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WHY THE ANCILLARY SERVICES MARKETS IN CALIFORNIA DON'T WORK AND WHAT TO DO ABOUT IT

By

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I. INTRODUCTION

Many states and regional Power Pools are in the process of introducing or broadening the scope of competitive electricity markets. Many varied market designs have been proposed. Most of these efforts, however, have focussed on launching competition into the energy market. The energy market is perceived to be the big-ticket item in this process. Most of the dollars are to be made in this market, and this is the area where wholesale competition already exists. But, ancillary services cannot be ignored in this process. Each newly competitive market needs to put in place a way to deal with ancillary services in the new world.

This article sets out to examine the physical and financial realities of the electric system that need to be taken into account when designing markets for ancillary services. It looks at the market structure in California, the evidence to date there, and proposes ways to improve the market design.

The context for this analysis is the events seen in California in the summer of 1998. On July 12, prices for replacement power delivered on July 13 spiked to $9,999/MWh for the hours between 2 and 6 p.m. It is rumored that the ISO paid *approximately $5 million* for these reserves, as opposed to $1500 under the IOU bid cap rates.[i] The ISO subsequently imposed a price cap of $500/MWh, later reduced to $250/MWh.

Clearly the markets were not functioning competitively. The problems observed in the market appear to have risen from three sources –the role of bid caps, market power in the supply of ancillary services, and the trading arrangements in the markets. FERC[ii] has removed the first problem by permitting all sellers to earn market-based rates. It hopes to resolve the other two problems by redesigning the markets. To do so, it has told the ISO to resubmit a comprehensive market redesign proposal by March 1999.

II. MARKETS FOR ANCILLARY SERVICES

A. What Are Ancillary Services?

Customers consume electricity in a precise location, at a precise time. Electricity is a bundled product. The "raw" energy, traded in the spot energy market, has been refined by combining it with other services, to produce the stable and reliable electricity supply required by customers. The additional or ***ancillary*** services customers require include:

- a stable frequency;
- a stable voltage; and

- The option to take or dump energy at short notice.

In California, the ISO has defined six ancillary services necessary for the secure and reliable operation of the transmission system. These are:

- ***Regulation* –** service provided by generating units equipped and operating with AGC which will enable such units to respond to the ISO's direct digital control signals in an upward and downward direction to match, on a real time basis, demand and resources…[iii]
- ***Spinning Reserve* –** the portion of unloaded synchronized generating capacity, controlled by the ISO, that is capable of being loaded in ten minutes, and that is capable of running for at least two hours;
- ***Non-Spinning Reserve* –** portion of off-line generating capacity or that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours;
- ***Replacement Reserve* –** generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ramping to a specified load point within a sixty minute period, the output of which can be maintained for a two hour period. Also, dispatchable demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours;
- ***Voltage Support:*** services provided by generating units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria; and
- ***Black-start Capability***: procedure by which a generating unit self-starts without an external source of electricity thereby restoring power to the ISO controlled grid following system or local area blackouts

The remainder of this paper will concentrate on the first four services listed above – regulation, spinning reserve, non-spinning reserve, and replacement reserve.[iv] These are the services the ISO buys on an hourly basis each day.

B. Why is A Properly Functioning Market For Ancillary Services Important?

The aim of designing a market needs to include, among other factors, a desire for efficiency. Efficiency means ensuring that the lowest priced resources are used to meet demand. What role do ancillary services play in this process? After all, ancillary services comprise only a small portion of the overall dollars in the electric market. The thinking has been that most of the time and effort should be spent on making sure that the energy market works well. This could be a false economy of effort. Assuming that a less than efficiently operating market for ancillary services will not be costly ignores many aspects of the industry.

When creating markets for ancillary service, it is crucial to understand both the links between generating and providing ancillary services and the options and the aims of plant owners when selling into these two markets. How ancillary services are bought affects both the prices for ancillary services and the prices in the energy market for the these reasons:

- In the short term, how ancillary services are bought will affect the amount of resources to be had on the system. Ancillary services and energy are substitutable products. Generating capacity allocated to supply energy is not available to supply ancillary services and vice versa. The incentives created in the design of ancillary services markets, therefore, will affect the amount of capacity available. This in turn will impact hence the prices in the energy market; and

- How ancillary services are bought will affect the efficiency of scheduling and dispatch of generating plant. In the longer term this will affect prices, availability and new investment. If the choice of units is not efficient, then prices will either exceed or fall below their equilibrium levels. This in turn will affect the incentives to invest in new plant or shut existing plant.

