Looking for the "Voom"

A Rebuttal to Dr. Hogan's "Acting in Time: Regulating Wholesale Electricity Markets"

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In 1958, the very gifted Dr. Theodore Seuss Geisel published The Cat in the Hat Comes Back.[1][2] While this beloved children's book is not normally cited as a primer for public policy, its principal character, the Cat in the Hat, serves as a good model for the continued efforts to implement administered electricity markets in the United States. The Cat, a charming, irresponsible individual, proposes plausible, but increasingly disruptive, suggestions. As the story unfolds, each suggestion requires a new Cat in the Hat to solve the resulting problems. Finally, the smallest cat of all provides a magical substance called "Voom" to clear up the mayhem caused by the Cat and his followers.[3]

Many practitioners in the electricity industry have begun to yearn for a policy "Voom" that would put the Cat and all of his misadventures back in the hat. Dr. Hogan's latest proposal is very much in the tradition of Dr. Seuss's famous protagonist. "Acting in Time: Regulating Wholesale Electricity Markets" contains two different suggestions. The first exhorts the Federal Energy Regulatory Commission (FERC) to continue its proactive policy in favor of replacing existing markets with centralized administered markets. This is a basic philosophic position that represents Dr. Hogan's belief that markets are best implemented and administered by government. Despite the success of the Western Systems Power Pool, formally implemented in 1991, and now in place for over twenty years, Dr. Hogan still prefers tightly centralized structures. He is also a believer in the primacy of regulation over markets – the need to design and administer markets for their own good. His second suggestion concerns the absence of new resource construction.

The results of Dr. Hogan's suggestions, like those of the Cat, have been mixed. In the mid-1990s, he won the debate in California to reject open markets in favor of the tightly organized and deeply administered system that has had such a troubled history. Like the Cat, the unforeseen results were not his fault – Dr. Hogan has frequently pointed out that it was the implementation of his ideas that was faulty. Many of us are in substantial agreement. Whether FERC should continue its proactive stance to replace open markets with administered markets is still the subject of debate. Some believe that having governments design and administer markets is an oxymoron. Certainly, the increasing differential in electric rates between those serving customers in open market states and those serving customers in administered market states indicates that much remains to be understood about the merits of turning markets over to centralized, quasi-governmental agencies.

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[1] My thanks to the APPA for funding this research paper. All opinions and analysis are strictly my own.

[2] The Cat In The Hat Comes Back, Theodore Seuss Geisel, 1958.

[3] For technical details of Voom, see pages 57 through 59.

Dr. Hogan's second suggestion is designed to solve a problem that has afflicted states being served by administered markets – the absence of new resource construction. He notes that the "missing money" problem is a major hindrance (the term was coined by Roy Shanker almost five years ago to describe the absence of incentives for new generation). The crux of Dr. Hogan's argument is that

> In particular, prices in organized markets tend to be too low during conditions of generation capacity scarcity, exactly the time when the unexploited demand side resource would be most valuable. But without the signal and the reward through prices, there is insufficient market incentive for demand side action or for adequate infrastructure investment. There are many reasons for this inadequate scarcity pricing that relate to both mistakes in market design and practices of system operators.[4]

It appears, however, that Dr. Hogan does not recognize that the missing money problem is endemic to his preference for an energy-only administered market.

Dr. Joskow has also written on this issue in "Competitive Electricity Markets and Investment in New Generating Capacity."[5] He develops a simple electric market using traditional planning tools, even going so far as to assume values for loads and plant costs. Since technical points are always more accessible with simple examples, I have taken the liberty of "borrowing" his example.[6]

Calculating the "Missing Money" in Dr. Hogan's Paper

To plan the optimal electric system, the following straightforward technique should be included in the tool kit of every aspiring resource planner:

1. Establish the fixed and variable costs for all available resource options
2. Calculate the total cost for each resource over the 8,760 hours in the year
3. Choose the least cost resource for each hour of the year (the evocative term economists use for this step is finding the "convex hull" of possible resource options)
4. Find the hour corresponding to each vertex of the convex hull
5. Determine the required capacity by reading the load off the load duration curve for that hour.

