Back to the New Market Basics

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"Any Mistake Worth Making Once Is One Well Worth Repeating"

Any truly successful evangelical philosophy needs a set of primary aphorisms so simple and so evocative that they can be taught quickly and easily. Karl Marx contributed "from each according to his ability and to each according to his need" and almost conquered half the world. Alfred Marshall proposed "price equals marginal cost" and succeeded.

The reason why P=MC is so seductive is that it promises that open markets will also be efficient. Any statement that provides both wealth and freedom from governmental intervention is going to have wide appeal. Competitive market proofs of the rule are easy to find. Until the advent of the California ISO, this rule was even true in the Western Energy Coordinating Council reliability area.

Looking Backwards

At the turn of the 19^{th} century, Thomas Edison and his backers faced a problem in the application of price theory economics to the provision of central station electricity. Central stations were terribly expensive. In fact, they were so expensive that they were virtually impossible to finance given uncertainty of demand. The situation was so dour that Thomas Edison's company actually went into bankruptcy.

The solution was to implement cost plus regulation to guarantee that the central stations were financeable. Like any simple solution, it soon spawned unforeseen consequences. The guarantee was so strong that it encouraged excesses in utility financing. The architect of cost plus regulation in most of the U.S. and Canada was the man of his age, much as Ken Lay is today. After several years in Cook County Jail, he was released in 1934 when the government proved inadequate to the task of prosecuting him for a variety of financial misdeeds.

The problems were largely solved by the establishment of the Securities Exchange Commission and the passage of the 1935 Public Utilities Holding Company Act.

On the operational front, the guarantees were so good that efficiency was not an important part of plant construction. The capital costs of new generation reached astronomic levels –

$4,000/kW in the late 1970s and early 1980s. The passage of PURPA in 1979 provided a fix to that problem. Off the shelf natural gas generation could be installed for $500/kW. The lower capital prices more than offset higher fuel costs.

Many of us, including myself, were overjoyed by the proof that unsophisticated PURPA developers were able to deliver working generating units at a lower cost than regulated utilities. The incentives offered by an open market proved themselves a thousandfold during the 1980s. The price signal provided by California's enormously high central station costs of the regulated utilities was so seductive that California ended up with an unintended side effect – a massive surplus for California.

Advent of the Wholesale Power Market

The same logic created the nascent wholesale power market in 1981. Peter Johnson, the Administrator of the Bonneville Power Administration at the time, decided to start selling the agencies' surplus short term energy to the highest bidder – breaking a forty year tradition of allocating inexpensive short term supplies. This inadvertently brilliant decision bootstrapped a large wholesale power market. Since BPA also offered open access transmission, utilities from San Diego to Alberta were able to buy and sell electricity at "Mid-Columbia." Thus, Mid-C became the world's first trading hub for electricity.

The next fifteen years were the heyday of bulk power markets. BPA provided open access to utilities, generators, and industrials. A vast amount of hidden capacity was unleashed as major industrials found direct incentives for cogeneration and the sale of underutilized generating capacity. Prices plummeted. FERC graced the market with temporary market pricing in 1988 and permanent approval in 1991.

Almost by chance, we found ourselves in a perfect greenhouse for competition. BPA, the only market participant with the size to assert market power, chose a relatively passive stance as a matter of political philosophy. Other sellers were small compared to the size of the total market. In California, purchasing was dominated by three large buyers, so the major market dysfunction tended towards oligopsony – many sellers/few buyers.

Plant dispatch decisions became relatively simple. Plants were dispatched on a weekly or monthly basis reflecting the difference between market prices and operating costs. Price discovery was easy – so easy that nothing more than a telephone was required to trade electricity. Entry and exit was so easy that the easily received FERC marketing license was the only entry requirement.

Enter California's Romance With Centralized British Markets

One of the ironies of electric competition is that California noticed the plummeting prices and carefully drew the wrong conclusion. England had adopted a very different model of electric generation after the Second World War. Instead of promoting a large number of individual utilities, they nationalized the industry. Their objective was job preservation – the coal industry in England was the driving political objective. By the late 1980s England had accomplished creating the least efficient industry in the world. Outages were frequent, prices were high, and employment was astronomical.

The British solution was to establish a central governmental agency to administer a centralized market. While the centralized market was liberal compared to the institution that preceded it, it was a severe step backwards in the United States. One of the unfortunate lessons of the California restructuring is that RFPs before 1998 – the advent of the AB-1890 structure – received more responses than after the markets had been "created."

After the advent of the California ISO and the California PX, prices went up and reliability fell. While a centralized market was a liberalizing concept in England, it was a step away from open markets in the WECC.

Barriers to entry in California were, and still are, ferocious. Paula Green, the power manager of Seattle City Light, estimated that the administrative costs of serving Seattle City Light commercial customers in California were 10% of total delivered costs. At one point an internal ISO memo noted that Pacific Gas and Electric, one of the world's largest utilities, was too unsophisticated to manage the congestion management techniques at the ISO.

Where Are We Now?

The ISO's motto "Better Reliability Through Markets" is also seductive. In spite of the problems in California, FERC has encouraged the adoption of the centralized British model across the U.S. and Canada. Although FERC's missionary zeal has abated a small degree over time – at one point FERC proposed that three RTOs would dominat~~ed~~ the entire industry – the reality is that prices are now largely determined in centralized markets. Areas characterized by open markets, like the Pacific Northwest, have come to reflect the opportunity cost of sales and purchases from their centralized neighbors, like the California ISO.

As a general rule, the new markets are opaque and amazingly complex. Also, as a general rule, RTO operations are secret. The computer programs and the all important algorithms are deeply confidential. Actual prices are generally public, but the calculations behind them are understood only by industry insiders.[1]

[1]ERCOT is the defining example of computational opacity. Real time prices are calculated by a confidential algorithm loosely based on linear programming. Computational failures are common – so common that ERCOT has adopted a "duct tape" policy for repairing the prices when the algorithm fails. At least twice this year the algorithm has returned prices above $80,000/MWh. The only detailed descriptions of the algorithm can be found on the University of Peking web site.

In spite of the press releases describing participation in the new markets as being dominated by doctorates in chaos theory, the discovery in civil and criminal cases coming out of investigations in Texas and California reveals that market participants have little understanding of the underlying economics. Technical analysis is relatively primitive.

Price formation is consensual rather than analytic. This is not necessarily a bad outcome. A central role of trading is the transfer of information. The absence of sophistication does not make price discovery any less valuable.

One result of the complexity, opacity, and lack of sophistication of the centralized markets is that questions of efficiency are harder and harder to evaluate. We know that prices in Texas and California seem high, but we no longer know quite how to compare the prices to alternatives.