Historically, the utilities used unit commitment algorithms to decide which plants will provide energy and ancillary services. The aim of these programs is to minimize the total cost of meeting demand and ancillary service needs. With the launch of competition, market incentives replace the traditional utility regime. Generators can decide when they operate in response to market signals. They can decide into which market they wish to sell their output. If they are not limited as to what they can do, they will sell to the markets with the highest returns. If a plant can earn market revenues from sales of energy, but only regulated prices from sales of ancillary services, the owner's incentive is to sell all its output into the energy market. This, of course, assumes that the market prices would be greater than the regulated prices. This gap in payment would lead to a shortfall in supply of ancillary services, if the regulated rates could not respond to market forces. A shortfall in ancillary services could lead to reliability problems on the grid. . A competitive market for energy, therefore, requires a competitive market for ancillary services. This is needed to provide incentives for suppliers to offer ancillary services.

C. Physical and Financial Realities of Providing Ancillary Services

To operate the electric system at least cost, the market must take into account both the physical and financial realities of generating plants. These "physical realities" include the need for some of these services, e.g., spinning reserve and regulation, to be supplied by on-line generation. Also, energy and reserves are substitutable products. Financially, the two markets are also linked.

1. Substitutable Products

At any one time, the maximum amount of output a generator can provide is fixed at the capacity of the unit.[v] This capacity can be split between energy and reserves. Hence, reserves and energy are substitutable products, from the point of view of the generating unit. They can sell one or the other, but not both at the same time, from the same block of capacity. For system operation to be efficient, the capacity of each generating unit needs to be split appropriately between the two markets. If the markets are divided, allocating plants efficiently between the energy and reserves is much more complex.

2. On-Line Generation Requirements

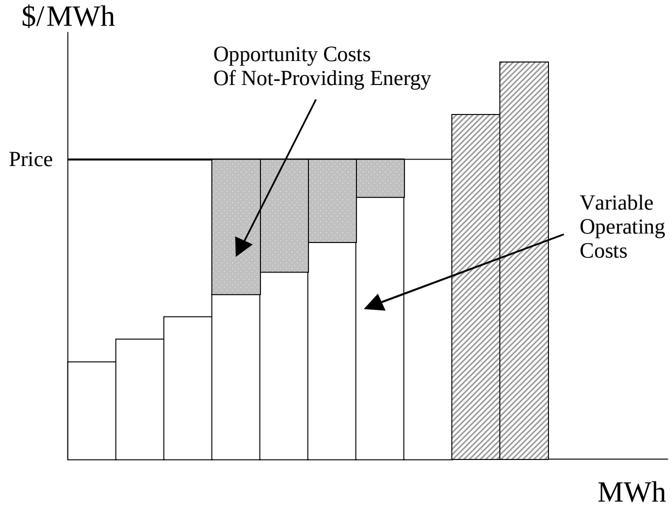
Two ancillary services, regulation and spinning reserve, can only be provided by on-line generators.[vi] These are stations that are synchronized to the system and producing at least some minimum level of output. The decision to operate a unit for ancillary services cannot, therefore, be isolated from operating the unit to produce energy. On-line ancillary services and energy are joint products. You cannot get one without the other. Bringing an off-line unit on-line to provide regulation will require changes to the generation levels of other units to balance supply and demand. This will change the marginal unit in the energy market.

3. Cost of Providing Ancillary Services

The financial links between generating and supplying reserves will also affect the way markets for ancillary services are structured. A generator selling reserves must forgo the profit from generating from that portion of capacity. The cost of supplying reserves, therefore, is the opportunity cost of not providing energy. For example, a generator has a variable cost of producing energy of $20/MWh. When the price is $30/MWh, the generator has an opportunity cost of selling reserves equal to $10/MWh. This is the profit it would make on selling into the energy market. The minimum price a generator would accept for supplying reserves would be $10/MWh. Below that price they would prefer to provide energy rather than reserves. Above that price, they would prefer sell more reserves, and sell less energy. This is shown by the dark shaded area in Figure II-1. This shaded area shows the supply curve for providing reserves from infra-marginal generators. If the generator has on-line generating capacity that was not competitive in the energy market, then the cost of providing reserves is zero. This is shown by the light shaded area in Figure II-1.[vii]