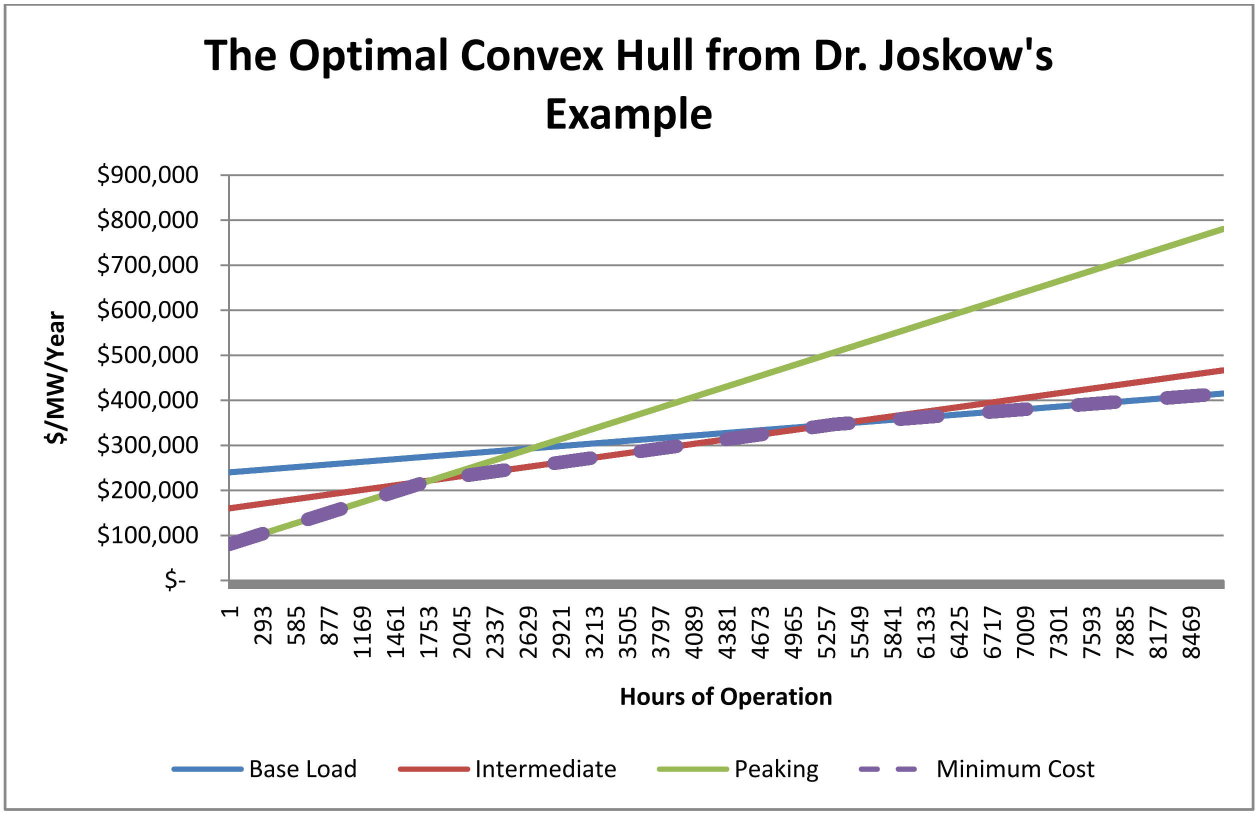
While Dr. Joskow's example only extends to three resource options – Base Load, Intermediate, and Peaking, the five-step technique works for any set of resource options as long as the costs are linear functions of the expected dispatch. Dr. Joskow's Table 8 assumes the following values:

Technology	Capital Costs ($/MW/Year)	Operating Costs ($MWh)
Base Load	$240,000	$20
Intermediate	$160,000	$35

[4] Acting in Time: Regulating Wholesale Electricity Markets, William W. Hogan, May 8, 2007, page 5.
[5] Competitive Electricity Markets and Investment in New Generating Capacity, Paul Joskow, June 12, 2006.
[6] Ibid., Table 8, page 69.

