northwest energy, hydro energy that is, is not substantially cheaper than southwest or east coast non-hydro, energy. This was/is a scary thought when the 5 cent difference in rates between California and Idaho was/is blamed on California having much higher priced, non-hydro, generators.

There is evidence to suggest that northwest energy has never been substantially cheaper than southwest energy. For instance, for the first full year of data on the COB and PV non-firm markets, when people thought the north-south price differentials were "about right", PV averaged 15.27 mills while COB averaged 13.83 mills, a scant 1.44 mill difference. This one data year is not a definitive indicator of past price differentials, but it is about as good as we are going to get with publicly available data. It may be that, given weather and water conditions that year, both indexes were as much as 10 mills lower than for a normal year. However, there is no evidence that the southern California index was, then or now, as much as 50 mills below normal relative to the northwest indexes. 50 mills is of course, the amount of differential between northwest costs and southwest costs that is necessary to explain a 5 cent difference between California and northwest retail electricity rates if the difference is to be explained by differences in generation costs.

Currently, as the barriers to trading are increasingly eliminated, as information dissemination improves, as various other types of trading friction are eliminated, it is only natural that all the interconnected price indexes should approach each other ever more closely.

But, what about collusion, is there any evidence? If there was price collusion between major energy suppliers, wouldn't the markets "look" like they were operating appropriately?

These are a troubling questions because, as previously observed, information dissemination about all market activity is much more common and effective than it has been in the past, and the prices of the various indexes are, on average, very close together. However, these observations are not prima facia evidence of collusion. Evidence of collusion would involve things like northern and southern markets moving in unison, or in close parallel, for a substantial number of hours and a substantial number of days. A review of the empirical evidence reveals no overwhelming evidence of such actions.

However, even if there is no sign of collusion, that does not mean that we have well functioning markets either. Economics books generally hold out the prospect of pure competitions as the system that will naturally deliver the right service to the right people at the best prices. For pure competition to work it is generally thought that there needs to be many buyers and many sellers interacting in a market for relatively homogenous products and services. However, when there are sufficiently few sellers or buyers, or when one seller or buyer becomes sufficiently large as to be able to dictate the structure and the results of the market, the cost minimization provision of pure competition begins to erode.

Clearly, with several hundred generating facilities located throughout the west, each selling colorless, tasteless, nameless, homogenous electrons, the potential for pure competition exists in the electricity market.

However, it is just as clear that in the western grid, as much as 75 percent of several individual wholesale markets are controlled by as few as one or two generation companies. These same energy marketers are also utilities with their own captive customer base and, in states where the generating companies have been separated from the distribution companies, there has been little or no attempt to limit the market share of individual generation companies. Finally, since most of the west is still regulated, there are very few “consumers” operating in any market. To top it off, issues related to transmission services need to be resolved before additional marketers have any realistic chances of success. In light of these operational issues, it should come as no surprise that pure competition is not being practiced in the western energy markets.

The current situation does not involve monopoly activity per se. Also, it does not appear to involve price collusion either. However, when several markets are completely and thoroughly dominated by a few large generation companies and a few large purchasing companies, we should not be surprised if open market prices are higher than expected.

As a parting comment, it should be noted that even at the high point of the three documented data years, even in the presence of combined oligopolistic and oligopsonistic markets, all of the series are about equal to, or below, the regulated prices of every major utility in Idaho. One can only wonder if the prices wouldn’t be substantially lower if we were watching real competition at work.

2 How High is High?

Given that all the northwestern price indexes trend upward with time, it is reasonable to wonder if there is any upper limit. First it is worth noting that these are nominal prices. That means that there is a little bit of inflation in the prices. Inflationary effects probably account for about 0.2 mill per year. Of the 10 mill increase in COB from the mid teens to the mid twenties, between 0.6 and 0.8 mills may be attributable to inflation. So, about 90 percent of the increases we see in the graphs are real increases.

Also, as mentioned before, in each successive year presented in these charts, the precipitation / temperature combination has gotten progressively worse until, possibly, this year. That means progressively less water, and progressively more thermal based generation which presumably means higher costs and presumably higher prices. Assuming still worse water / temperature conditions, prices could be expected to continue upward. If, hypothetically, the regulated energy costs represent the norm, and the mid-teen annual price indexes from the early period of the prices shown here represent the effect of successive years of above normal precipitation, successive years of drought could drive prices for the existing western and northwestern mix of generation technology up to about 35 mills.

Having said that, there is ample reason to think that prices could not be sustained above the current level on a long term basis. The reason this can be said with some certainty is that, if we breached every dam on every river in the west, and bought out and moved west enough of the dilapidated thermal plants from the Pennsylvania - New Jersey area to make up the difference in generating capacity, our energy prices should not exceed the current PJM prices that are consistently in the sub-30 range. If we take this tack and manage them as well as we do our current system, and thus avoid the persistent brownouts experienced in the east, we should be able to supply all of our needs with the questionable eastern thermal generators at an open market rate of about 26 mills. This would be within about a mill of Idaho Power’s current generation costs and would be cheaper than Avista and Pacificorp.

From another angle, state of the art gas turbines are being installed in various parts of the country with the owners anticipating that they will receive their full rates of return at average price levels as low as 23 mills. Lower prices will deter additional investment while higher prices will stimulate investment.