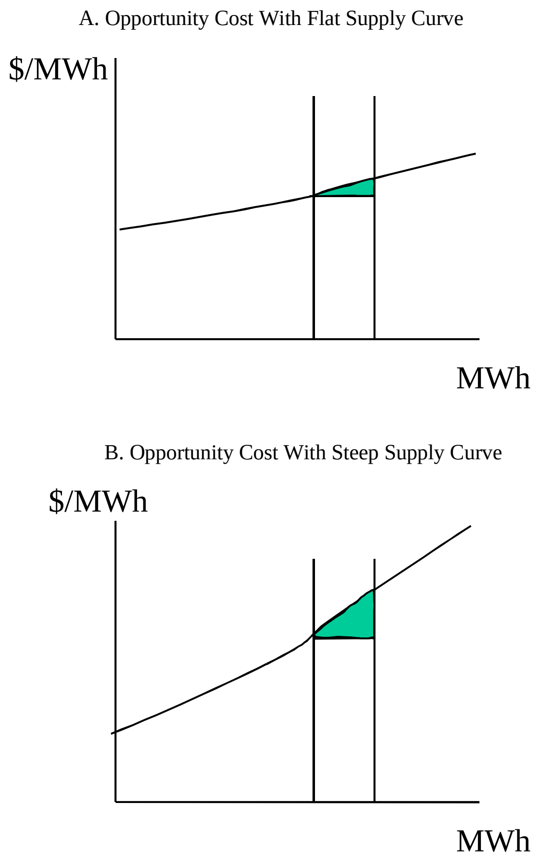
Efficient scheduling and dispatch of generation, therefore, needs to examine the economic tradeoffs from switching energy and reserves between generating plants.[viii] Ignoring the links between the costs in one market and prices in the other will lead to misallocation of resources between the two markets. This will create scarcity in one coupled with over-supply in the other.

Figure II-1 Cost of Providing Ancillary Services



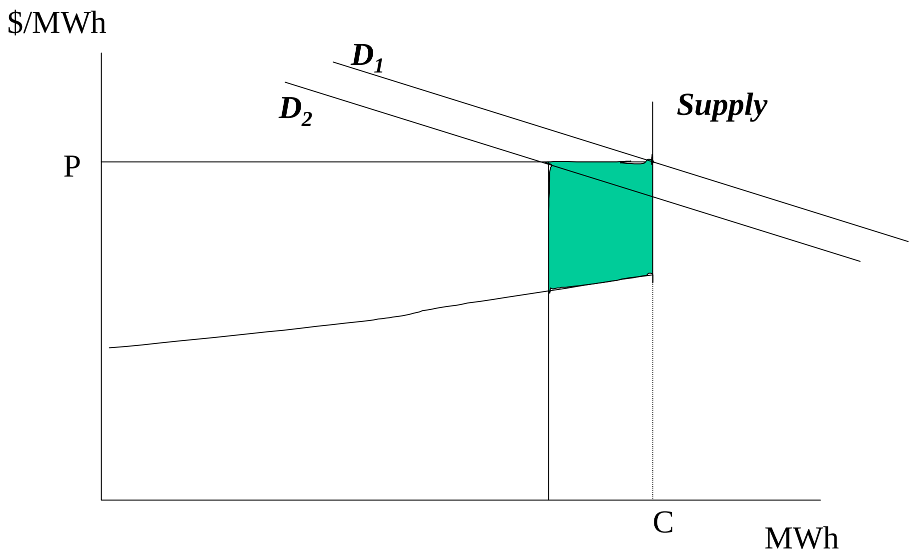
The price for reserves should be low in a competitive market. When the supply curve is flat, and the energy market clears at the last supply bid, as shown in Figure II-2, A, the price for spinning reserve should be close to zero. When the supply curve is steeper, as shown by B below, the opportunity cost of supplying ancillary services increases, and so would the prices for reserves. It would still be significantly below the energy market price.

Figure II-2 Supply Curve For Ancillary Services



When supply is constrained, as represented by the vertical portion of the supply curve in Figure II-3, the price will be set by demand bids. The price will rise to ration the supply to the available demand. With a higher price in the energy market, the opportunity cost for generators supplying reserves increases. This is shown by the shaded area in Figure II-3. The same principles hold for prices of non-spinning and replacement reserves. The prices for regulation should be somewhat higher, since units providing regulation have higher overall costs. These higher costs are due to the additional fuel and wear and tear costs from ramping the units up and down.

Figure II-3 Opportunity Cost Of Supplying Reserves When Capacity Is Constrained



Overall, however, we would expect the prices for energy and ancillary services to move in tandem. When demand in the energy market is low, and prices are set at the flat point of the supply curve, reserve prices should also be low. When energy prices increase, particularly when generation supply is constrained, then reserve prices should also increase.

III. THE CALIFORNIA EXPERIMENT

A. Overview

The markets for ancillary services in California can be described in two words – separate and sequential. The Independent System Operator (ISO) must ensure that enough ancillary services are on hand to operate the grid in a secure and reliable manner. Scheduling coordinators can self-provide their ancillary services needs. Alternatively, the ISO can buy services for them. It does this by organizing competitive markets for ancillary services. Regulation, Spinning Reserve, Non-spinning Reserve and Replacement Reserve are bought on a daily basis.