When prices anomalously spiked in Texas last year, the insights given by one of the market leaders to a counterparty exemplified the current state of the art:

> Holden Salisbury: "TXU, this is Holden"
> Norm Bertheson: "Hey Holden, Norm Bertheson at Cirro?"
> Holden Salisbury: "Yes sir."
> Norm Bertheson: "Anything happening here in some of the short term power?"
> Holden Salisbury: "Um, it's not looking too good right now. I don't think I'm going to have anything to offer."
> Norm Bertheson: "Nothing available?"
> Holden Salisbury: "I just don't have anything…"
> Norm Bertheson: "Where's all the energy going?"
> Holden Salisbury: "It's cold man."
> Norm Bertheson: "I mean, it is, but hell, nobody's at work. Very few people. I mean…"
> Holden Salisbury: "I don't know."
> Norm Bertheson: "Strange. Strange how we can have 56,000 available in the summertime and we can't get 40 together in the wintertime."
> Holden Salisbury: "Yea. I don't know. I mean there's units that are down in the state."
> Norm Bertheson: "What units are down?"
> Holden Salisbury: "I don't know but I know there are some. Look, I've gotta go man."
> Norm Bertheson: "Alright."[2]

Holden Salisbury's quick exit from the uncomfortable question seems well suited to explaining the state of the art today. When hard questions are asked, everyone leaves the room.

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[2]TCE Second Amended Complaint, February 3, 2004, page 162. Holden Salisbury, a graduate of Enron's infamous Western Power Trading office, is explaining why none of his enormous portfolio of resources was for sale that day.

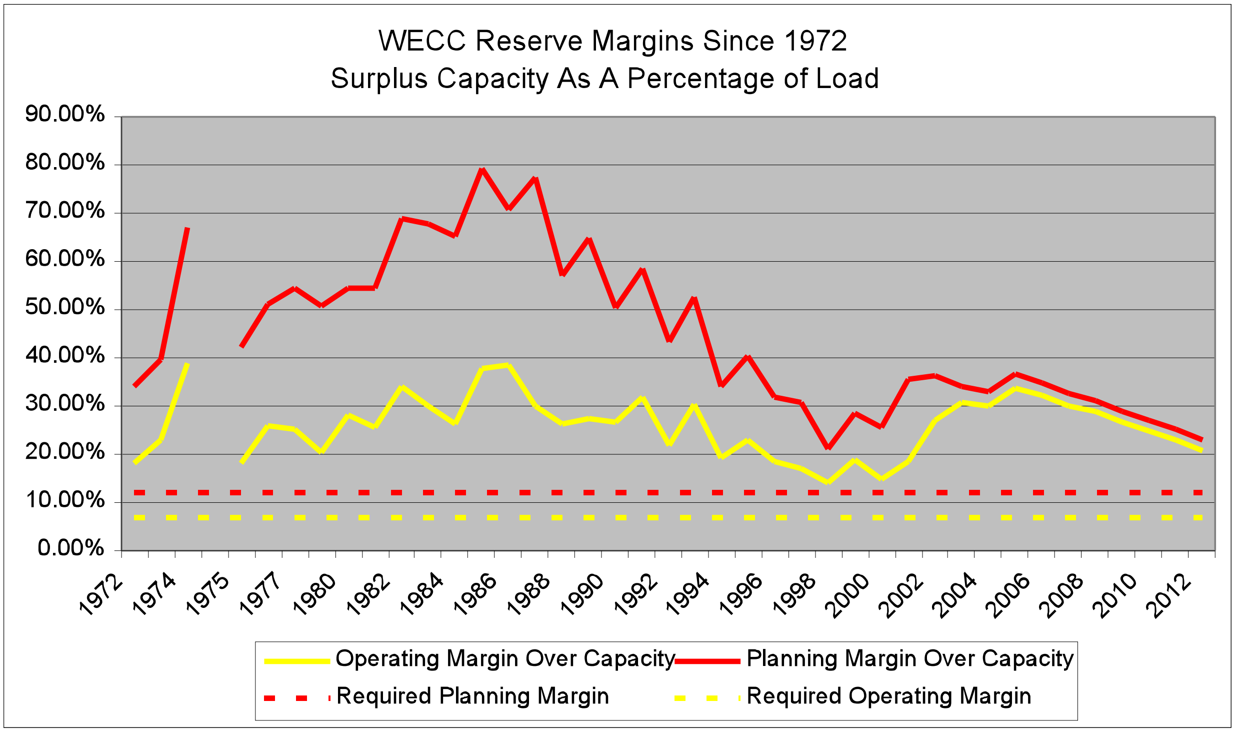
Market Basics

Until a decade ago, the *sin qua* non of utility resource planning was a fairly simple set of calculations. First, calculate the reserve margin and determine whether it met reliability standards. Second, calculate the most efficient resource based on annual expected operations, and third look up the amount of each resource required from the load duration curve. Voila, the apprentice resource planner could calculate the optimal resource portfolio. Although this turns out to be mathematically equivalent to linear programming, the simplicity and intellectual rigor of such a simple process somehow seemed lacking. Today, of course, we can get the same answers by a vastly more mathematical approach.

The first step is the estimation of resource adequacy. The Western Electricity Coordinating Council provides a very useful report on an annual basis, the 10-Year Coordinated Plan Summery.[3] This document contains a summary of the load and resource projects for the WECC for the following ten years. It also provides a snapshot, by month, of the previous year. Recent Summaries can be found on the WECC web site, WWW.WECC.BIZ.

The following chart summarizes reserve margins since 1972. The solid lines represent the actual margins – on both a planning and an operational basis calculated on the basis of annual peak loads. The dotted lines represent the required margins. The primary difference between the planning margin and the operational margin is an allowance for forced outages. As a function of load, a planning margin is approximately 12%. This allows a 5% allowance for forced and scheduled outages. Our experience in the WECC is that this allowance has been more than adequate, with the exception of the 2000/2001 period when the thermal units owned by marketers apparently turned in the worst operational record in the industry's history.

[3] It is always worth noting that the apologists for the firms investigated (and usually fined) for market manipulation in 2000 and 2001, never cited this document in their arguments that the region lacked capacity during the crisis. The excellently written essays by Drs. Hogan, Harvey, and Kalt all apparently missed the single most important resource of load/resource balance in the WECC.



Since a new Plan Summary hasn't been released for 2003, the values for 2003 through 2012 are forecasts.