Significantly, all of the west coast market indexes are already very close to the 26 mill point, even Mid-C. This state of affairs should give our elected and appointed governmental leaders, as well as the management of northwest utilities, cause for concern. If our vaunted hydro based electrical generation system cannot consistently and substantially outperform gas fired plants or the admittedly aged and inefficient east coast thermal systems, it is time to reevaluate whether it is worth the subsidies, the broken treaties, and the degradation of the river systems and fisheries associated with its continuance.

3 Threat of Northwest Electricity Rates being Driven Up by Out of Region Demand.

A recurring fear among individuals and policy makers is that if the NW electric industry is deregulated, Californians will buy up all our ostensibly cheap electricity and we poor weaklings in the northwest will lose the "benefits of Hydro." The fear is that we will end up paying the same elevated electric rates as Californians, and that our economy will stagnate and die.

While there may have been some historical foundation for this belief, current fears of such an event are totally unfounded. For the past 17 months, there has been is no significant difference between California electricity prices and Pacific Northwest electricity prices at the generation level. That is the bad news.

The good news is that the southern California rates are lower than most regulated northwest rates and about on par with the best northwest energy prices, regulated or unregulated. To the extent that consumers in these areas see rates 40 - 50 mills higher, it is for reasons other than generation costs. For more discussion on this issue please see Appendix 1 below.

In the absence of any substantial difference in wholesale energy prices between the northwest and the southwest, there ceases to be any reason for Californians to buy substantial amounts of northwest power. Provided northwest states continue to regulate transmission and distribution, the fear of our prices being driven up, or being averaged up, by mixing with California prices is groundless.

4a Transmission Concerns

For those who persist in fearing the insatiable demand in the southwest, and fearing that all the energy in the northwest will be shipped south, there are other problems that make such an event unlikely. One is that, even if northwest utilities are desirous to ship all their power out of state, they can't sell something they can't deliver. In other words, unlimited energy exports require unlimited transmission capacity. Such capacity does not exist.

The BPA records show that the greatest amount of energy transferred from the northwest to systems in California was 36,421 Gwh set in 1985. The ten year average has been substantially lower at about 25,310 Gwh. While it is possible that a new record for energy exported south will be set this year, the grid is currently running at about 60% of capacity for the year, there is no indication that the transfer is causing energy shortages or exorbitant open market prices in the northwest. There is also no indication that, with current north-south price parity, there is any desire to move higher levels of electricity to the south.

As for exporting electricity to the east, it is currently impossible in any but the smallest of volumes. The ability of northwest utilities to export to any region of the country other than California or British Columbia (who traditionally exports to us), is less than 1% of total generating capacity.

In short, northwest utilities will continue to have their normal demand to contend with, plus some California demand that at times will equal whatever capacity is available on the southbound transmission lines. That amount will vary. However, both theory and observation indicate that the impact of out of region demand on northwest capacity and prices, barring major revisions to the grid, will continue to be small.

4b Potential for Increased Export Transmission Capacity

Some Californians would like to see additional transmission capacity from the demand side, and that northwest utilities would like the same thing from the supply side, is not doubted. Just as there are many people in the northwest who mistakenly assume that California energy is more expensive than northwest energy, there are many people in the southwest who mistakenly assume the very same thing. These advocates of building additional transmission will have tremendous political muscle. Whether or not they can overcome the combined resistance of conservationists along the route, as well as irrigators, businesses, and residents of Washington, Oregon, and Idaho with a vested interest in keeping their power "at home" remains to be seen. Under no circumstance will the siting, certifying, and installation of transmission in excess of minor upgrades to the current system be either quick or cheap.

At the same time that the transmission line advocates will be pushing their proposals, gas companies, gas turbine companies, fuel cell companies, co-generator developers, wind farm developers, photo voltaic developers, demand side conservers, and others will be pushing forward as quickly as possible, eroding, and in many cases eliminating the demand for energy that the transmission line advocates intend to supply. At this point, given the near identity of prices between northern and southern California, it appears that the alternatives to additional transmission are winning.

Finally, in 20 years, both the northwest and California will be out of capacity. In the absence of effective distributed generation systems such as domestic fuel cells, construction of new base load plants will have to begin in 5 - 10 years. After that point, in a competitive environment, it will be the marginal producers, the new plants, that set the price of power, both in the northwest and California. There is every reason to think that these new plants will have very similar costs wherever they are located. This means that then, as now, prices in the northwest will probably be very similar to the prices in California for reasons independent of transmission. Then, as now, it will make no sense, and there will be no financial reward associated with building more transmission lines for the purpose of exporting additional power to the south.

The only scenario that leads to the conclusion that more transmission is desirable is one in which, perhaps 40 or 50 years into the future, gas is exhausted and coal becomes the fuel of choice. In this scenario, mine-mouth thermal (coal) plants located in Wyoming, Montana, and the southern Rocky Mountain states may become the marginal producers. That scenario will require a substantial amount of east-west transmission capacity.

4c Potential for North - South Retail Rate Parity

As discussed ad nauseam above, much of the political posturing north of the California-Oregon border involves actions designed to protect and maintain the "Benefits of Hydro" for people in the relevant northwest states. Absolutely none of the posturing has dealt with the possible effect on the northwest's economy of California having retail electricity that is cheaper than the electricity in the northwest. Absurd as it may seem, this result is a real possibility.