All markets take place in sequence. The ISO operates a separate market for each of four ancillary services. The ISO begins analyzing the bids for ancillary services after receipt of the energy schedules. [ix] The ISO begins with the capacity bid into the regulation market. Each of the three reserves markets follow in turn. Any generation capacity that was not chosen in one market may, at the request of the owner, be passed onto the next market.

B. Evidence of Market Failure

One way to examine how efficiently a market operates is to compare the actual prices in the market with the expected prices in an efficient market. In a competitive market for ancillary services, what prices would be expected? As we discussed above, the cost of providing reserves reflects opportunity cost of providing energy. The price for reserve should equal the cost of the marginal supplier. Then, the expected prices in the ancillary services markets should equal the marginal opportunity cost of foregone energy sales. In no case should the price for reserves exceed the actual energy prices.

Table 1 shows that the actual prices for ancillary services in California from April through August differ substantially from expectations. In April and May, no generating companies were permitted to sell at market based rates. Prices were set, therefore, based on the bid caps for each unit. On June 30, 1998 FERC granted market based rates for 3 generation plants in Southern California – Alamitos, Redondo Beach, and Huntington Beach. On July 10, 1998, FERC granted market-based rates for Long Beach, El Segundo, Ormond Beach and Etiwanda, Mandalay and Coolwater, owned by Houston Industries. In these orders, FERC also stated that replacement reserve was not an ancillary service. Sellers did not need authorization from FERC to sell at market rates.

All of the units permitted to earn market-based rates are located in the Southern California transmission zone (SP15). Table 1 shows how the prices for the services rose in the Southern California zone, following the granting of market based rates. For example, replacement reserves reached $5,000/MWh on the trading day of July 8 for power delivered on the 9th. From 1 to 6 p.m. prices were as follows: 2,500, 5,000, 5,000, 5,000, 750 ($/MWh). The capacity involved is estimated to have been between 300 and 500 MW. Following two weeks of dramatic price spikes, when prices rose to the software imposed cap of $9999, the ISO on July 17th imposed a price cap of $500 in all the ancillary services markets. While prices fell from their pre-cap highs, they frequently reached the new cap. On July 24th, the ISO lowered the cap to $250/MWh.

How do these prices compare to prices in the energy markets? As discussed above, we expect that prices for energy and ancillary services should move in tandem, since the cost of providing one is the opportunity cost of not providing the other. The prices in Table 1 show that, in most cases, the average monthly ancillary services prices for each service exceeded the average monthly PX energy prices.