Samuel Insull's approach to guaranteeing investors a return on invested capital provided a more than ample incentive for capacity construction through the 1980s. During the 1980s, the PURPA boom continued to drive reserve margins up – even though by any standard, resources far exceeded requirements. The advent of competition reduced reserve margins until 1988 – their lowest point – and they have gradually increased since then.

Projected reserve margins through 2012 show little need for new resources. In fact, for the entire planning period, margins are forecasted to exceed required reserves by a factor of two.

The question why so many resources are currently planned for this period has an easy answer. Prices – especially prices during the 2000/2001 period – are significantly higher than resource cost. If read honestly, this chart should make both sides of the "deregulation" debate very uncomfortable. Traditional regulation did a terrible job. Regional resource margins of 50% and above did not speak well for the acumen of the regulators.[4] By the same token, the forecasted margins for the next decade don't speak very highly for the acumen of resource developers.

[4]Regulatory practice actually faired well on reserve margins, but did not handle load forecasting well. Overbuilding during the 1970s was generally a product of high load forecasts rather than overstated reserve margins.

Prices today are quite high as well. Using PGE resource plan exemplars, a combined cycle unit can be built for approximately $55/MWh.[5] This is very close to Platt's estimate of forward prices:

Long-term Forward markets, Sep 10 ($/MWh)

	Oct	Nov	Q4	Q1 05	Q2 05	Q3 05	Cal 2005	Cal 2006	Cal 2007
Mid C	38.50	43.00	44.00	51.25	35.00	50.75	47.00	46.00	45.25
Palo Verde	43.25	45.25	45.50	53.75	53.00	63.75	56.25	55.25	53.75
NP15	48.75	50.75	51.75	59.25	54.50	67.50	60.25	59.75	58.00
SP15	49.50	50.50	51.75	60.00	58.00	69.50	62.00	61.50	60.75

† All forward prices are for on-peak delivery

Of course, one question is why Platt's would believe that 2007 on-peak prices would be higher than the marginal operating cost of a combined cycle unit in a year where the reserve margin is 32%. This is really the crux of the matter, and I'll propose an answer after we finish planning the WECC.

Resource Planning 101

The second step is to find the best resources to build under different dispatch scenarios. In the 1970s, this exercise could be accomplished with a slide rule and a ruler. Today, we work more elegantly, but we get substantially the same answers.

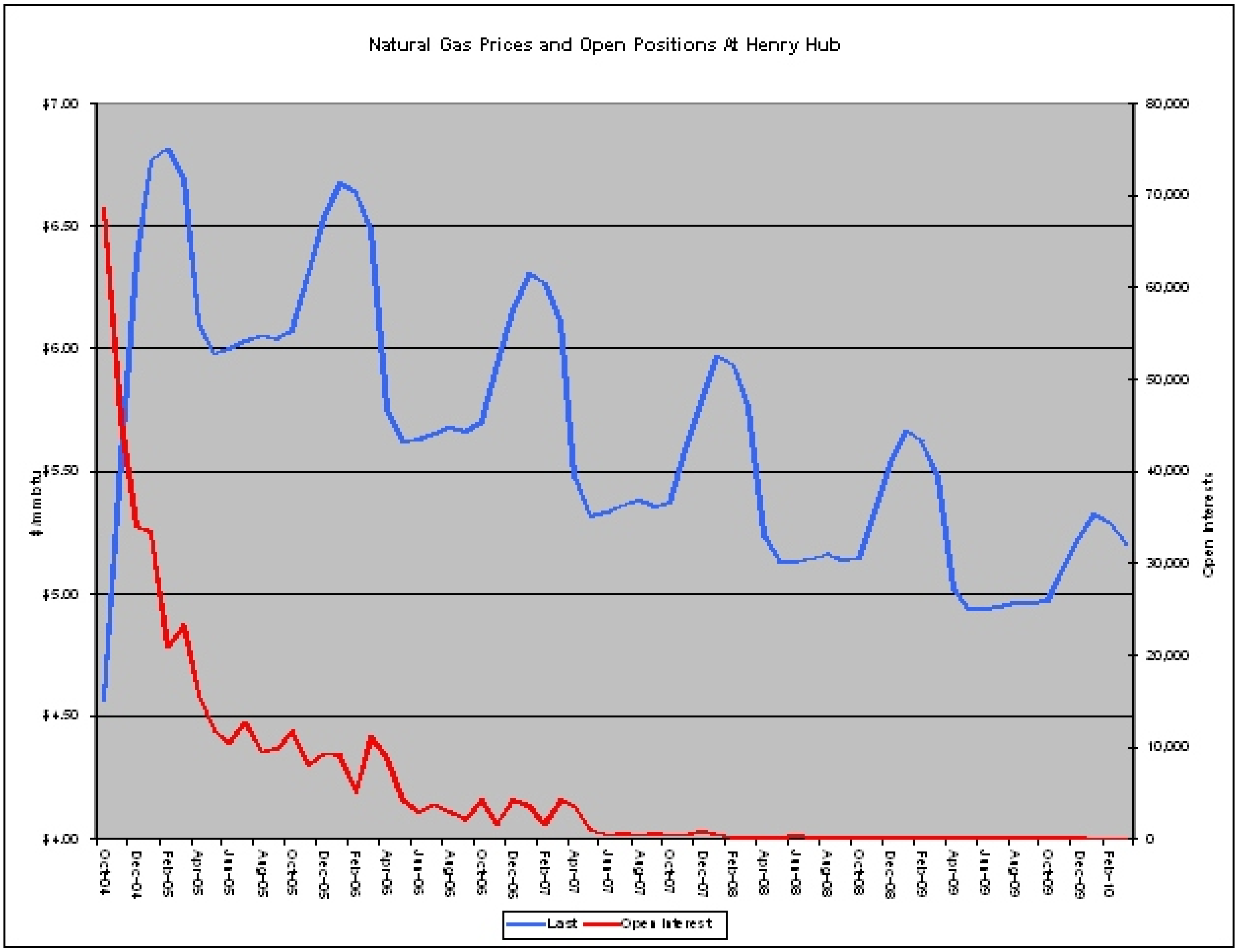
PGE has recently finished a planning cycle and their resource costs are reasonably fresh. I would quibble mildly with their assignment of $500/kW for a peaker, but the overall values are logical. Political correctness held in abeyance, only three major resource choices are currently viable: single cycle gas turbines, combined cycle gas turbines, and coal units. Not surprisingly, at natural gas over $4.00/mmbtu, Coal units tend to dominate in every scenario. This has also been true since the dawn of time, so it should not surprise us unduly.

