Forcing Reserves to Compete With a Physical Market

Reliability engineers have structured reserve programs to be noncompetitive. As structured, reserve programs are taxing mechanisms, providing a "Get out of jail free card." Reserve programs need to be insurance programs with a physical market metric. As an insurance program, reserves would be forced to compete with the physical market. The physical market must include a cash out of delivery imbalances relative to scheduled deliveries. Such competition would reduce the market power that has been associated with existing reserve programs, such as revealed in the Enron "smoking gun" memos.

Introduction

The electric network needs reserves. Reserves are generating capacity that is in excess of the expected load on the system. Reserves are necessary to meet outages on generating equipment. Reserves also allow the electric system to meet unexpected increases in load.

Electric utilities often find that the least expensive way of obtaining reserves is to interconnect with neighboring utilities. These interconnections take advantage of the diversity between neighboring electric systems. Diversity is the difference in the timing of peak loads and of generator outages.

Under NERC (the North American Electric Reliability Council), regional reliability councils established formulas that set the reserves each utility in the region is required to maintain. Without reserve programs that enforce such formulas, utilities were able to freeload on their inter-ties.

Tie-riding freeloading is possible because there is not yet a cash market for unscheduled flows of electricity. In my first published article thirteen years ago[1], I urged the implementation of a cash physical market for unscheduled flows of electricity. Recently, I again urged the implementation of a cash physical market, this time as the standard market design being considered in a recent Federal Energy Regulatory Commission (FERC) rulemaking.[2]

The movement of the electricity industry toward a competitive market requires a reevaluation of the concept of regional reserve programs. This movement toward a

[1] "Tie Riding Freeloaders--The True Impediment to Transmission Access," *Public Utilities Fortnightly*, 1989 December 21.

[2] See "Initial Comments On Discussion Papers By Mark B. Lively, Utility Economic Engineer", *Electricity Market Design and Structure*, FERC Docket No. RM01-12-000, 2002 April 9; and, "Initial Comments On Working Paper By Mark B. Lively Utility Economic Engineer", *Electricity Market Design and Structure,* FERC Docket No. RM01-12-000, 2002 April 10.

competitive market reinforces my view that the industry needs a way to cash out unscheduled flows of electricity. My view is reinforced by the recent revelations of the Enron “smoking gun” memos, showing the ease with which scheduling can be used to generate abnormal profits.

An Insurance System Versus A Tax System

Many electric industry pundits have explained reserve requirement programs as being akin to insurance programs. Everyone knows that problems will occur on the network. These problems could cause catastrophes. The outage of a generator can require the utility to turn off load. If such loads are not turned off quickly enough, various overloads on equipment can lead to cascading blackouts. An investment in reserves lessens the likelihood that the utility will have to turn off load intentionally, let alone suffer the ignominy of cascading blackouts.

When the utility is viewed on a standalone basis, a reserve program can be considered to be an insurance program. The similarities are many. The continuing cost of owning the reserves is the equivalent of a string of insurance premiums. Protection from the evils associated with a shortage of generation is the payoff of the insurance program.

When a utility is interconnected with other utilities, the nature of reserves is different. For an interconnected utility under current conditions, a reserve program can be considered to be part of the tax structure. The cost of owning the reserves remains the equivalent of a stream of payments. However, the payments should be thought of as a tax liability instead of an insurance premium. The benefit of the tax payment is increased reliability for the entire network, not just for the owner of the reserve. The benefit is thus a public good, an improvement in the reliability for all loads connected to the grid.

The push to make the electric industry more competitive has ignored the structure of the reserves required by NERC’s regional councils. Reserve programs have retained their historic nature as tax burdens. As tax burdens, reserves provide a direct benefit to the utility only in the form of a “Get out of jail free” card. Reserves thus provide the utility an exemption from any regional penalty imposed for not having the reserve. The real benefit of the reserves is spread over the entire grid.

The structure of the reserve requirement as a tax has created market power in some areas of the country during the market restructuring process. The California ISO experienced some problems during 1999 and 2000 with high prices for the reserve market. New South Wales in Australia, under different reserve requirement rules, experienced similar price spikes in October and November 2001. Similarly, PJM experienced a run up in the price for its ICAP reserve market. Purchasers in the ICAP market occasionally paid very high prices. These high prices were the equivalent of the penalty that was to be imposed for the not meeting the ICAP reserve requirement. Purchasers were thus faced with a monopoly taxing program.