The previous paragraph was written nearly two years ago. As this is being written, the possibility mentioned above, is coming to pass. For large customers getting their energy directly at the transmission level, it has been possible for California customers to match northwest energy prices for the last 17 months. It seems to be an emerging truth that for large customers, the difference between northwest and southwest energy rates, one way or the other, will never again be very large.

Of particular note is that, for large customers in deregulated states willing to change the mix of their energy purchases, such as using firm energy during peak hours of peak seasons, and using non-firm energy at night during peak season and at all hours during low demand seasons, the potential to undercut northwest energy rates is real, and substantial. For these customers, the energy price advantage of locating in the northwest has vanished.

5 Excess Capacity - Time of Day Rates, etc.

By the standards of most business, even seasonal businesses that strive to keep excess capacity under 15%, most regulated utilities, including those in the northwest, typically have surplus capacity that amounts to about 30% of the total. One of the reasons for this situation is because electricity is so hard to store. A high level of reserve capacity is required because it is very difficult, ie. very expensive, to build electric inventory in advance.

Having said that, it must also be stated that an additional reason for the need for such high levels of reserve capacity is the result of flat rates. In a regulated setting, except for a few larger customers of a few utilities, customers pay the same rate, night or day, weekend or mid week, peak season or non peak season. Thus, in peak season, when demand is high and when supplies are short, when the cost of generating electricity exceeds the rate being charged, there is no incentive for customers to conserve.

If, on the other hand, for some customers, electric rates were allowed to fluctuate with the cost of production, as happens in most unregulated industries, it is only reasonable to assume that the higher peak season rates would induce some customers to conserve, which would reduce demand, which would reduce the need for a substantial amount of excess capacity, which would ultimately reduce rates.

It is not a concept that is appetizing to everyone. However, for consumers who have the ability to change the time of day when the bulk of their energy consumption occurs, such as putting timers on the water heater or doing the irrigation pumping at night, it is an option that has the potential to provide savings to both consumers and service providers alike. It is also a concept that has the potential to provide benefits in a regulated, or unregulated industry.

6 Benefits of Competitive Pricing

As little as two years ago there was substantial in interest in deregulating the electric industry in Idaho. This was particularly true for large industrial customers. The reason for the interest was annual average open market wholesale energy rates that were as low as 15 to 17 mills. Now that the open market rates of most of the indexes are registering in the low to mid 20 mill range, which is little different than the regulated rates, much of the interest on the part of the industrial customers has reverted to a cautious wait and see attitude. It is hard to blame them for their change in attitude.

Still, even if the magnitude of potential savings has decreased, energy cost savings are still possible.

a, The average price of COB and Mid C over the last three years is 22.21 and 19.68 mills / Kwh respectively. Compared to the best investor owned regulated rate in Idaho, this is a difference of between 0.89 and 3.42 mills / Kwh. If the open market rates had been passed through to Idaho retail customers, the total savings over the last three years would have been between $38.45 and $147.74. For the roughly 300,000 Idaho retail customers the combined savings would have been between $11 million and $45 million.

b, In the section on weighted averages several paragraphs above it was noted that the prices presented here are unweighted prices. While remembering that, and looking at the differences between peak and off-peak prices for firm and non-firm energy during different times of the year, it should be obvious that, if a customer had access to the open market, and decided to modify the times of day during which they do or do not purchase their energy, and were allowed to change their mix of firm and non-firm energy during different times of day and different seasons of the year, it is possible to substantially lower the average price of energy, even during the highest priced periods of the year.

For instance, the peak for energy consumption and prices is generally from the early afternoon through early evening. Any consumer with open market access who is willing to restrict their consumption between 3:00 PM and 5:00 PM, thus avoiding the "peak of the peak", could see energy cost reductions from a 50 mill residential rate of as much as 10%. During the summer, if the same consumer was willing to restrict their consumption to the hours between 7:00 PM and 10 AM, thus confining their consumption to the off-peak hours, could see energy cost reductions of as much as 17%.

There are many alternatives to this process that involve different consumption times of the day, different days of the week, substituting non-firm energy for firm energy, especially during off-peak hours, et cetera. The point is, that for individuals for whom energy costs are a major consideration, the open market continues to offer substantial opportunities for cost savings relative to the existing regulated rates.

c, Investment to cover the peak moment of demand is a substantial amount of most utilities generating investment and thus contributes substantially to the magnitude of their energy rates. Any mechanism that encourages customers to conserve during peak periods, even if it is at the expense of greater consumption during off-peak periods helps reduce the level of required peak capacity which reduces the amount of total investment and improves the system's load factor both of which combine to reduce rates.

As mentioned before, the flat rates used for most of Idaho's regulated rates do nothing to encourage people and business to avoid energy consumption during peak periods while time of day rates have been shown to be a very effective method of getting consumers to help smooth aggregate consumption patterns. Time of day rates and other load shifting mechanisms are a product that competing service providers offer almost as a matter of course. Similar products offered by at least one electric cooperative operating in southern Idaho has found excellent acceptance among the irrigator class.

With ever increasing information technology, consumers in every walk of life have come to expect ever increasing levels of customer service. Load shifting mechanisms as a method of saving costs for consumers and utilities alike is an idea whose time has come. It is a common service in deregulated territories. It is a service that should be encouraged, even for regulated utilities, as a means of increasing load factors and decreasing the need for new generation resources.

Appendix 1

Regional Rate Disparities. Some thoughts on why California rates are higher.