The most critical variable is the long term price of natural gas. On the theory that there is no authority better than that of the free market, a logical place to start is the NYMEX Henry Hub forward market.[6] Henry Hub is the jewel in the crown of free markets – easy entry/easy exits, many buyers and sellers, and no centralized governmental administration.

The next chart shows us the best possible intelligence on future gas prices. This information is so good, that if you have better information, the market will pay you billions – all you need to do is to take a position and collect your profits.

[5] Assuming dispatch for on-peak hours. Natural gas price was assumed to be $5.00/mmbtu. September 10, 2004 Platt's Energy Trader.

[6] WWW.NYMEX.COM.

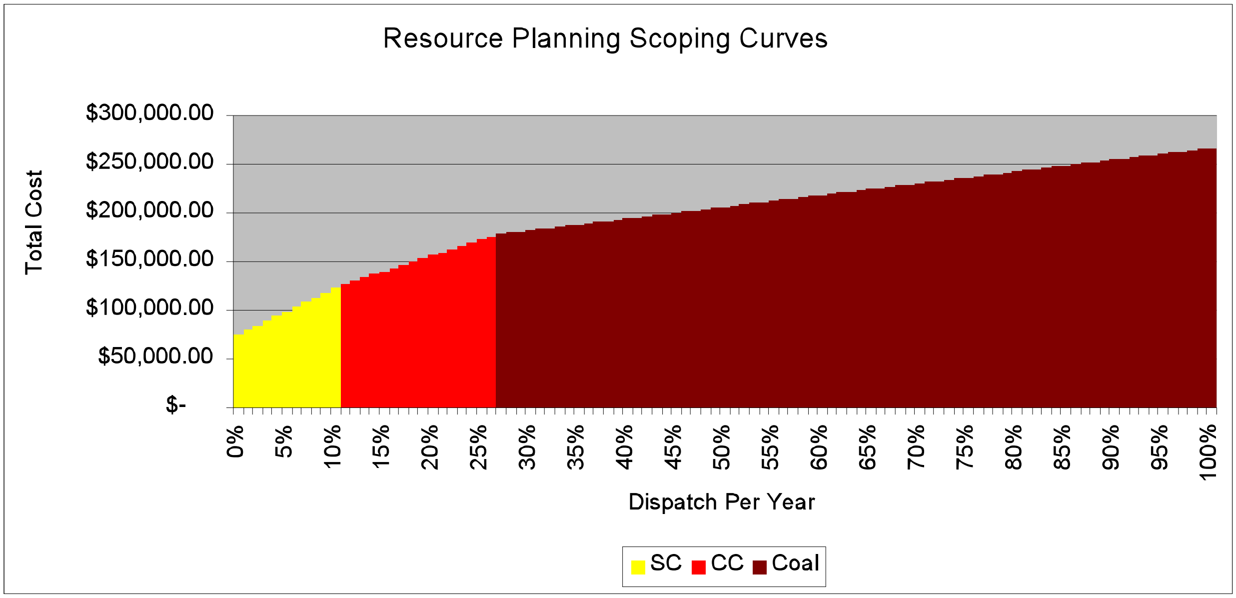


The blue line on the chart tells us that prices are slowly converging to $5.00 in 2009 and 2010. This is reassuring until you carefully review the red line – the amount of contracts actually available in later years.

The meaning of this chart is that even the jewel of forward energy markets is painfully thin more than a few years out. Stripped of the trading cant, this simply means that the smartest money in the market isn't talking. In fact, there is just the smallest whisper of guidance on the direction of future natural gas prices.[7] As a strong believer in price theory, I am glad to set our forecast of long term prices at the whisper we see in 2009 and 2010. After all, the holder of the 25 open contracts in February 2010 wouldn't mislead us.

[7]As electric energy experts, we already know the answer. The single largest market for natural gas is electricity and we know that natural gas is only competitive with coal at $4/mmbtu or below. A question for the reader is why you have not offered to fill these future contracts at these high prices. After all, you can always purchase natural gas at the end of the decade at $4.00/mmbtu or less, right?

Now that we have the natural gas price, building the scoping curves is child's play. We first need to determine which resources are most efficient for infrequent (peak) loads, for intermediate loads, and for base loads. Our traditional approach is to simply ask the data the question and see:

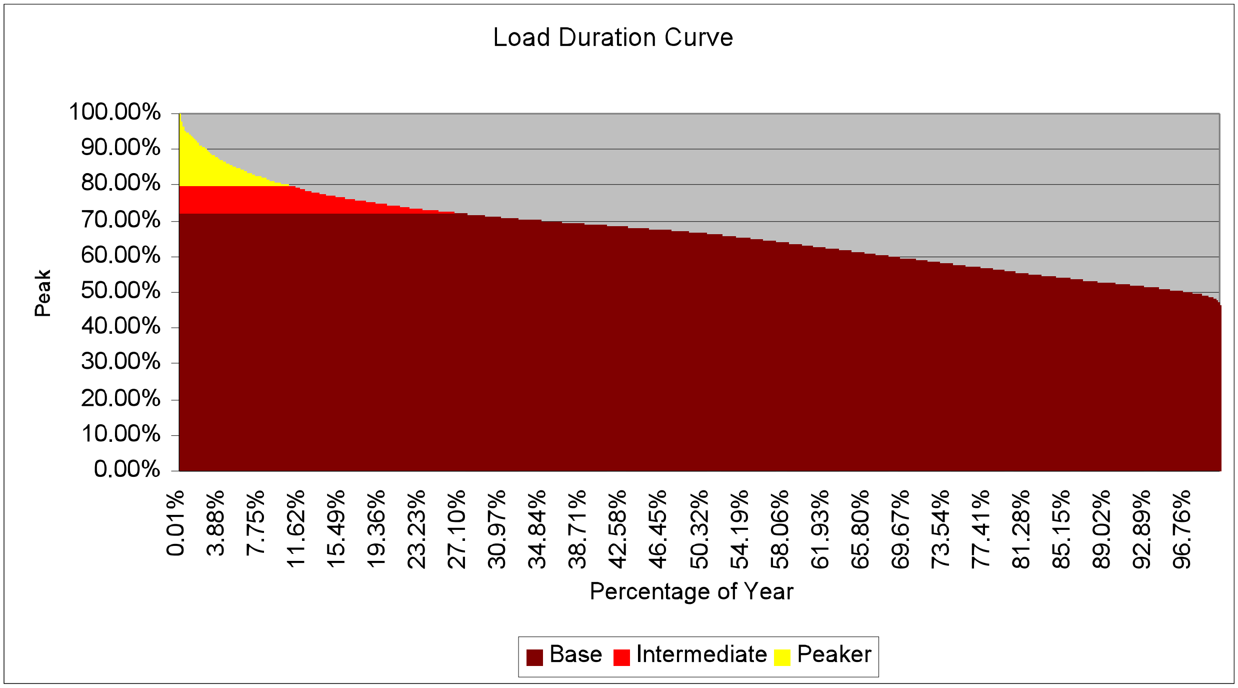


Not surprisingly, simple cycle turbines turn out to be inexpensive choices for loads of short durations, combined cycle units are efficient for loads of intermediate durations, and coal units are best for base loads. While not politically correct, at $5.00/mmbtu, coal dominates the resource portfolio for loads of 20% of the year or longer.