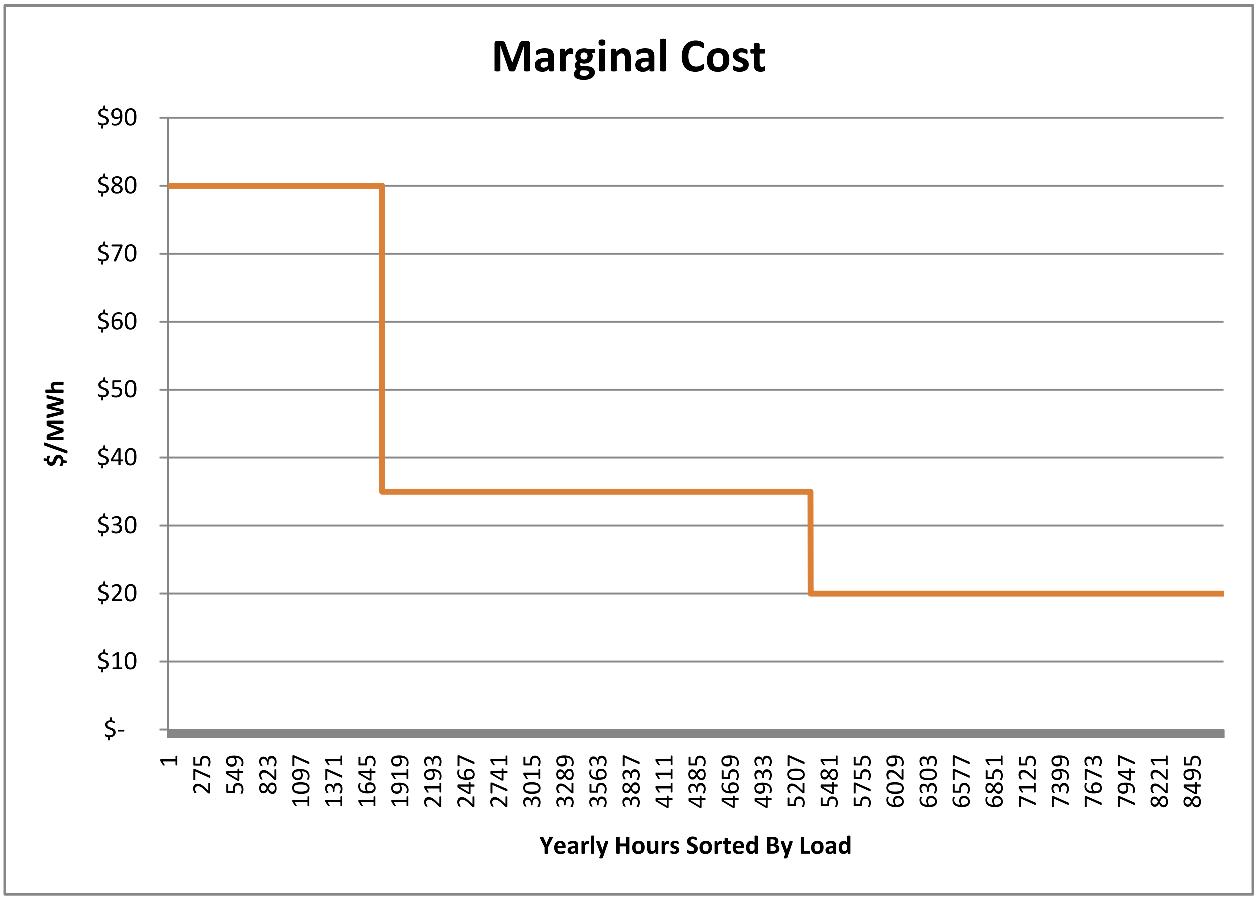
Peaking	$80,000	$80

The optimal mix of resources can be readily calculated by observing which plant type is best for each level of expected operation:



The least expensive result for each hour is represented by the dashed line which shows the best choice of resource for each level of expected operations. Not surprisingly, in this example, peakers are optimal for operations over a small number of hours (1 through 1,777), intermediate resources dominate from 1,778 through 5,343 hours a year, and base load units are best for longer durations (5,334 hours through 8,760 hours a year).

Prices in this very simple example are easy to derive. During high load periods, the marginal resource is a peaker. Hence, market prices are equal to the running costs of all peakers – $80/MWh. During shoulder hours, the marginal unit is the intermediate resource – $35/MWh. Finally, during the off-peak hours, only the base load units are dispatched and the marginal cost falls to $20/MWh.



This makes it very easy to calculate the expected revenues for a new resource. The owner of a new peaker would quickly note that if prices never increased above marginal cost, it would never be able to make any contribution against its fixed costs. Thus, the owner would lose its fixed costs – $80,000/MW/Year – if it invested in this market.

Surprisingly, this is also true for the owner of an intermediate resource. Although more complex, the calculation gives the identical result. Thus, the owner's calculation would credit the producer's surplus (the area above the marginal cost it would receive during peak periods) against capital costs. In this case, the owner would receive $45/MWh ($80/MWh-$35/MWh) for the 1,777 peak hours in the year, or $80,000, the capital costs would be $160,000, and the net loss would be $80,000.

The owner of a base load plant fares exactly the same. The producer's surplus is $60/MWh for the first 1,777 hours and $15/MWh ($35/MWh-$20/MWh) for the next 5,333 hours. Overall, the producer's surplus would be $160,000, the capital costs would be $240,000, and the net loss would be $80,000/MWh.

It should not be lost on the reader that this is a “Cat in the Hat” moment. As it turns out, the loss for any new resource under any set of assumed costs and loads is always the capital cost of the resource with the least fixed costs.[7]

Dr. Hogan’s solution to the missing money problem would require the regulator to add enough revenues into the market to make new entry attractive. This is not an implausible suggestion, although I observe that FERC’s competitive agenda has been neatly hijacked back to the full revenue requirements model that Dr. Hogan’s solution expected to replace. To fix the problem, any determined market administrator can intervene in one of four ways:

1. The market administrator could abandon the attempt to force the market into the “energy only” model. This would entail returning to an open market solution like the WSPP. In this case, market participants could make transactions directly with each other – pricing energy and capacity as they saw fit.