Most people know that Californian's have traditionally had higher priced electricity than do people in the northwest. Most people assume it is because the northwest is hydro based while the southwest is thermal. While that may be a factor, the bulk of the difference is more mundane. To help explain, a brief analogy may help.

Suppose you have an uncle Calvin and an Aunt Ida. They both work as sales representatives for the same printing company. The company leases each of them identical brand new Ford Taurus sedans for $300 per month apiece and the company reimburses them for their gas. During an annual review of the auto fleet, an accountant notes that Ida's car is costing the company $0.29 per mile while Calvin's is costing a whopping $0.54 per mile. What's the deal? Is Calvin wasting the company's money by buying gas that is twice as expensive as the gas Ida gets? Calvin is in big trouble, right? The boss asks Calvin to explain.

It turns out that Calvin is not in trouble. He keeps excellent records, gets 30 miles per gallon of gas, that he buys for $1.20 per gallon, of which he buys $24 worth a month. His total auto costs are $324 per month. By comparison, Ida also gets 30 miles per gallon of gas but she is less scrupulous and pays $1.25 per gallon, of which she buys $50 worth a month. Her total auto costs are $350 per month.

But, wait a minute. If Ida's total costs are higher, how can her cost per mile be lower than Calvin's? The trick is in the number of miles they drive. Calvin's sales route is shorter and he only drives 600 miles per month. Ida on the other hand travels 1200 miles per month. Calvin buys less gas, and gets a better price on the little gas he does buy, but the cost per mile for his car is higher than the cost per mile for Ida's car because he drives fewer miles. For Calvin the equation is $324/600mi = $0.54 per mile, while Ida's equation is $350/1200mi = $0.29 per mile. The denominator in the fraction "$ / mile" is much smaller for Calvin's car which makes the resulting number bigger. It is the same mathematical process that makes the fraction 1/4 smaller than 1/2.

Now, back to California. California is known to have electric rates as high as $ 0.10 / KWH while the rates for many Idahoans are about $0.05 / KWH. The traditional justification for the difference is the notion that hydro generation is cheaper than thermal generation. Let's see if the traditional justification holds up to scrutiny.

Much of the cost of electricity is associated with fixed costs. The poles, the meters, the service drops, the distribution lines, the transmission lines and the generator installations are all fixed costs. Generally, these costs are very similar wherever they are located. The physical installation and the associated fixed costs necessary to supply a 200 amp box on the side of a house in Nampa, Idaho is very similar in scope and cost to the physical installation necessary to supply a 200 amp box on the side of a house in Mission Viejo, California. The only way to lower the per KWH cost of fixed cost items such as these is to run more power through them more of the time. If the lines are below their carrying capacity, the $/KWH cost of the system decreases by one half every time the number of Kwh's is doubled. It is just like driving more miles in the car example.

Most houses in the west have similar peak electricity requirements, both in and out of

California. Therefore peak system capacity on a per capita basis is similar, both in and out of California. However, since California is further south the sun shines a greater portion of each day which diminishes the need for area lighting. Also, California winters are less severe than those in states farther north which diminishes the need for winter space heating. In a nutshell, while California and the northwest states have similar per capita peak system capacity requirements, ie. investment requirements, Californian's run less than half as many Kwh's through their system on a per capita basis. It follows directly that with only one half of the KWH's being used to absorb the same per capita fixed costs, the fixed part of a Californian's bill, on a $ / KWH basis, will be twice as high as an Idahoan's.

The following tables help detail the issue.

Electric Energy Sales (Billion KWH)

	Pop	Total	Res	Com.	Ind.
Id	1,099	19.0	5.7	5.3	7.6
Wa.	2,255	89.3	28.4	18.7	38.3
Or	3,032	42.9	15.2	11.8	15.1
Ca.	31,211	213.4	68.1	80.2	57.1

Per Capita Electric Energy Sales (million of KWH)

	Total	Res	Com	Ind.
Id	17.2884	5.1865	4.8226	6.9154
Wa	39.6009	12.5942	8.2927	16.9845
Or	14.1491	5.0132	3.8918	4.9802
Ca.	6.8373	2.1819	2.5696	1.8295

Ratio of Other States Per Capita Consumption to California Consumption

	Total	Res	Com	Ind.
Id	2.5285	2.3770	1.8768	3.7800
Wa	5.7919	5.7721	3.2272	9.2838
Or	2.0694	2.2976	1.5146	2.7222
Ca.	1.0000	1.0000	1.0000	1.0000

Source, U.S. Energy Information Administration

For example, as detailed in the table below, if Idaho Power's system were in California where per capita consumption is 40% lower, (1 / 2.3770), the $48.48 that represents the fixed monthly charge for the power supply, transmission and distribution accounts for $0.0404 of the $0.052 / KWH residential rate. However, if the same $48.48 is divided by 505 KWH per month instead of the Idaho Power average of 1200 per month, the rate for the fixed components increases to $0.096 per KWH. If we then add the variable components, at exactly the same $/KWH rate as Idaho customers are charged, it brings the total up to 107.73 mills / KWH, or $0.10773 per KWH. Significantly, this yields a rate very similar to those seen in California.