Table 1: California Market Prices

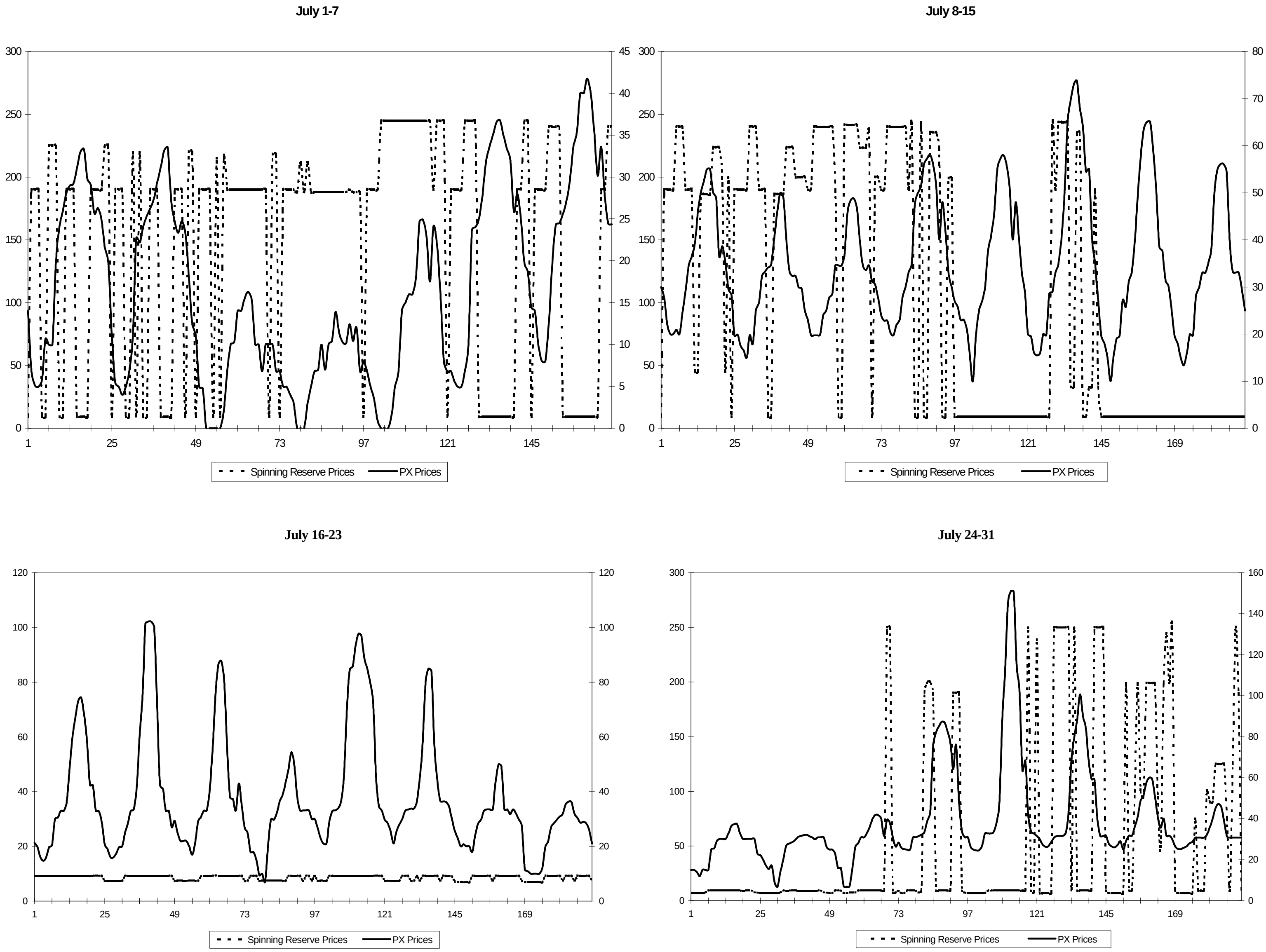
On Peak	April	May	June	July: Pre Price Cap	July: Post Price Cap	August
Spin Reserves						
NP15	7.90	7.51	38.83	7.37	25.78	
SP15	7.90	7.51	48.46	130.50	35.96	63.99
Non Spin Reserves						
NP15	7.20	7.72	3.54	7.66	39.04	
SP15	7.20	7.72	3.29	3.18	44.53	48.70
Replacement						
NP15	8.02	7.93	4.28	6.27	44.72	
SP15	8.02	7.92	4.03	323.82	46.96	51.58
Regulation						
NP15	11.55	9.33	19.63	6.36	24.36	
SP15	11.55	9.33	20.12	55.16	31.25	13.63
PX Day Ahead Price	25.68	14.76	16.11	30.96	44.95	47.39

Off Peak	April	May	June	July: Pre Price Cap	July: Post Price Cap	August
Spin Reserves						
NP15	7.44	7.45	21.79	7.26	14.11	
SP15	7.44	7.45	21.83	141.43	17.62	22.70
Non Spin Reserves						
NP15	6.08	6.45	2.56	7.42	4.97	
SP15	6.08	6.45	2.56	2.92	5.10	13.83
Replacement						
NP15	7.70	7.90	2.89	5.94	3.27	
SP15	7.70	7.90	2.89	2.97	2.16	1.95
Regulation						
NP15	11.56	9.70	61.69	7.47	47.91	
SP15	11.56	9.70	62.65	125.27	60.00	23.27
PX Day Ahead Price	16.52	5.42	4.05	15.47	23.7	23.79

Source: California ISO data.
Notes:
NP15 = North of Path 15 congestion zone
SP15 = South of Path 15 congestion zone

The following figure shows the hourly PX energy and ancillary services prices during July 1998 in California. In general, there was little link between the prices for energy and spinning reserve in July 1998. The days with the highest observed energy prices were the same days with the lowest spinning reserve prices. In the week of July 16-23, with high on peak energy prices, the price for spinning reserve remained at the level of bid caps. The following week, energy prices increased slightly but the price for spinning reserve rose to $250/MWh in some hours, the level of the new cap introduced on July 24. Overall, the graphs show few links between the price for energy and the price for spinning reserve.

Figure III-1 Energy and Spinning Reserve Prices, July 1998



C. Reasons for Market Failure

The recent reports by the ISO Market Surveillance Committee (MSC)[x] and the PX Market Monitoring Committee have both outlined a number of reasons for the unexpectedly high prices observed in California last summer. These included:

- Some firms were subject to bid caps while others were allowed to earn market-based rates;
- The demand for ancillary services was higher than expected;
- Perverse incentives for generator bidding behavior created by reliability must-run contracts;

There are additional structural features in the California market, which will also drive the operation of the market. These are the sequential and separate nature of the markets. The sequential nature of the ancillary services auctions created a number of problems in the market, and is discussed in detail elsewhere.[xi] One little discussed issue is the problems from the separation of the market for ancillary services from the market for energy.