This not news. As we have known from our childhood, the price of natural gas is the critical variable – in part because as one McCullough Research client put it years ago, "the great plains are simply six feet of topsoil on top of coal from Alberta to Ohio." North America is full of places where you can have all the coal you want if you promise to put the corn fields back when you are done.

The next step is to take out choice of efficient resources and assign them to the load duration curve. A leftover artifact of efficient utility planning is the FERC 714 Report.[8] The WECC provides data by control area on an annual basis. The load duration curve analysis is equally straightforward:

[8]http://www.ferc.gov/docs-filing/eforms-elec.asp.



In an optimal planning environment, we should be 20% single cycle turbines, 7% combined cycle turbines, and 72% coal units.[9]

How Are We Doing?

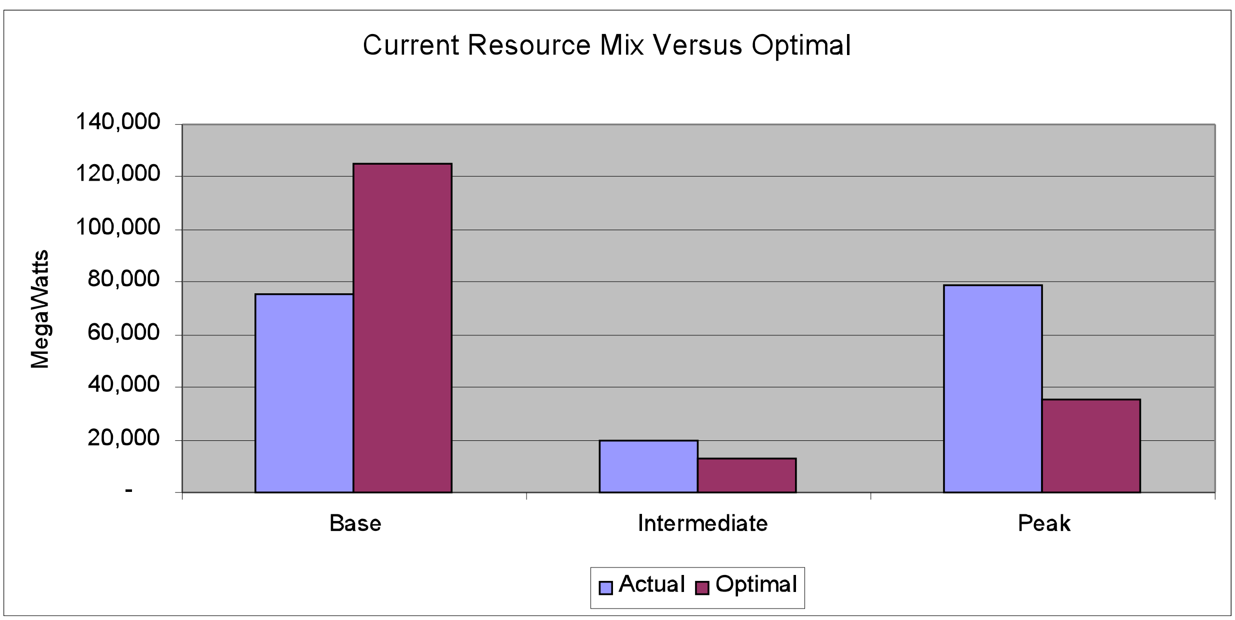
The 2003 10-Year Coordinated Plan can give us a good idea of how good a job we are doing to implement the optimal choices derived above. Table 11 gives us a fine summary of existing resources:

[9]This conclusion tends to cause a bit of outrage, since most local activists are more opposed to transmission lines than natural gas pipelines – even if both meet environmental guidelines.

Table 11 - Existing Generating Capability as of January 1, 2003 (Summer Capability - MW)

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	46883	902	4463	7193	59441	34.3
Hydro - Pumped Storage	0	410	245	3840	4495	2.6
Steam - Coal	17153	6156	9856	3604	36769	21.2
Steam - Oil	0	0	128	276	404	0.2
Steam - Gas	2613	218	2345	18016	23192	13.4
Nuclear	1170	0	3733	4450	9353	5.4
Combustion Turbine	3768	1586	2688	6787	14829	8.5
Combined Cycle	5429	1509	5868	6600	19406	11.2
Geothermal	143	0	450	2184	2777	1.6
Internal Combustion	216	238	4	40	498	0.3
Other	1111	26	126	1013	2276	1.3
Total	78486	11045	29906	54003	173440	100.0
Percent of WECC Total	45.3	6.4	17.2	31.1	100.0	

The portfolio of existing resources does not match our optimal portfolio terribly well:



We currently have too many peak resources and too few baseload resources. Too a degree, this is due to the fact that our large hydroelectric resources are closer to peakers than baseload in practice.[10] Obviously, it also reflects the fact that we have just come off a fifteen year period when natural gas prices were very low.