On May 7, FERC released three memos written by Enron's outside counsel that explained strategies used by Enron to profit from the structure of the California electricity market. The "Get Shorty" strategy involved selling ancillary services in the day-ahead market and then canceling the commitment in the "real-time market." Reserves are one form of ancillary services traded by the California ISO. The Enron memos also alluded to the inability of Enron to influence the ex-post price used to cash out the physical market.

Structuring an Insurance Program

If the industry is to continue its move toward a competitive market, the structure of reserve programs should be changed to reflect the concept of casualty or medical insurance. The structure of the reserve programs must move away from the form of mandatory taxes. Insurance policies state the premium to be paid by the policyholder, the benefits to be paid to the policyholder, and the circumstances under which the payment is to be made. Most reserve programs do not define any benefits to be paid to the policyholder except for exemption from penalties for not having reserves.

Because of the large number of reserve programs that have been developed by the NERC regional councils, this paper will only deal with the generic concept of modifying a reserve requirement to make it look like an insurance policy instead of a tax structure. This paper discusses the reserve program generically classified as spinning reserve.

Spinning reserve improves the ability of the network to respond to sudden outages. As is implicit in its name, a spinning reserve program generally requires its provider to have unused available capacity on a spinning generator. The spinning reserve generally must be able to provide the specified increment of electricity during the five or ten minutes following an initiating event, such as the loss of a generating unit on the network. This timing requirement reflects the inertia inherent in many generating systems, the inability to change production levels rapidly.

Some reserve agreements allow a utility to meet its spinning reserve requirement with fast start generators, such as combustion turbines, diesels, or hydroelectric generators. Occasionally reserve agreements will also allow the utility to meet its spinning reserve requirement through automated load control programs. Finally, some reserve requirements can be met through the purchase of reserves from a neighboring utility. The PJM ICAP program is an example of the ability to buy and sell reserves.

An insurance program involving spinning reserve should begin with a good definition of an initiating event. Spinning reserves are necessary for times when a generator is suddenly forced out of service. Accordingly, the sudden shut down of a generator can be identified as an initiating event. Spinning reserves may also be called upon when the system is short of power in general. System controllers could issue a call for spinning reserves to be released so more power is generated on the system. Different reliability regions may devise different mechanisms for identifying an initiating event for the use of spinning reserve.