1. The Markets For Ancillary Services Ignore The Interactions with the Energy Markets

The California market for ancillary services explicitly divides the choice of suppliers in the energy and ancillary services markets. The ISO selects all units in its ancillary services auctions independently of the energy schedules. This separate approach limits the ability of the market to work well and minimize the cost of meeting load.

First, the energy market closes prior to the start of the ancillary services markets. This makes it complex to allocate resources efficiently for the system as a whole. Infra-marginal suppliers in the energy market must replace sales of ancillary services for sales of energy at the market price. If the ISO were to reserve capacity from these infra-marginal suppliers, they would be replaced in the energy market by bidders that had been extra-marginal. Costs overall could be reduced by making changes such as these. The ISO, though, is barred from doing this. Unless all bidders in the energy and ancillary services auctions have correctly estimated the prices in all markets and assigned capacity correctly, overall prices will be higher under this approach.

Second, the ISO must ignore any minimum energy output of a plant when it chooses plants in its auctions.[xii] Plants providing regulation and spinning reserves must be on-line and generating. Otherwise, they cannot supply the services. In the past, utilities combined the choice of units to provide energy and ancillary services to ensure that there was always enough unloaded capacity on-line to provide reserves. If there were not, they would re-evaluate the choice, and adjust if necessary. Now, capacity is first offered into the energy market. If generators try to sell as much energy output as possible, there will be fewer generators with unloaded capacity available to sell reserves. This raises the odds that some plants must start-up explicitly to provide spinning reserve and regulation. All these plants will have some minimum output level. This minimum output level will have a cost to produce. The generator will want to recover this cost if selected for ancillary services. By barring the ISO from taking this factor into account when evaluating bids, the generators must take all the risks of covering these costs. Generators may not want to supply ancillary services under these conditions. The structure of the market, therefore, worsens the other market features by reducing the amount of capacity bid into the market. This in turn pushes up prices.

2. Coherent Pricing Between The Markets Is Difficult, If Not Impossible

Consistent pricing between markets for reserves and the energy market is essential for the market to work well. If the markets have no link with one another, with the energy market taking place first, the price of reserves may never equilibrate to the opportunity cost of foregone energy sales.

The California market for ancillary services explicitly divides the choice of units in the energy and ancillary services markets. The ISO chooses units to provide all on-line ancillary services entirely separately of the choice of units to provide energy. The energy market closes prior to the start of the ancillary services markets. The appeal for plants that are risk averse will be to sell as much output as possible in the energy market. If their offers fall short, they could then sell any additional capacity as ancillary services. The drawback to this approach is that it limits the capacity available in later markets.

IV. WHY DID CALIFORNIA ADOPT SEQUENTIAL AND SEPARATE MARKETS FOR ANCILLARY SERVICES?

In its Order 888, FERC included ancillary services as a component of the Open Access Transmission Tariffs (OATT)[xiii]. Its aim was to separate ancillary services from transmission service so as to promote competition in the supply of ancillary services:

> "*Unbundling ancillary services will promote competition and efficiency in their supply. Because most generation-based ancillary services potentially can be provided by many of the generators connected to the transmission system, some customers may be able to provide or procure such services more economically than the transmission provider can. Once they are unbundled, a more competitive market may emerge to supply such services.*
>
> *Also, unbundling makes possible a more equitable distribution of costs. Because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission concludes that the six required ancillary services should not be bundled with basic transmission service.*"

The FERC wanted these services to be unbundled from transmission service and offered separately by the grid owner. Within the OATT, transmission users are free to either self-provide these services, buy from a third party or buy from the grid owner. In turn, the grid owner must offer services to all users at tariff rates. The aim of unbundling the charges for ancillary services from the charges for grid usage was to ensure that grid users did not have to take these services from the grid owner. In this way, control over a monopoly service, transmission, would not lead to control over ancillary services. These in turn could be competitively offered. In its Order 888 FERC did not proscribe any precise market format for these services or any precise link between the markets for energy and for ancillary services.