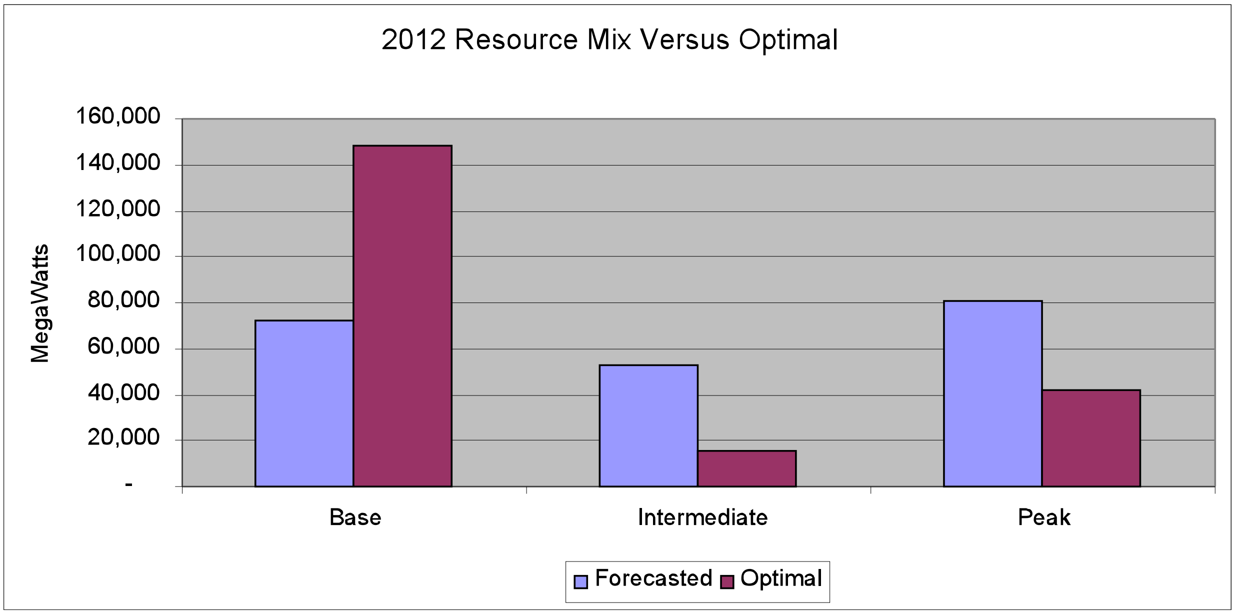
A more interesting picture is how well resources planned through 2012 match our optimal portfolio. A good departure point for this is Table 13 of the 10-Year Coordinated Plan Summary:

Table 13 - WECC Summary of Generation Additions (Summer Capability - MW)

Generation Type	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Yr. Period	% of Total
Hydro - Conventional	382	95	10	4	0	0	0	500	0	0	991	3.1
Hydro - Pumped Storage	10	10	20	10	10	0	0	0	0	0	60	0.2
Steam - Coal	75	100	1290	-1580	800	0	0	0	0	0	685	2.1
Steam - Oil	0	0	0	-48	0	0	-276	0	0	0	-324	-1.0
Steam - Gas	-1193	-1788	-163	-358	0	-444	0	0	0	0	-3946	-12.2
Nuclear	115	0	0	0	0	0	0	0	0	0	115	0.4
Combustion Turbine	909	-255	160	0	0	75	0	75	0	0	964	3.0
Combined Cycle	12585	6359	7899	3539	750	887	357	357	357	0	33090	102.3
Geothermal	0	105	40	20	120	0	0	0	0	0	285	0.9
Internal Combustion	8	0	0	0	0	0	0	0	0	0	8	0.0
Other	54	58	1	275	1	1	2	1	2	0	395	1.2
Total	12945	4684	9257	1862	1681	519	83	933	359	0	32323	100.0

Unfortunately, we are doing worse in the future than we are today. Our market solutions are actually diverging from optimal.

[10]Again, Drs. Hogan, Harvey, and Kalt have normally assumed that all dams are run flat – and run of river. This insight apparently was arrived at without extensive research.



As can be seen from Table 13, almost all resource development planned through 2012 is natural gas fired combined cycle. Clearly, we have done something wrong.

Where Did We Go Astray?

As you have guessed by now, we didn't go astray. The problem had to do with the "whisper" of natural gas prices in the NYMEX Henry Hub market and the correspondingly thin forward markets for electricity.

While Enron used to say that it profited on volatility – it turns out that they omitted mentioning the widespread commercial and financial fraud – they were not describing a good thing. We are having exactly the same problem today that Tom Edison was having at the turn of the century. The lifetime of central station investments is an uncomfortable fit for forward markets. The "smartest guys in the room" don't know very much about markets over the thirty year life of our proposed "optimal" coal unit.

When Enron failed almost three years ago, a curious thing occurred. Forward prices in the market appeared to fall. Those of us who were in the market at the time were surprised. We had assumed that Enron was packaging supplies through their superior risk management techniques. We thought that they were net suppliers. The exit of the largest supplier in the market should have driven prices up – not down.

Three years later we still don't have a cogent answer to this anomaly. Only two groups have taken the issue on – FERC staff in the initial staff report on the California Crisis argued that forward prices always fall in the winter. I hope they soon afterwards quit FERC and made their fortune buying forward contracts in December and reselling them in March.[11] Platt's was apparently somewhat angered by my use of their price series in my presentation to the Senate Energy and Natural Resources committee. Their explanation was even more amusing – they explained that the fall in 2003 and 2004 forward prices was the early bird hydro forecast that occurred a month after Enron's bankruptcy and the price decline.[12] I hope they did not quit their jobs to speculate on the price impacts of the as yet unissued early bird forecast on market prices for energy that would have not been generated until after the 2002/2003 and 2003/2004 were issued.

Luckily, we do have the source data to review the facts today. The surprising answer is that there were very, very few long term contracts signed during the California Crisis.[13] There were no contracts signed for calendar year 2003 and calendar year 2004 in the weeks around the Enron bankruptcy declaration.

In spite of the absence of market transactions, trading floors made bids, Enron Online listed products, and Platt's – as well as other publications – listed the prices for future years.

Where were the prices for this very thin – some would say nonexistent – market coming from? A more witty person than myself might well answer that the prices had been formed by a consensus of the uninvolved. This is probably pretty close to the facts.

The correlation between forward and spot prices at COB (and elsewhere) is quite high. This is surprising to the economist, since we would expect that the one year strip prices have been set by careful analysis of longer term fundamentals. To find them correlated is like finding a farmer deciding his annual crop planting on the basis of one morning's weather. However, the farmer knows quite a bit more about the problem than we do. His environment is relatively transparent. He certainly is not restricted from critical market data for six months to come. In California, on

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[11] If calendar year forward contracts always fell in December and recovered in the spring, any reasonably observant broker could make billions by simply buying the contracts every December and reselling every March. A con man used to sell similar patterns for investing in pork bellies in the Chicago Board of Trade – allowing an unsuspecting victim to follow the "historical pattern" and lose his shirt. Obviously, pork bellies reflect fundamentals and calendars.

[12] At the end of the year, the Northwest River Forecast Center issues an early bird forecast based on snow depth in the Rockies. This is valuable planning information for the following year. Enron's bankruptcy preceded the forecast by a month (it even preceded much of the snowfall). The forward prices for 2003 and 2004 would reflect the early bird forecast issued a year following Enron's bankruptcy and the year following that. If Platt's had bought and sold 2004 based on the 2001/2002 early bird forecast, they would have lost their shirt; 2004 was only 78% of the 1971-2000 average. See http://www.nwrfc.noaa.gov/water_supply/ws_runoff_display.cgi?TDAO3.