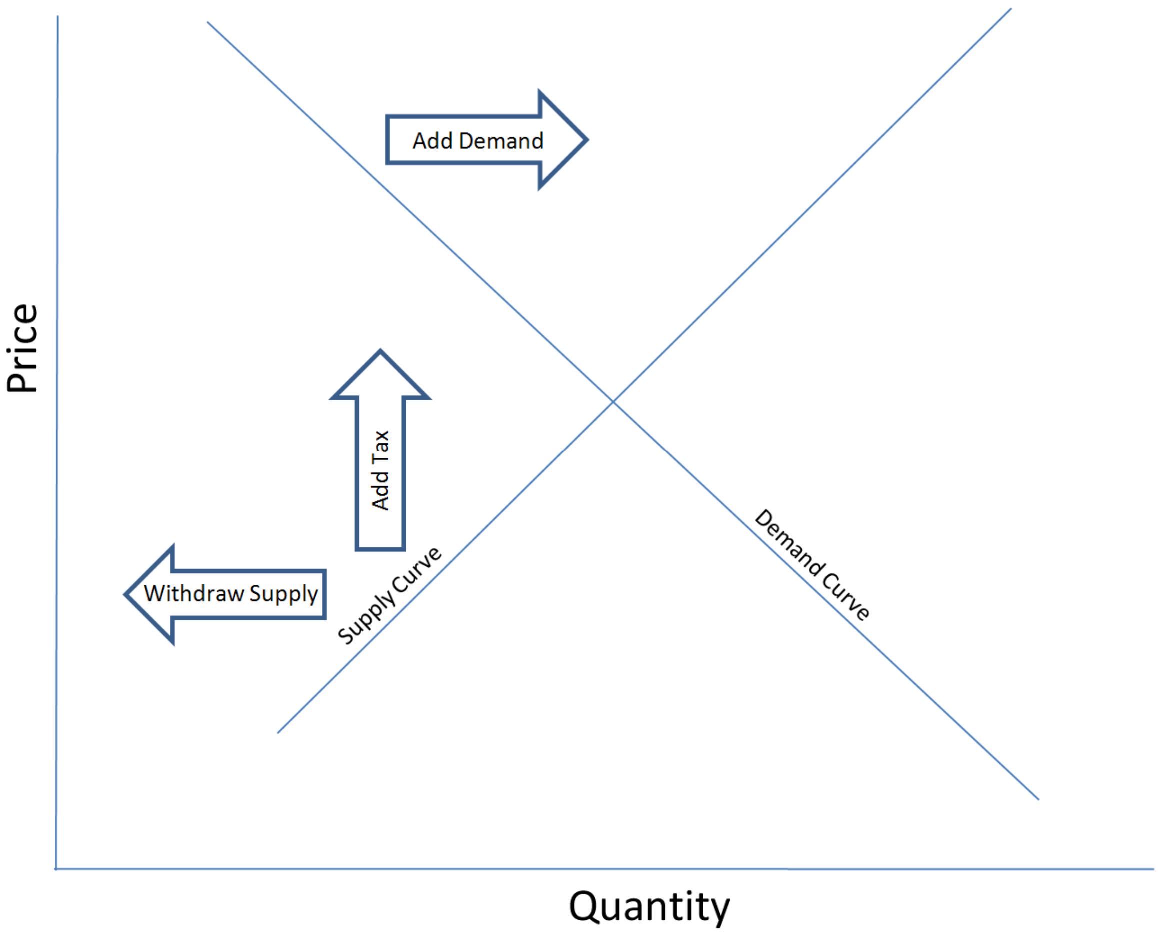
2. The market administrator could simply add to prices by placing a tax on each megawatt-hour sufficient to reimburse resource developers for their capital costs. While this returns the regulator to calculating used and useful resource costs, it is likely to be less disruptive than some of the other options.

3. The market administrator could unilaterally move the supply curve back towards the origin by not counting the bids of some of the base load resources. Again, this would raise the price, but it would add some complexity.

4. Finally, the least attractive solution, the market administrator could move the demand curve right – away from the origin – in order to raise prices. This solution is likely to move the market away from optimality, increase volatility, and encourage market manipulation.

The following figure illustrates options 2, 3, and 4.

[7] The appendix illustrates the proof with a graphical example.

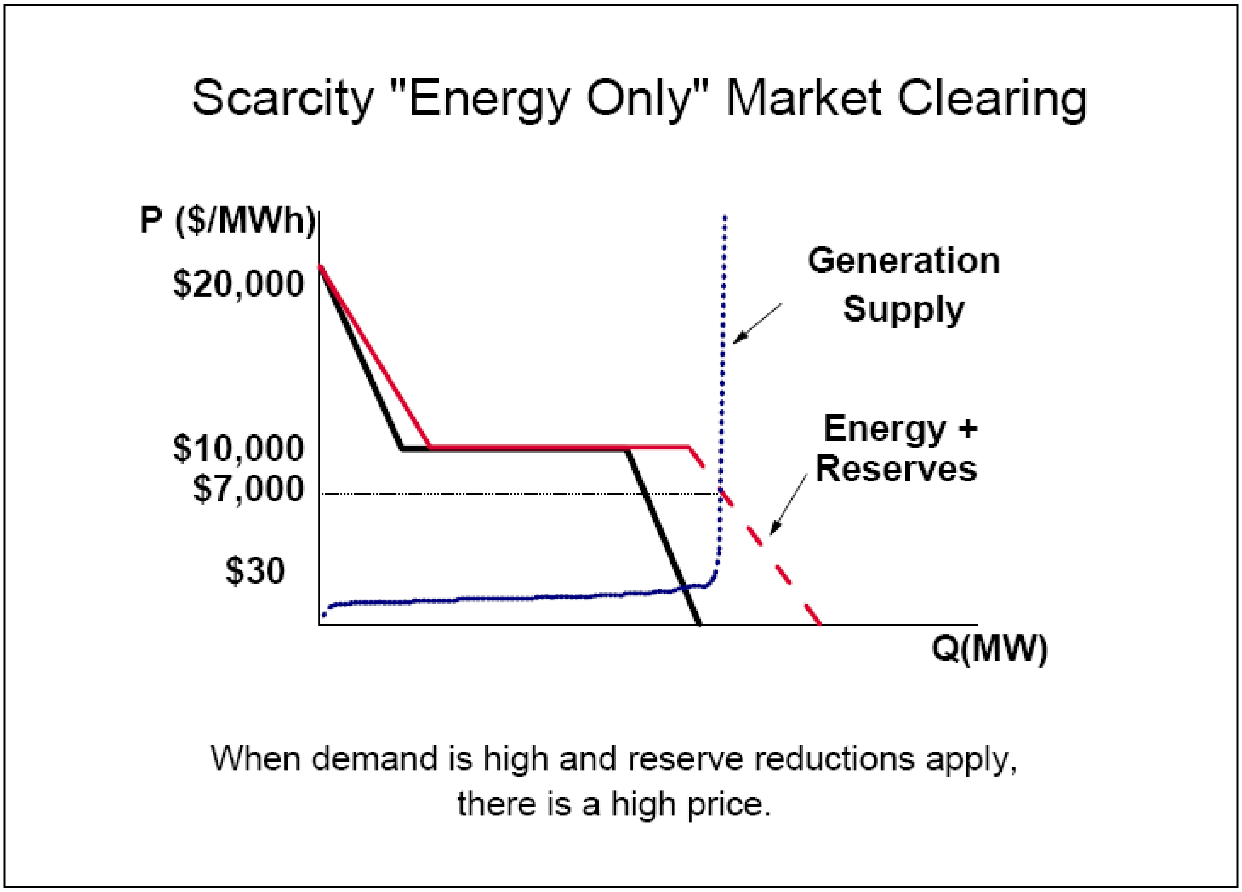


Dr. Hogan has chosen the fourth solution – the addition of demand. He says:

> This example of operating reserve demand curve based on representative data illustrates several important points regarding the shape, magnitude and costs. The shape has a simple explanation. As discussed above, there are two underlying demand curves. One is the vertical demand curve from the security minimum defined by the contingency constraint. Second is the more conventional demand curve defined by probabilistic analysis and the value of expected unserved energy. The usual rules apply to yield horizontal addition. Another way of thinking about this is that at the minimum security level of 500 MW, the probability that net demand will exceed expected net demand in the next half hour is less than one. Hence, the curved portion of the demand curve connects at a price below the VOLL.[8]

[8] Acting in Time: Regulating Wholesale Electricity Markets, William W. Hogan, May 8, 2007, page 11.

Although “Acting in Time: Regulating Wholesale Electricity Markets” does not describe what Dr. Hogan’s revised demand curve will look like with the operating reserves addition, the eleventh slide from his March 3, 2006 presentation offers some additional details[9]:



To fit Dr. Hogan’s concept into our numerical example, we must estimate the size of his assumed reserve and how often the demand curve would intersect operating reserves.

Fortunately, sample values fall directly out of the example. If Dr. Hogan requires $80,000 to “fix” the revenue shortfall, he will only need to add a small amount to the marginal cost curve. If the producer’s surplus needs to be $80,000, he can achieve the result with only $80,000/($10,000-$80), or just over 8 hours.

This result should cause some discomfort for three reasons:

1. In our simple example, tinkering with the demand curve has moved us off the optimal resource plan. The difference is not large, but it will now mean that the market will build peakers to meet 1,785 hours (1,777 plus 8) where the marginal cost of operation is larger than or equal to spot prices.

[9] Reliability and Scarcity Pricing: Operating Reserve Demand Curves, William Hogan, March 3, 2006, slide 11.

2. Dr. Hogan's solution has a perceptible impact on the volatility of prices in the market. When the market is allowed to operate without intervention, volatility is 58%. In Dr. Hogan's improved version, volatility has risen to 637%.[10]
3. Only a very ethical market participant would reject taking capacity offline when near system peak. A "bump" in prices from \$80/MWh to \$10,000/MWh is likely to change market participants' behavior.[11]

Continuing my "Cat in the Hat" analogy, it is time for Cat in the Hats B, C, and D to appear.

"Cat in the Hat B": Resource Optimality

If we expect prices to lead to resource development, shifting the demand curve is a dangerous step. In the final analysis, we would like to meet actual demand, not a hypothetical construction designed by well-meaning economists or bureaucrats. While we often forget past errors, it is wise to remember that California's PURPA misadventure was based on gerrymandering the price paid to PURPA developers – resulting in a prolonged surplus and a massive rate shock for California's ratepayers.[12]

As mentioned above, we can avoid the massive increase in market volatility by reducing the arbitrary scarcity payment. Unfortunately, the producer's surplus is effectively a rectangle. A lower operating reserves price means an increase in the number of times the market must pay the reserves price. If we reduce the price to \$1,000/MWh, the expected hours the market will pay this increase slightly more than tenfold. When there are more hours in which spot prices are greater than or equal to the peakers' marginal cost, the further we depart from an optimal system.

"Cat in the Hat C": Volatility

Advocates of administered markets often neglect to address price volatility. Such volatility affects the market in two significant ways. First, resource developers pay more for capital when operating in a volatile market. One reason why peakers are not a good choice in restructured markets is the difficulty of convincing investors that profitability depends on a very few hours in the year.

Although Dr. Joskow's example does not consider the capital cost implications of increasing price volatility, it is not unlikely to assume that a peaker's capital costs could increase by 50% when volatility increases from 58% to 637%, especially when the change in volatility has been administered by a regulatory agency. A change from \$80,000/MW/Year to \$120,000/MW/Year drives major changes in the optimal resource portfolio, reducing peakers from 2,435 MW to 1,218 MW. The difference is made up in more expensive intermediate resources.