There are two aspects of ancillary services markets that are of concern here. The first is the structure of the markets. This describes how generation units and dispatchable load facilities can be chosen to provide these services. The second issue is how are charges for ancillary service identified, calculated, and recovered from the grid users. Charges are usually calculated by taking the total costs of the service and dividing this amount by some charging basis. This is wholly separate from the means for buying the services. This message, that these ***charges*** should be unbundled from the charges for transmission service, got lost in the morass of market design of the PX and ISO in California. The goal was to provide options for grid users to meet their ancillary service needs, without having to take them solely from the grid owner. Recent events, including the ISO and Power Exchange (PX) filings in California[xiv], have taken this concept a step further. The goal moved from unbundled charges for ancillary services, identified separately from the charges for transmission service, to unbundling the selection of ancillary services from the selection of units in the energy market.

This came about for a variety of reasons. The design process consisted of noisy debates between power marketers, commercial and industrial customers, as well as the companies that had been running the electricity system – Southern California Edison, San Diego Gas & Electric and Pacific Gas & Electric.[xv] Many of the power marketers came out of the gas sector and had limited experience of the electric sector. Crucially, the system controllers or power engineers who actually ran the system did not make the decisions. Instead, decisions were made by large groups of stakeholders. This group may not have appreciated the physical and financial links between the markets.

V. IF SEPARATE MARKETS DON'T WORK, WHAT WOULD?

Clearly, the market for ancillary services in California is not working as intended. The price for the services bought on a daily basis by the ISO far exceed the opportunity cost of foregone energy sales. FERC has requested the California ISO to redesign the ancillary services market, no later than March 1st, 1999. This section puts forward some proposals to be considered in this process.

A. Coordinate The Selection Of Suppliers Between The Energy and the Markets For On-line Ancillary Services

The efficiency of all markets could be improved by coordinating the scheduling of units across all markets for both energy and ancillary services. The selection of units to provide energy should not be fixed until the ISO runs its auctions for ancillary services.[xvi]

This is the approach used in both the England and Wales Pool[xvii] and the PJM ISO for on-line reserves[xviii] and frequency control or regulation. Plants submit offers for capacity available to be dispatched. The offers do not distinguish between capacity offered for energy or for reserves. The ISO (in PJM) or NGC (in England and Wales) assign capacity to each service based on offer prices. Units will be chosen so as to minimize the cost of providing both these services. The choice automatically takes into account the impact of constraining on or off units and allocating loaded or unloaded capacity to the most suitable units. The units with the lowest energy offers and the highest value from generating will be scheduled to generate. Similarly, reserves would be assigned to the units with the lowest cost of providing reserves. These would be the units with the highest energy offers or lowest opportunity costs.

By taking all factors into account when choosing plants, the choice of units should be efficient. It is not possible to select alternate units that would lower costs. Suppliers are confident that if their offer to supply either service is selected any joint costs of providing both services will be covered. They do not need to manage this risk through their bids. Just as it would not be possible to increase overall efficiency by selecting alternate units, no individual unit could be better off by altering its proposed mix of energy and ancillary services. No supplier has an incentive to try to switch between supplying energy and ancillary services. This is because each plant, which submitted an offer, has been chosen to provide either energy or other services, to maximize each supplier's profits.

A second best solution to this in the California context may be to allow the ISO to use the adjustment bids for managing congestion, to also adjust schedules to provide ancillary services, such as reserves.

The problem in California is made worse by the fact that no entity has an incentive to minimize the overall cost of meeting energy and ancillary service demand. The PX meets the energy demand in the market at least cost, while the ISO is charged with minimizing the costs of ancillary services. In England and Wales, NGC has an incentive to select units to minimize the total costs of both energy and ancillary services needs. This incentive scheme goes under the name of the "Transmission Service Scheme". It has been in operation since 1994 (under this and other names).

The bundling of the markets for energy and ancillary services does not preclude separate unbundled charges for ancillary services. These charges can be separated from the market price for energy. The extra cost of any constrained-on plant to provide ancillary services, as well as the payments for reserve capacity, can be easily divided from the market price for energy.

These charges could then be recovered through separate ancillary service tariffs, as required by FERC.

B. Consider Long Term Contracts For Off-Line Reserves

Not all ancillary services need to be provided by on-line generating units. In California, off-line generating units can provide both Non-Spinning Reserve and Replacement reserve. Dispatchable load customers can also sell these services. Given this, close coordination with the selection of units in the energy market is not crucial. Services such as these could be bought under long term contracts. This would increase the number of units competing to supply the services.

These contracts could take the form of options contracts. The ISO would buy the option to take energy from the generating unit, or reduce consumption of the dispatchable customer, when required. The winning bidders would receive a fixed payment, perhaps to cover the costs of being available, plus a variable payment when dispatched, to cover the additional generating costs.