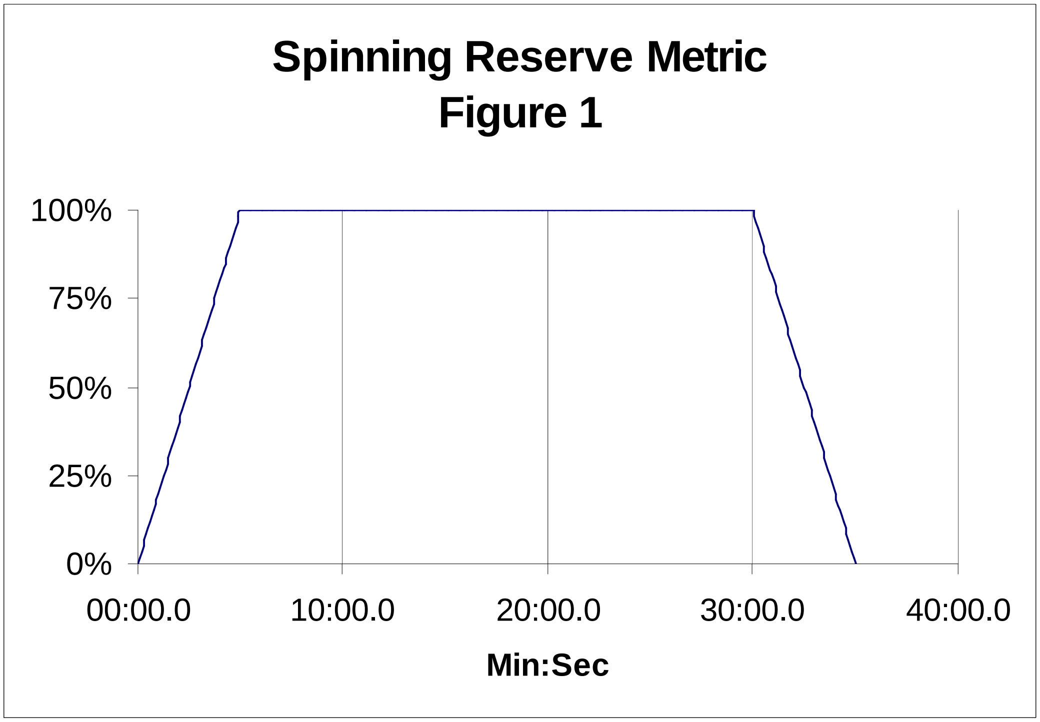

Figure 1: The typical generation pattern that might be expected in response to a call for spinning reserves to produce electricity.

An insurance program involving spinning reserve should also have a metric for the benefits associated with the insurance payment. Figure 1 provides a sample metric for spinning reserves. When the initiating event occurs, the insured utility could be entitled to electricity in the amount illustrated. Over the first five minutes, the entitlement increases linearly from 0% to 100% of the reserved amount. For the next twenty-five minutes, the entitlement stays at 100%. Finally, over the next five minutes, the entitlement decreases linearly from 100% to 0%. The trapezoidal shape and duration of the entitlement in Figure 1 results in an energy entitlement equivalent to a half hour times the reserved amount. A 100 MW reserve entitlement would have 50 MWH associated with it.

The entitlement reduces the amount of electricity that the insured utility would have to buy on the physical market. The entitlement would change the schedule of electricity that the insured has with other utilities in the network. At the same time the entitlement would affect the other utilities in the spinning reserve sharing group. They would be required to provide electricity in total that is equal to this metric.

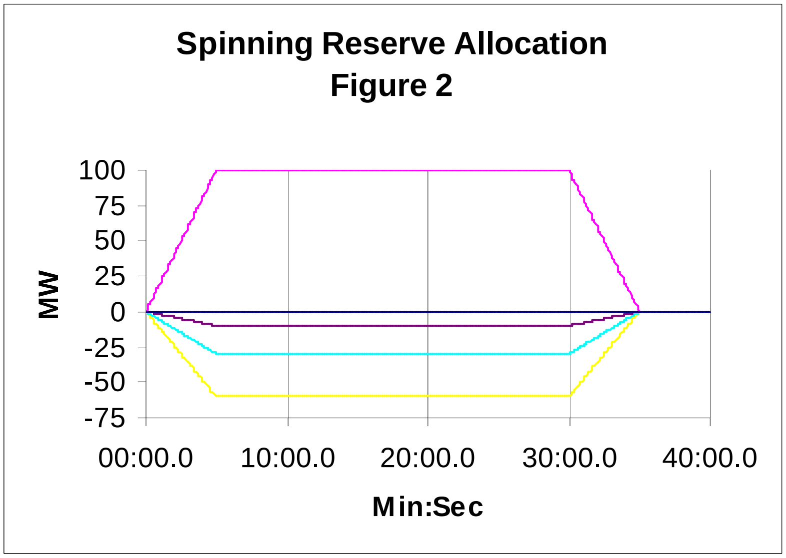

Figure 2: The power entitlement (positive values) and the power obligations (negative values) associated with an initiating event of 100 MW.

Figure 2 converts the spinning reserve entitlement metric into power based on an assumption that the initiating event was the loss of a 100 MW generating unit. The utility was thus be entitled to receive up to 100 MW and a total of 50 MWH during the thirty-five minutes after the initiating event. The metrics below the horizontal axis represent the obligations of the pool members to provide electricity. The assumption is that there are three utilities that make up 10%, 30%, and 60% of the pool. The metrics of their obligations are based on these percentages of the 100 MW entitlement of the insured utility.