Average Consumption (KWH / Mo.)	
Idaho 1200	California 505

Impact of Per Capita Consumption, (Load Factors) on Electricity Rates

		Idaho Power Rates*			Idaho Power Rates with Calif. Per Cap. Cons.		
		Avg. Unbundled Cost per Mo.	Mills Per KWH	% of Tot	Avg Unbundled Cost per Mo.	Mills Per KWH	% of Tot
Power Supply	Var.	$11.04	9.20	17.7%	$4.64	9.20	8.5%
Power Supply	Fixed	19.44	16.20	31.1%	19.44	38.51	35.7%
^ Mkt CSPP	Fixed	(2.52)	(2.10)	-4.0%	(2.52)	(4.99)	-4.6%
DSM	Fixed	(0.60)	(0.50)	-1.0%	(0.60)	(1.19)	-1.1%
Delivery Losses	Var.	3.00	2.50	4.8%	1.26	2.50	2.3%
Transmission Fac.	Fixed	3.96	3.30	6.3%	3.96	7.84	7.3%
Distribution Fac.	Fixed	17.17	14.31	27.5%	17.17	34.02	31.6%
Metering Fac.	Fixed	2.54	2.12	4.1%	2.54	5.04	4.7%
Customer Sys.	Fixed	8.28	6.90	13.2%	8.28	16.40	15.2%
Other	Fixed	0.20	0.17	0.3%	0.20	0.40	0.4%
Total		$62.52	52.10		$54.39	107.73	

*Source, Idaho Power Co. Unbundling Filing.

In conclusion, while there are some differences in power supply, transmission and distribution costs that help push prices in other regions higher, much of the difference is attributable to lower per capita consumption and the resultant lowered ability to absorb fixed costs. As long as Idaho and other northwest consumers continue to use electricity more intensely than people in other regions, the extra KWHs consumed will continue to absorb a greater portion of fixed costs and our rates will continue to be lower. This is true whether or not energy is deregulated.

Just as in the case with Calvin and Ida and their cars, where it was not enough to look at just the final $/mile figure, it is not enough to simply look at the final $/Kwh numbers. The numerator is important, but no more so than the denominator.

As a parting shot, in both the automobile and the utility examples, it is the low cost / mile person and the low $ / Kwh regions that stand to gain the most by seeking cheaper energy sources. This is so because for the low cost sectors, the energy portion is larger, both in actual and in percentage terms, than it is in the high cost sectors.

Appendix 2

Costs vs Prices

One of the better pro regulatory criticisms of an early draft of this paper questioned whether I was confusing costs and prices. The point is concerned with the prices in the indexes detailed above which are market prices while the regulated rates, some of which are also listed above, are based on costs.

First, a short diversion. Regulation is all about recovering costs which are well documented during the rate making process. Competition is all about recovering value which is a much more subjective concept than cost. Indeed, value can be substantially higher, or lower, than operational costs. Theory and practicality suggest that long term competitive prices must reflect production costs but this is not necessarily so in the short term. For this reason, some people wonder if Palo Verde, 4-C , PJM and other non northwest price indexes are capable of remaining at current “low” levels for the long term. First, if PV costs are higher than COB, COB producers should be able to successfully compete and increase profits by cutting their prices slightly and selling into the PV region, particularly when there is both substantial excess COB capacity and substantial excess north to south transmission capacity. The fact that COB producers have failed to do this for nearly two years suggests that PV costs are similar to, and perhaps lower, than COB costs. Second, there are several coal fired plants in the pacific northwest that have individual regulated rate of return revenue requirements (R5) in the sub 25 mill range, even with poor load factors. There is no reason that plants with similar technology and better load factors in the southwest and the east coast cannot operate at similar cost levels, or even lower. Third, state of the art gas plants are currently being contracted and built with expectations of operating profitably in a 23 mill price environment. This means that 25 - 26 mill prices may be too high in the long term. Fourth, it is a perfectly reasonable business tactic to sell older technology energy at new technology prices of about 23 mills or lower in an effort to deter additional competition. The practice may mean reduced returns for the existing producers, but reduced returns are much higher than the alternative, which is no returns. In summary, it may not be certain but it is at least possible, even probable, that the prices currently displayed in the non-northwest price indexes cover the costs and modest profits for the relevant suppliers.

Now, back to what I think was the critic’s main point. The question as to whether I am confusing prices with costs is typically the prelude to a discussion that runs something like, “In competition we have to accept prices that we can’t control. With regulation, we can control the costs and thereby control the prices. Shouldn’t we fight like badgers to keep the big low cost hydro projects inside our own territory of control so we can use them to average-down our aggregate generation costs and thereby continue to have lower cost electricity than other areas?”[1]

This of course is just a variant of the regular HIC theory. And, as mentioned previously, some of the bigger, older, hydro projects <u>do</u> produce electricity very inexpensively.

[1] This line of reasoning completely neglects the fact that in competitive markets participants are able to control prices through the mechanism of long term contracts. Indeed, in most respects, a regulatory body is little more than a contracting agency delegated to represent people in a certain geographical region.

And, those projects do average down the costs of other less cost effective resources. The problem is that while some of our predecessors successfully traded a variety of public assets associated with northwest river systems for some of the most locally cost efficient hydro electricity in the world, some of their successors squandered the benefits of these same hydro facilities by averaging their costs up with less productive assets like the WPPSS nuclear plants, most PURPA projects, and many other projects in the regulated resource stack that have R5 costs well in excess of 23 mills. They may have done it with the best of intentions but the result is a regulated hydro based system in the pacific northwest that includes so many high cost projects in the mix that the few low cost hydro projects are no longer capable of keeping the northwest's regulated average prices below the open market prices in other regions, regardless of their means of generation. It is that sort of "cost control", or more accurately lack of control, that gives regulation a bad name.