This approach is used in England and Wales for standing reserves. These reserves are provided by generating units on hot-standby, open-cycle gas turbine plant, standstill hydro plants and standstill independent non-centrally dispatched generating plant.[xix] NGC buys these services under explicit ancillary services contracts. These contracts last for one year. One criticism of this approach is that it requires the ISO (or NGC) to buy reserves from plants that may not be available when required. NGC got around this problem with a "committed" and "flexible" option. Companies bidding for the service could choose whether to provide a "committed" service. A committed service is one where a commitment is made to provide a minimum level of availability in all time periods. The other option is to offer a "flexible" service where availability could be offered as and when conditions allowed.

C. Consider a Portfolio Approach

One problem with the California ancillary services markets is that bidders are required to bid separately for each market. The ISO selects the winning bidders for each market consecutively. The excess bids are passed onto subsequent markets. Most capacity is available to meet demand in the first market. The capacity in subsequent markets is reduced by the quantity of winning bids in the prior markets. This leads to a perverse outcome, whereby the prices in the most valuable markets, i.e., regulation and spinning reserve are frequently lower than the prices in the less valuable markets, as shown in Table 1.

The way to remove this perverse outcome would be for the ISO to adopt a "Portfolio" or intelligent auction approach. Suppliers would submit bids, indicating the capacity available to supply ancillary services. These bids would not be for a specific service[xx] but to provide "any service". The ISO would then select the least cost units to provide all of services, so as to minimize the overall costs. This "portfolio" approach could be used for types of services -on-line and off-line.

VI. SUMMARY

As more and more states and countries adopt competitive electricity markets, the designers of these markets will look to current markets as a starting point. While the split of functions between the PX and the ISO in California may make it impossible to make the redesign of the ISO markets efficient, other markets can learn from the problems in California.

There are many important lessons from the California market design that may be useful for those setting out on the process electric market design, namely:

1. Keep the markets integrated. Energy and ancillary services cannot be isolated from each other;

2. Keep it simple. The more complex the market design, the more difficult it is achieve an efficient outcome, as well as reliable scheduling and dispatch of generation; and

3. In the design process, listen to the system operators. They know how the system works both physically and financially. The operation of competitive markets should mirror how the system works today.

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[i] California Energy Markets, p. 9, No. 473 (7/17/98).

[ii] United States of America 85 FERC 61,123 FEDERAL ENERGY REGULATORY COMMISSION

[iii] California Independent System Operator Operating Agreement and Tariff" and "California Power Exchange Operating Agreement and Tariff", April 1997.

[iv] Currently, voltage control and black-start are provided by generating units that operate under Reliability Must Run contracts.

[v] While the nameplate capacity of generating units is fixed, the effective capacity can alter due to temperature variations.

[vi] This is a WSCC requirement. In other NERC regions, dispatchable load customers can provide spinning reserves.

[vii] Note that the price for ancillary services only covers the compensation for unloaded capacity. If dispatched, generators are paid for any energy output.

[viii] "Comments on The Report On Market Issues in the California Power Exchange (PX) and The Preliminary Report On Market Operations Of the Ancillary Services Markets Of the California Independent System Operator", P. Joskow, Submitted to FERC.

[ix] The ISO does not have a role in operating energy markets. Generating units are selected to generate by the Power Exchange (PX) and by competing scheduling coordinators. The decision to schedule a particular unit to provide energy is made prior to the selection of units in the ancillary services markets.

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[x] "Preliminary Report On The Operation of The Ancillary Services Markets Of the California Independent System Operator (ISO)", August 19, 1998.

[xi] Comments of Paul Joskow, August 1998.

[xii] " California Independent System Operator Operating Agreement and Tariff", Original Sheet No. 80.

[xiii] "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities," Docket No. RM95-8-000, and "Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Docket No. RM94-7-001

[xiv] " California Independent System Operator Operating Agreement and Tariff" and "California Power Exchange Operating Agreement and Tariff".

[xv] "Contrasts In Restructuring Wholesale Electric Markets: England/Wales, California and the PJM", Alex Henney, Electricity Journal, Volume 11, Number 7.

[xvi] Given the division of responsibilities between the ISO and the PX, as well as other scheduling coordinators, in California, this option may be difficult to implement.

[xvii] While the Pool and OFFER are currently undertaking reviews of the England and Wales market, the current proposals do not include changes in the approach to ancillary service procurement. To date, the type of problems evident in California have not appeared in E&W.

[xviii] NGC calls this service "Scheduled Reserve".

[xix] Report on Reserve For 1995/6, National Grid Company, Ancillary Services Business.

[xx] It would be necessary for the suppliers to indicate their capability to provide particular services, e.g., ramping capability to provide regulation, spinning reserve, etc.