[13] In response to my testimony before the Senate Energy Committee, FERC launched an investigation into possible market manipulation. One step in the investigation was a FERC data request to the WECC market participants for long term transactions. The database can be found at www.ferc.gov/industries/electric/indus-act/wem/pa02-2/info-release.asp.

the other hand, market participants had little information except that which they unearthed through clandestine means or procured from out of state sources.

When the spot off-peak prices in early December 2000 spiked, what information could any market participant draw from the event? Was there a real shortage on that day? Was the price spike simply a mistake? How prudent would it be to ignore it in making longer term judgments? While we know today that the spike was deeply suspicious, no prudent market participant could have known that fact at the time.[14]

As market prices become less transparent, a logical market participant has to use what little information is available. During the California Crisis, market manipulators fought a successful battle to keep basic data out of the hands of market participants, regulators, and legislators. To this day, the ISO routinely resists data requests concerning market data for the period.

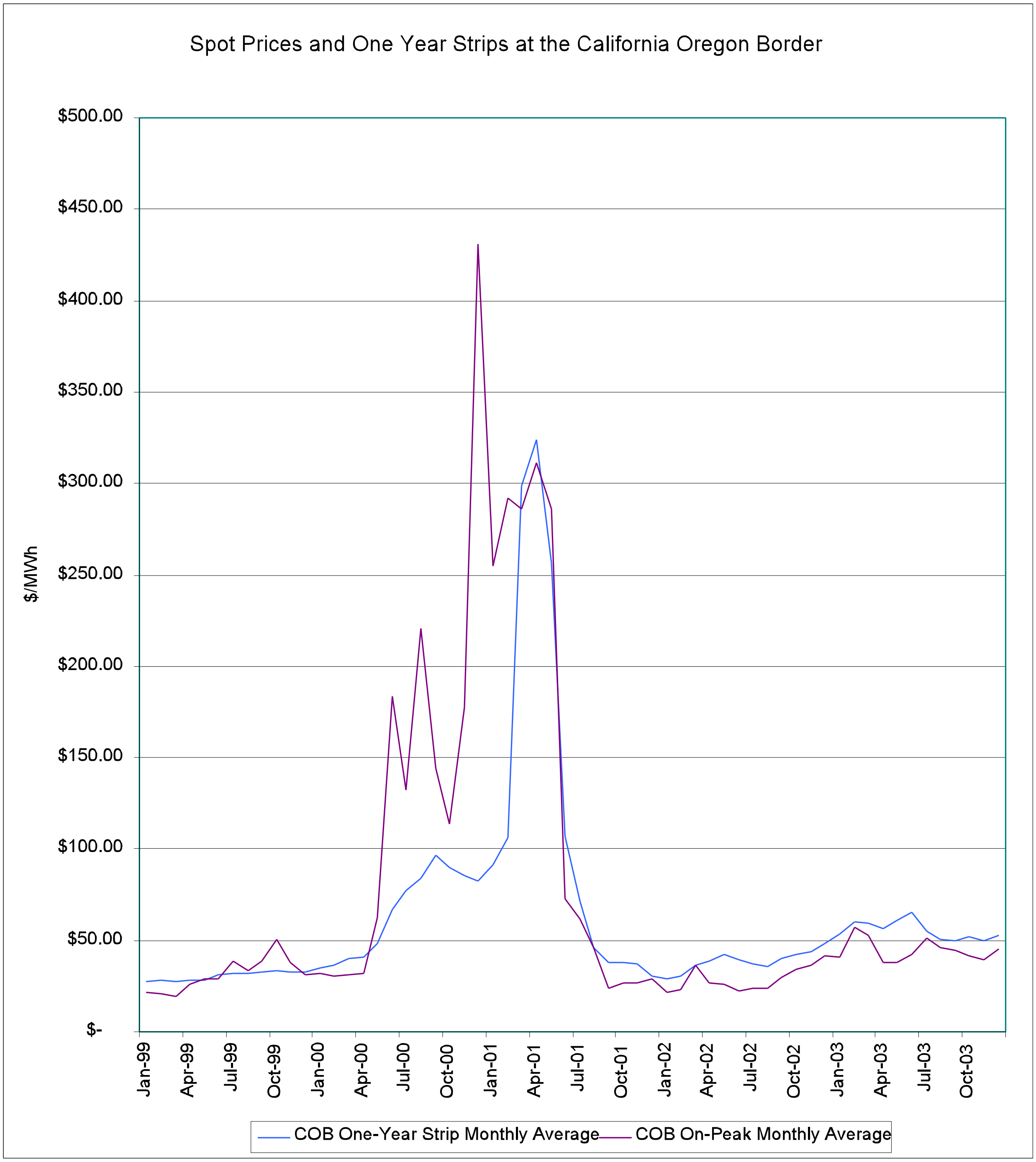
The structure of market prices makes the relationship between spot and forward prices very clear. The next chart shows spot and one year strips from 1999 through 2004:

[14]The two most expensive Dow Index prices at COB took place during the peak hours of December 12, 2000, when the price reached $818.75, and during the off-peak hours of December 11, 2000, when the price reached $1,187.50. There has been considerable suspicion in the industry concerning these prices. In general, hydroelectric utilities are able to choose when to generate. Since loads are much lower at night than during the day, prices for off-peak power are almost always lower than those at peak. On December 11th, this pattern was mysteriously reversed. In reality, the reversal was due to a day when only 400 megawatt hours determined the entire off-peak Dow Jones index.

Only Avista, LADWP, PGE, Puget, Mirant, NCPA, and AEP reported selling firm off-peak power on December 11, 2000 to FERC. The weighted average of the transactions reported to FERC was $764.11 per megawatt hour – a significant step down from the $1,187.50 reported to Dow Jones. Only one reported transaction was above the Dow Jones price, so by the rules of arithmetic, it must have been included in the Dow Jones filing – a sale from Mirant to Duke at $1,500 per megawatt hour for 200 megawatt hours. This implies that the remaining sale included in the Dow Jones COB off-peak index was at $875.00 and there are two eligible sales from AEP to Snohomish at that price.

How accurate was the Dow Jones index on December 11, 2000? The index erred by 55%, reporting $1,187.50 rather than the $764.11 reported to FERC. Only one reported sale, Mirant to Duke, took place above the Dow Jones price. PacifiCorp bought a small block of power off-peak for $350.00 per megawatt hour. Enron and PGE also purchased blocks from NCPA and then resold the power at a sizable profit to the California ISO, a likely ricochet.