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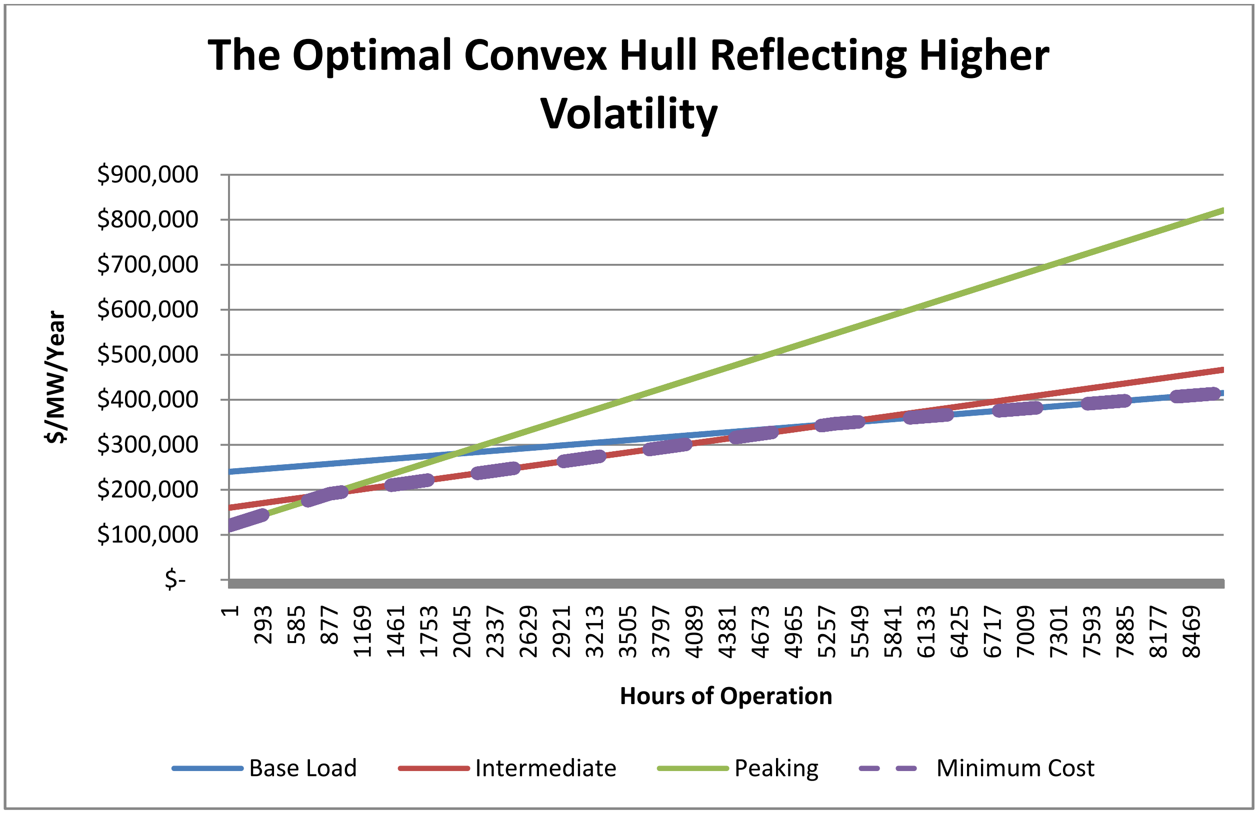
[10] In Dr. Hogan's defense, the volatility is largely related to an arbitrary value of \$10,000 used to price scarcity. As the scarcity value is lowered, the volatility will decrease, but the departure from optimality will increase.

[11] It is always wise to keep in mind Adam Smith's sagacious comment that "People of the same trade seldom meet together, even for merriment and diversion, but the conversation ends in a conspiracy against the public, or in some contrivance to raise prices."

[12] A major motivation for California's restructuring was the high prices caused by the high PURPA prices paid in the 1980s and early 1990s. While the prices were designed by the best technicians, the fact is that they were considerably higher than they should have been.



Volatility is a cost on the demand side as well. During the Western Market Crisis of 2000-2001, the dramatic increase in volatility gradually eliminated the availability of hedges in the market. Open interests at the two NYMEX forward markets reached zero by December 2000, no surprise, since risk capital is a finite resource (the risk managers who provide risk capital will allocate it to markets with least risk).

Another way to explain the impacts of volatility is to assume that Dr. Hogan enters the grocery business in your town. He tells his checkout staff to flip a coin as the customer prepares to pay: heads the groceries are free, tails the charges double. Even though your grocery bill might be unchanged at the end of the year, the risk to your weekly food budget would be severely discouraging. Customers would avoid this store in favor of one with a more traditional pricing policy. Wholesale suppliers would doubt the viability of such an enterprise and require additional credit support before selling their products to it.

“Cat in the Hat D”: Market Power

In a short paragraph, “Acting in Time: Regulating Wholesale Electricity Markets” dismisses the issue of increased market power:

> The operating reserve demand curve is not likely to eliminate concerns about market power. Hence, the preferred little “r” methods of mitigation through the use of offer caps would continue to apply. But with the operating reserve demand curve there would be no need to raise offer caps in order to better approximate scarcity prices.

> Unlike the plan in Texas and the practice in Australia, more realistic scarcity pricing would not require higher or no limits on the offers by generators. Scarcity pricing would be driven by the operating reserve demand curve and not solely by the generators' offers. This would remove ambiguity from the analysis of high prices and distinguish (inefficient) economic withholding through high offers from (efficient) scarcity pricing derived from the operating reserve demand curve.[13]

Having the market administrator meddle with prices will not remove ambiguity. The incentives that scarcity pricing creates for market participants by themselves create ambiguity even before implementing arbitrary shifts in the demand curve. The reality is that even smaller generators will perceive the tremendous returns to withholding as the system reaches capacity. When reviewing the now-infamous Enron trader tapes, Dr. Carl Pechman discovered the following discussion between an Enron trader and a generator under Enron's control:

> TRADER: - ah, we want you guys to get a little creative -
> GENERATOR: OK.
> TRADER: - and come up with a reason to go down.
> GENERATOR: OK.
> TRADER: Anything you want to do over there? Any-
> GENERATOR: Ah-
> TRADER: - cleaning, anything like that?
> GENERATOR: Yeah. Yeah. There's some stuff that we could be doin' tonight.
> TRADER: That's good.
> GENERATOR: Right.
> TRADER: It's supposed to be, ah, you know, kinda one of those things.
> GENERATOR: OK, so we're just comin' down for some maintenance, like a forced outage type thing?
> TRADER: Right.
> GENERATOR: And that's cool.
> TRADER: Hopefully.
> [they laugh]
> GENERATOR: 'Cause the - the schedule I just got over here - well, you know what it says.
> TRADER: Yes. I'm lookin' right at it.
> GENERATOR: OK, it's the new schedule.
> TRADER: You just got a new one?
> GENERATOR: It says 'New Schedule' on the bottom. It's showin' 52 all day.
> TRADER: Oh, right. And so that's the one you're gonna want to ignore.
> GENERATOR: Exactly.
> TRADER: [laughs]
> GENERATOR: OK.
> TRADER: Yeah. So-

[13] Acting in Time: Regulating Wholesale Electricity Markets, William W. Hogan, May 8, 2007, page 14.

GENERATOR: We'll take care of that.
TRADER: So you got a - so you're checkin' a switch on the steam turbine.
GENERATOR: Yeah, and whatever adjustment he makes today, is probably - tonight, is probably not gonna work, so we're probably gonna have to check it tomorrow afternoon again.
TRADER: I think that's a good plan, Generator.
GENERATOR: All right.
TRADER: I knew I could count on you.
GENERATOR: No problem.[14]

This conversation reflects the fact that when near system peak, even a small generator can contribute to a significant change in prices.

The following formula describes a generator's calculation when a significant increase in prices is possible due to a reduction in output:

(Scarcity Price–Marginal Cost) x (1–Withholding%) > Competitive Price–Marginal Cost

In Dr. Joskow's example, shifting from $80/MWh to $10,000/MWh would meet this decision rule for withholding at any level below 100% for peakers to a mere 99.4% for base load resources. The greater the scarcity price imposed by market administrators, the greater the incentive for market participants to "nudge" the market from competitive to scarcity pricing.

Looking for the "Voom"

Unlike the Cat in the Hat, we can learn from history. Energy markets in the Western Interconnection have been based on the simple, transparent WSPP model since the 1980s. In 1994, water flows and reserves were low when the region suddenly suffered a major reliability disaster in the form of an earthquake that leveled the southern terminus of the DC intertie. However, prices remained stable and reflected underlying marginal costs, no emergency declarations were required, and the Western system weathered the situation with few disruptions.

In 2000-2001, substantially less exacting conditions created a situation during which California's Independent System Operator declared more than one hundred emergencies, and major industries in the Pacific Northwest shut their doors forever. What was different?

1. California's "Better Reliability Through Markets" turned out to be a poor method to purchase capacity. Restrictions on the options available to the California ISO (the sole buyer) changed the ISO into a price taker in an extremely adverse market.
2. Availability of capacity from resources within CAISO's service territory declined precipitously. The five major merchant generators averaged a miserable 52% of capacity during the emergency declarations in 2000 and 2001.

[14] Docket EL03-180 et al, Exhibit Snohomish 525, conversation between an Enron trader in Portland, Oregon, and an employee of Las Vegas Cogeneration during a Stage 3 Emergency that CAISO declared in 2001.

3. Capacity responsibility suffered a significant “tragedy of the commons” where no one was ultimately responsible for system reliability. We learned the hard way that an ISO has no stockholders, no voters, and no regulators.

It is important to note that *none* of the problems California faced in 2000-2001 took place in 1994. Yet in 1994, the efficient WSPP market operated without governmental intervention. Because capacity requirements were decentralized, it would have been useless to maneuver capacity shortage declarations through the use of Ricochets, Load Shifts, and suspicious forced outages.

Open markets in energy have existed in the United States for over twenty years. They have worked transparently and efficiently. Intervening to “fix” them so as to approximate capacity markets is likely both to fail and to create a host of follow-on difficulties.

California’s experiences demonstrate that centralized capacity markets, especially those where rules have been enacted to forbid purchasing capacity in an efficient manner, do not really work very well, and are hugely expensive to implement, operate, and maintain.

”Voom” on the other hand is a laudable goal, and I believe that there are merits in retaining the “de” in deregulation and in discouraging increased intervention in markets. Like the Cat in the Hat’s shenanigans, Dr. Hogan’s solutions are interesting, but take us further away from competitive solutions.