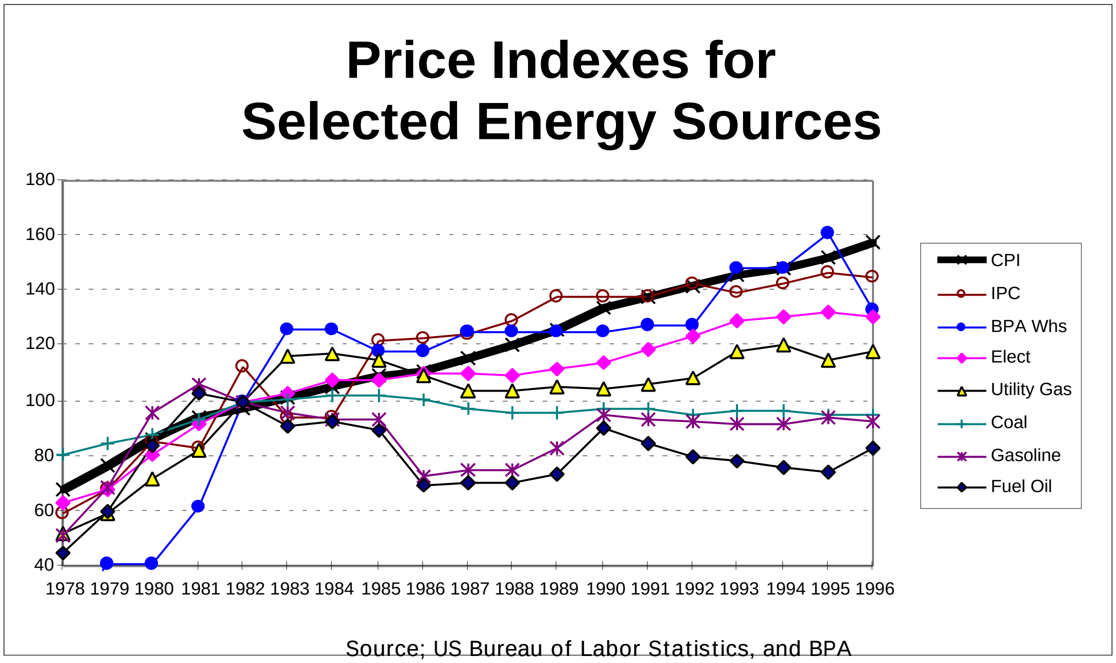
Many people look at full retail prices as continuing proof of the HIC theory. That is faulty reasoning. (For an explanation with more depth, see Appendix 1 above.) The method of generation has no impact on transmission and distribution costs which typically account for 50 - 80 percent of total retail rates. For an accurate determination of the viability of the HIC theory one must look strictly at generation level energy prices. And, as mentioned before, anyone looking for a 5 cent difference in wholesale energy costs as a means of explaining a 5 cent difference in retail rates will not find it. The HIC theory does not work at the generation level. And, if the HIC theory does not work at the generation level, it does not work at all.

To be fair, the HIC theory may have had some basis in fact several years ago. It probably didn't account for a 5 cent difference in retail rates, but it may have accounted for a 1 or 2 cent difference. And, it is theoretically possible for the HIC theory to work at that level again. However, if it is to ever work again, even at a modest level, some changes will be required in the manner in which we regulate the utilities. For instance;

> **a Resolve Past Mistakes.** No matter how well intentioned the projects were when they were authorized, most northwest utilities are dragging around, and rate payers are paying for, a number of projects whose costs are substantially higher than market prices. The WPPSS nuclear projects, many PURPA projects, and a smattering of thermal plants, were terrible investments. In a competitive industry they would have been written off years ago. No matter how low the cost of some of the big hydro projects, the weight of these latter mistakes is too much to be carried and have the complete system still display costs consistent with the HIC theory.
>
> The problem is that, because the regulatory agency authorized them, the only way of de-authorizing the high cost projects necessarily involves some form of stranded cost payment or other public buy-out that will be just as costly as keeping them on the books.
>
> **b. Avoid Further Dilution of the "Hydro Advantage".** In other words, don't authorize additional projects that will have the effect of elevating future system average costs above future open market prices. Yes, this describes what the regulators presumably already try to do. And, to successfully know the long term result of every decision requires omniscience on the part of the regulators. No one said the jobs were easy.

The trouble is, the past performance of most electric regulators on this point is rather poor. The graph on the following page displays the prices of a variety of energy forms normalized to be directly comparable to the consumer price index.

Averaged across the nation, fuel oil, gasoline, and coal were all cheaper through 1996 on a nominal basis than they were in 1980. Adjusted for inflation they are all currently selling for about 1/2 the price they were in 1982. Utility gas fared a



little worse, inflating rapidly between 1982 and 1984. Since 1984 however, utility gas prices have remained constant. Interestingly, the foregoing are all energy forms that are not directly regulated.

At the top of the chart is the CPI and three electricity indexes. Of all the energy price indexes, the two that have exceeded the rate of inflation more frequently than any other are those of BPA and Idaho Power Co., the two most commonly extolled as exemplary by believers in the HIC theory. In fact, BPA and Idaho Power energy prices have been increasing faster than the national average electricity price. Interestingly, the three electricity price indexes, the three indexes on the graph that have increased most rapidly, are the only three whose retail prices are directly regulated.