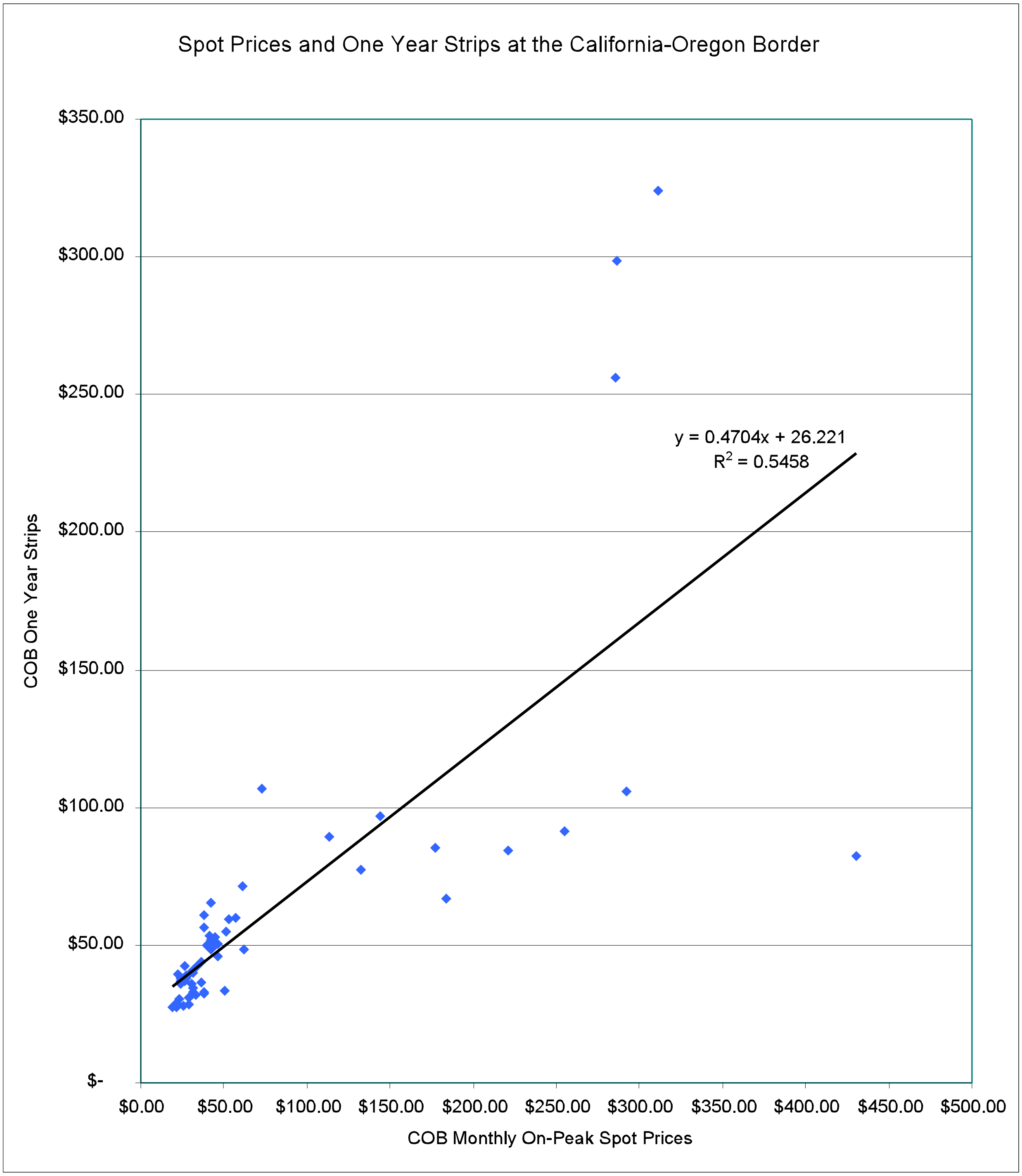
Duke, on the other hand, bought just one block at twice the market price paid by the other market participants. Duke did not file a report with FERC that they actually sold any off-peak short term power on December 11, 2000, leaving the obvious question of where the 200 megawatt hours actually went. Since 200 megawatt hours is a small quantity by regional standards, it is possible that Duke used it to replace generation from a power plant. We know the cost of production at Duke's power plants, and Duke's cost of production was no where near this level on December 11, 2000. We also know that Duke had extra capacity at its California plants on December 11th.



While it is easy to understand this chart intuitively, it resists a simple statistical analysis.[15] A

[15]See Chapter 5 of the Final Staff Report on the California Crisis.

straightforward regression gives an unbiased value for the relationship as:



Simply taken at face value, every dollar increase in spot prices is interpreted as a 47 cent increase in long term prices.

How does the consensus of the involved make long term forecasts? There is ample evidence that they lick their collective fingers and check which way the wind is blowing.

What Impact Does This Have On Plant Section?

As a rule, forward markets need to reflect underlying needs. When this rule fails, we entertain non-market solutions.

At the moment, it is relatively easy to finance a GE Frame 7 turbine. They are roughly standardized, can be installed quickly, and are a bargain in terms of capital cost. The "optimal" coal units don't have any of these virtues.

The lack of transparency – helped by healthy doubts concerning the costs of natural gas and fuel – make long term prices unduly volatile.

At the turn of the century Sam Insull solved this problem by prevailing on state legislators to guarantee the cost of efficient central station units through cost plus regulation. If he hadn't, we would still be going out to the garage to fire up our Honda generators before we could cook dinner.

The cost of volatility is a high shadow price of financing. The outcome of uncertainty is a preference for short term projects that can be readily sited and financed.

Looking Forward

At face value, this essay is simply another argument in favor of open markets for electricity. Unfortunately, that may not be sufficient to make an optimal portfolio of resource choices financeable.

Not having the forecasting ability of the FERC staffer who discovered that forward markets were always cheap in December, the resolution is not easy to foresee.

The outcomes that seem likely are:

1. Institutions with the ability to hold onto customers – public power in most parts – will be able to finance and operate more efficient resources. This may well help fuel the backlash against the current policy preference for tightly centralized markets.

2. We can shift to short term resources with the inevitable cost of not using less expensive fuels. Since natural gas and oil prices are closely correlated, this would seem a poor

policy outcome.

3. Proponents of centralization could force all market participants into tightly administered long term markets. This seems frightening – a form of state sponsored socialism – in the name of free markets.

At the moment outcomes one and two seem likely. The third outcome seems outlandish, but the seductive sound of P=MC has achieved miracles in the past few years – even in many cases at the cost of efficiency and transparency.