Appendix:

Why the Missing Money Problem affects all resource owners:

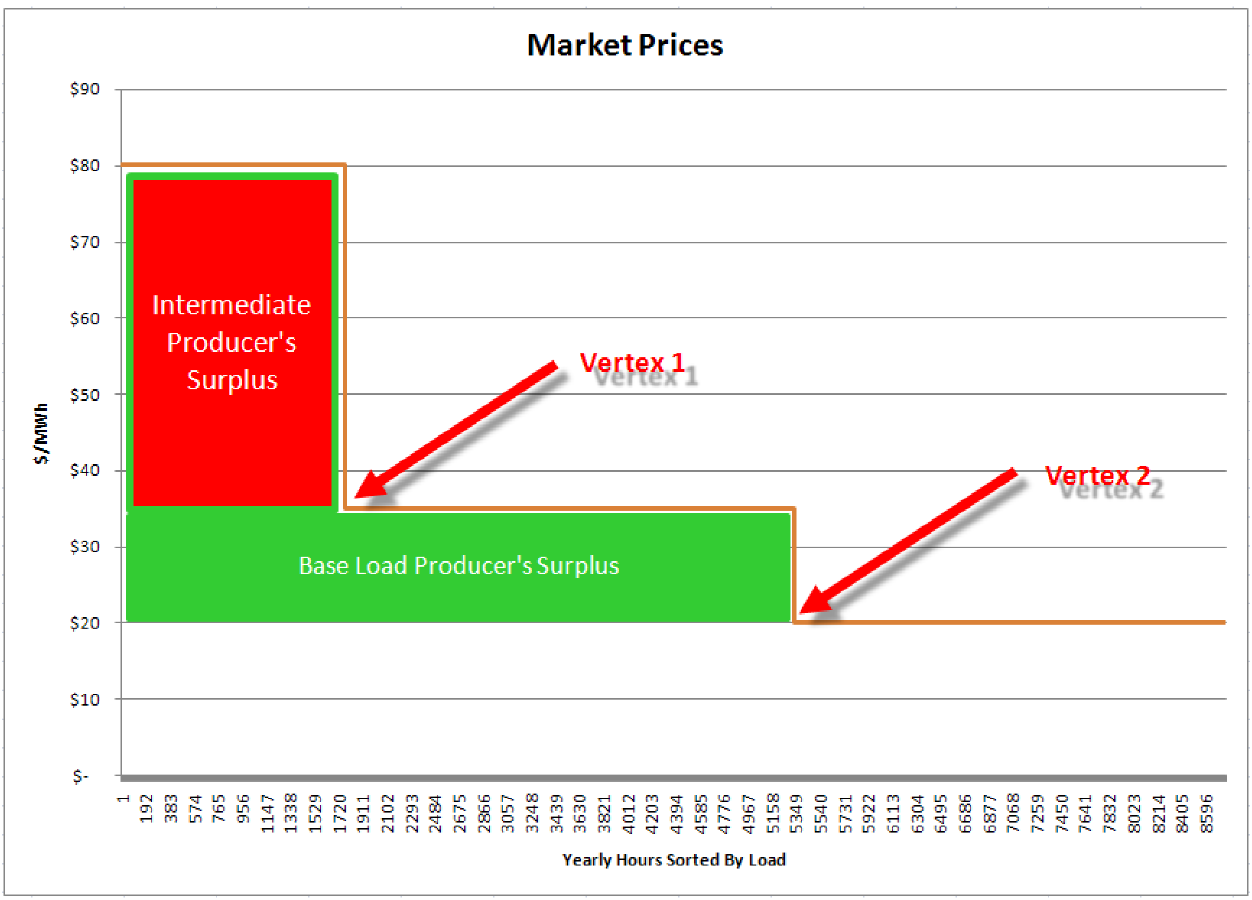
The convex hull identifies i vertices. Each vertice is the intersection between two lines: the ith total cost line and i+1th total cost line. Total Cost(TC)=Fixed Costs(FC)+Hours of Operation(Hours)xVariable Cost (VC). The intersection occurs at the number of hours where $FC_i+VC_i xHours=FC_{i+1}+VC_{i+1} xHours_j$.

We can solve for the Hours corresponding to each vertex on the optimal convex hull by collecting terms and dividing. This gives $Hours_j=(FC_i-FC_{i+1})/(VC_{i+1}-VC_i)$.

A new resource will earn revenues towards its fixed cost only when prices are above its variable cost. Another way to say this is that the most expensive resource will not expect to capture any producer's surplus since the highest price, at load resource balance, is just equal to its variable cost.

The next highest variable cost resource will receive a contribution towards its fixed cost when prices are above its variable cost.

We can see this clearly using Dr. Joskow's example:



In this example, peakers set the market prices for the highest load hours. Peakers' owners will just cover their variable costs during this period. Their expected loss is just equal to the fixed costs of a peaker.

The intermediate resource owner fares better. Its producer's surplus is equal to the red box. Algebraically, the size of this box is $(VC_i\text{-}VC_{i+1})$x Vertex 1, and Vertex 1 is $(FC_i–FC_{i+1})/(VC_{i+1}–VC_i)$. When we simplify the expression we find that the intermediate resource owners' producer surplus is equal to $FC_2–FC_1$. The intermediate resource owners' shortfall is just equal to the fixed cost of a peaker.

What about the next resource? The total producer's surplus for each succeeding resource is equal to the sum of the previous resource owner's producer surplus plus the additional surplus provided by their lower variable cost. In this case, the size of the red box is $FC_2–FC_1$. The size of the green box is $FC_3–FC_2$.

The sum of these two boxes is $FC_3–FC_1$. The base load resource owner also has a shortfall of the fixed cost of a peaker.

In the general case, the producer's surplus of resource owner i is $FC_1–FC_i$. When we add the additional revenues above variable cost for the next resource owner, they are $FC_{i+1}–FC_i$ so that the total producers' surplus is $FC_{i+1}–FC_1$.

A revenue shortfall is built into the energy only market for every resource owner regardless of the number of different resource types in the analysis.