If the past is any indication of the future, regulated electricity prices will continue rising faster than other non-regulated forms of energy. Unfortunately, when northwest regulated electricity energy prices are already functionally equivalent to the open market electricity prices, higher rates of inflation in the regulated energy sectors is not acceptable.

This section and the one previous combine to illustrate a fundamental difference between competitive markets and regulated ones. Firms in competitive markets have a simple method of eliminating inefficient projects. They “write them off.” They take the loss and get back to business. Competitive markets are free to charge anything they want but they do so at the peril of attracting additional producers to the market, many of whom will use the latest technology and offer lower prices than the established producers charging excessive prices. This process tends to keep prices down.

In cost based regulated markets, while the utilities may be restricted in the amount they can charge, mistakes in the form of ill advised investments still happen, and about the only way to eliminate inefficient power plants from the rate base is old age. If you wait long enough, in some cases half a century, high cost plants, some that are rarely operated but continue to earn a profit for the utility, will finally depreciate themselves into oblivion. If the proponents of regulation ever want to deliver a truly low cost product, they must devise a better way of removing the results of previous investment mistakes from the rate base.

Appendix 3

Hydro Relicensing

In the next decade, most of the lowest cost hydro projects in the northwest will have to be relicensed. The problem is that in the course of the relicensing proceedings the Federal Energy Regulatory Commission, (FERC), is duty bound to consider issues that were often not considered as relevant when the original licenses were issued. These issues range from the relatively simple issues such as boat ramps and other public facilities on the reservoirs, to more contentious issues such as changing the manner in which the facilities are operated. Some groups will want the operation to maximize recreational benefits while others will want to minimize environmental damage. Another issue that will come up for some hydro facilities is the possibility of retrofitting the dams with fish ladders and other facilities for the purpose of reestablishing migration paths for fish that were eliminated when the dams were originally constructed. Some issues will be mandated by FERC while others will not. Some of the mandated issues will be sufficiently inexpensive as to be inconsequential. Others issues will be sufficiently expensive as to draw into question the continued existence of many projects. This latter possibility has already occurred several times in across the nation in recent months.

This is the point where the road forks depending on whether the industry in question operates in a regulated environment or whether it operates in a competitive environment. The reason the road forks here is because of the fundamental difference in which companies function in the two markets. The differences are laid out most simply in the two following equations;

Open Market	**Profit = Revenue - Cost**
Regulated Market	**Revenue = Cost + Profit**

From the perspective of open market prices in a deregulated industry, relicensing is largely a non-issue. Competitive prices are determined by the marginal operating costs of the mix of individual plants that comprise the entire industry while most of the potential modifications to an existing hydro facilities will not even change the marginal cost operating parameters of the hydro facility in question. The modifications will affect the return on the investment for the plant being relicensed but that is the concern of the owners. It is not the concern of the customers. If the required modifications are sufficiently extensive (costly) that the operating company feels it is less costly, (more profitable), to decommission the facility, that is the prerogative of the owners. Any facility that cannot compete will, indeed should, be replaced by facilities that are competitive.

The situation is fundamentally different in regulated industries. While in deregulation few, if any, relicensing costs get passed on to the final consumer, in regulated industries most of the costs get passed through to the final consumer. Remember, “cost based” regulation means “cost plus” operation. If the FERC’s conditions for relicensing require modifications to a dam, the utility has the choice of modifying the dam, or decommissioning it and finding alternative sources of energy. Either result will be more costly than the operation of the existing asset. The utility then takes the receipt for the chosen action to the appropriate regulatory body, who then adds in the appropriate profit margin and authorizes the company to increase its rates accordingly. (The average system cost for any utility is the result of some low cost assets offsetting other higher cost assets. Replacing a low cost resource with one or more higher cost resources necessarily forces the resulting average cost to be higher.) It is a little more complicated than that, but not much. Whether the modifications are minor or extensive, inexpensive or very expensive, most relicensing costs become the obligation of the captive rate payers.

It would be nice to know how much relicensing will affect rates for any given regulated utility. Unfortunately, while it is possible to describe a matrix of potential problems and costs associated with projects that are due to be relicensed, and estimate the impact on various company's rate bases, it is impossible to foretell what FERC's determinations will be for the various projects. The only thing that is certain is that the impact on retail consumers will be greater if the system is still regulated than it will be if the system has been deregulated.

In summary, the dilemma for consumers is this; Is it better to keep regulation in place in the knowledge that, while rates will remain constant for a few years, they will necessarily be forced up as the big, low cost hydro projects are relicensed? Or, is it better to deregulate now, and face the uncertainty of open market prices that may or may not be lower than current regulated costs, in the knowledge that most costs associated with relicensing will be avoided?

Appendix 4

Hydro, the “Clean” Energy Source

Once upon a time the claim that electricity was “the clean” energy referred to the fact that using it in the home was cleaner than the alternative gas lamps, oil lanterns, and coal furnaces. Now that electricity has captured almost the entire lighting market and since any modern furnace is as clean as electric heat from an in home airflow perspective, the phrase “electricity, the clean energy” has moved from the consumption side to the production side. In particular, it is now often claimed that hydro projects are a “clean” method of generating electricity.

If the definition of “clean” is limited to mean the absence of smoke emissions, then the statement is true. Otherwise, hydro projects generate a variety of pollutants that are often the match of any thermal plant.

First, the word pollution in this context simply means unwanted operational by-products. Economists often broaden and soften the discussion slightly by using the term, externality. The term externality is used with the understanding that, potentially, operational by-products can be either beneficial or detrimental. For instance, waste heat generated by traditional thermal plants is normally considered to be detrimental. However, waste heat from these plants is increasingly being captured and used to increase the operational efficiency of the generating plant itself or used in the manufacturing processes of neighboring industries. In this case, some of the waste heat is considered to be a positive externality.

The traditional list of externalities includes things like smoke, soot, smog, noise, toxic liquid effluent streams, waste heat, and oxides of nitrogen, carbon and sulfur emitted into the air. With hydro, the externality list includes things like water flow disruptions, seasonal water temperature disruptions, fish migration disruptions and siltation. There is also the disruption of traditional free flowing river based recreation activities and the possible enhancement of still water, reservoir, type recreation activities. These types of externalities are perhaps more subtle than the traditional “smoky” externalities, but they are no less substantial. The smoky externalities cause multiple health problems for humans, animals, and plants and may be partially responsible for global warming. Hydro sourced externalities displace humans and animals, disrupt ecosystems, sometimes enough to kill some plants and animals, and may be partially responsible for global warming.

As the argument rages vis-a-vis the degree of responsibility of the dams on the lower Snake River for disrupting salmon migrations, even the most ardent supporter of hydro projects must admit that the dams bear some of the responsibility. In the case of other hydro projects, such as Grand Coulee on the Columbia, Swan Falls and others on the Snake, Diversion and others on the Boise, and Black Canyon on the Payette, the responsibility for eliminating salmon runs in part of their respective drainages is complete. Taken individually, the various damages to the fisheries seem unfortunate, but manageable. Taken as a whole on the Columbia-Snake River drainage, hydro projects are responsible for the equivalent of an Exxon Valdez tanker crash each and every year.

Ironically, there is one externality that is unique to hydro facilities in that it attacks the very system itself, siltation. Siltation is the insidious process by which all reservoirs fill up with silt, ultimately rendering the facility useless. Some reservoirs are silting up faster than others, it depends on the nature of the river and whether there are other reservoirs upstream collecting the bulk of the silt. But, sooner or later, each dam will be turned into a waterfall by the siltation process. The resultant project, by virtue of the vertical drop, may still be able to generate some electricity, but it will increasingly be reduced to a run of the river facility with ever decreasing ability to store water from season to season or to control floods.

Society's alternatives once the dams are gone and/or the costs associated with the disposal of several million cubic acres of mud is a subject that is rarely discussed. In most cases the problem won't have to be faced for several generations. However, it may ultimately become as difficult and costly of a problem as the decommissioning of nuclear reactors.

The discussion could continue further but the point has been made. No matter how strongly a person feels that the existing hydro network is justified, under no circumstance should anyone think of hydro as being free of negative externalities.

Appendix 5

Approximate Operating Costs of Selected Western Generation Projects

Plant #	Co.	Project-	TotalAnn ReqRev.	Long Term ReqRev perKWh	Short Term ReqRev perKWh	NetGeneration kWh
51	IPC	Horseshoe Bend hydro	789,486	0.04579	**0.04579**	17,241,000
175	IPC	Hells Canyon	8389550.551	0.00337	**0.00054**	2,486,939,000
176	WWP	Noxon Rapids	12056670.04	0.00655	**0.00066**	1,839,638,000
178	WWP	Cabinet Gorge	6963855.867	0.00611	**0.00081**	1,139,942,000
180	IPC	Brownlee	17146698.95	0.00571	**0.00085**	3,004,328,000
186	IPC	Oxbow	6901977.653	0.00561	**0.00116**	1,230,228,000
187	PAC	Clearwater #2	1184622.253	0.01733	**0.00119**	68,358,000
192	PAC	Copco #1	784196.4978	0.00824	**0.00195**	95,226,000
195	WWP	Monroe Street	3277781.613	0.04377	**0.00275**	74,890,000
196	IPC	CJ Strike	3383091.147	0.00690	**0.00283**	490,015,000
200	IPC	Twin Falls	4454383.053	0.04278	**0.00342**	104,129,000
202	IPC	Swan Falls	7558917.476	0.05344	**0.00363**	141,458,000
212	IPC	Shoshone Falls	964860.8222	0.00962	**0.00590**	100,336,000
214	IPC	Cascade	2656209.764	0.05565	**0.00642**	47,733,000
215	IPC	American Falls	7316279.071	0.02040	**0.00682**	358,598,000
248	PAC	Hunter #2	45653111.06	0.02222	**0.01201**	2,054,693,000
251	PAC	Colstrip	35494103.8	0.03569	**0.01287**	994,561,000
256	PAC	Hunter #3	95829330.39	0.02834	0.01312	3,380,858,000
275	PAC	Jim Bridger	235005049.5	0.02267	0.01435	10,367,115,000
277	WWP	Colstrip	47655502.62	0.04000	0.01446	1,191,402,000
289	IPC	Jim Bridger	110511325.3	0.02489	0.01556	4,439,166,000
296	PAC	Naughton	113737663.1	0.02383	0.01687	4,772,109,000
299	PAC	Centralia	77238801.63	0.02516	**0.01878**	3,069,611,000
318	IPC	Valmy	43879131.83	0.95055	**0.22798**	46,162,000

Source; FERC Form 1’s