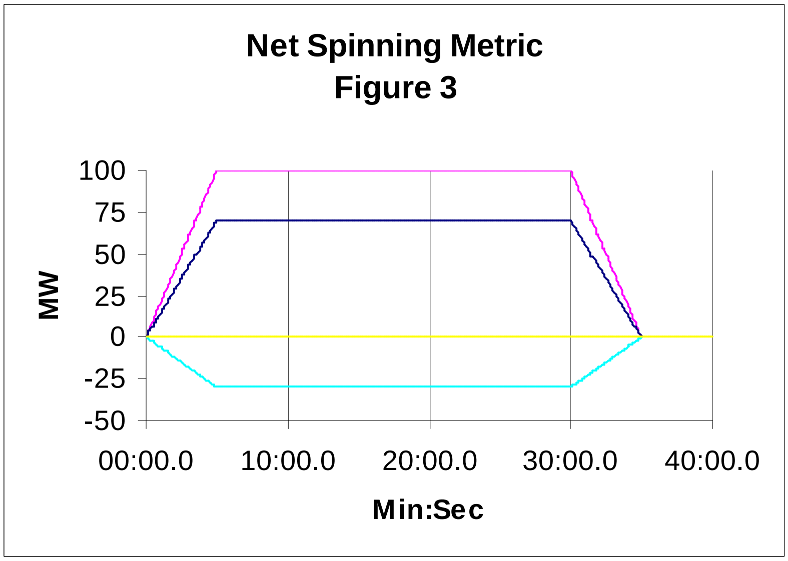

Figure 3: The gross power entitlement (top line), the power obligation (bottom line), and the net power entitlement (middle line) for a spinning reserve participant who constitutes 30% of the pool and who experiences a 100 MW initiating event.

Figure 3 is the net result for the insured utility in the situation where the insured utility makes up 30% of the pool. The insured utility is entitled to 100 MW, which is 100% of its loss. The insured utility is at the same time obligated to provide 30 MW, because it makes up 30% of the pool. As a result, the insured utility is entitled on a net basis to receive 70 MW, which is the difference between its 100 MW entitlement and its 30 MW obligation.

Self Insurance

Some market participants believe that their generators operate more reliably than the generators of other market participants. Such market participants may not want to participate in a traditional mutual insurance pool. They see that their higher reliability will result in them supporting the insurance pool. After all, all participants in the insurance pool provide a proportionate share of the metric during any event and receive the metric based on their proportionate share of the outages.

The desire for a self-insurance option can be illustrated under the assumption of having two equal sized participants in the pool, each with generic 100 MW units. Any outage will result in a metric for 50 MWH using the metric described previously. Because the two participants are of equal size and thus are each 50% of the pool, an outage will result in the transfer of 25 MWH to the market participant whose generator was forced out of service. With unequal reliability rates, the market participant with more forced outages will receive greater benefits.

The utility with the higher outage rate normally would have a greater reserve requirement. Certainly if the two utilities were not interconnected, the utility with the higher outage rate would need more installed generation to provide the same level of reliability to its customers. When the two utilities are interconnected, the utility with the higher outage rate would put demands on the interconnection more often, being a tie-riding freeloader.

The value of the energy received under an insurance program for spinning reserves will depend on the mechanism used to cash out physical deliveries of electricity. Some markets have developed ex-ante pricing mechanisms that nominally clear the market before the electricity is delivered. These ex-ante prices are often not appropriate for unscheduled physical deliveries because they do not reflect the actual imbalance in the physical market.

Figure 4 presents WOLF (Wide Open Load Following) pricing, a mechanism that adjusts nominal prices for physical market imbalances.[3] Figure 4 begins with a supply and demand curve when the physical market is out of balance. The nominal price in Figure 4 represents an ex-ante price, such as one that might have been determined through a generic bidding process. The nominal price crosses the supply curve and the demand curve at points that represent different physical quantities. The difference between these physical quantities is known as Area Control Error (ACE).

ACE has long been used by electric utilities as a signal to increase or decrease generation in the utilities control area. In most of the United States and Canada, ACE is calculated every 2-4 seconds. If the network is balanced, ACE is equal to zero. When ACE is equal to zero the nominal price is at an economic level where the supply is equal to demand. This economic level where supply is equal to demand is the equilibrium price, the goal of many economists.

---

[3] For greater information on WOLF pricing see "WOLF Pricing," *Public Utilities Fortnightly*, 1994 October 1 and "Profit-Enhancing Seam Management: A White Paper on Pricing The Unscheduled Flows of Electricity Across the Seams Between Utilities Using A Geographically Differentiated Auction of Inadvertent Interchange", www.LivelyUtility.com, 2001 March 25.

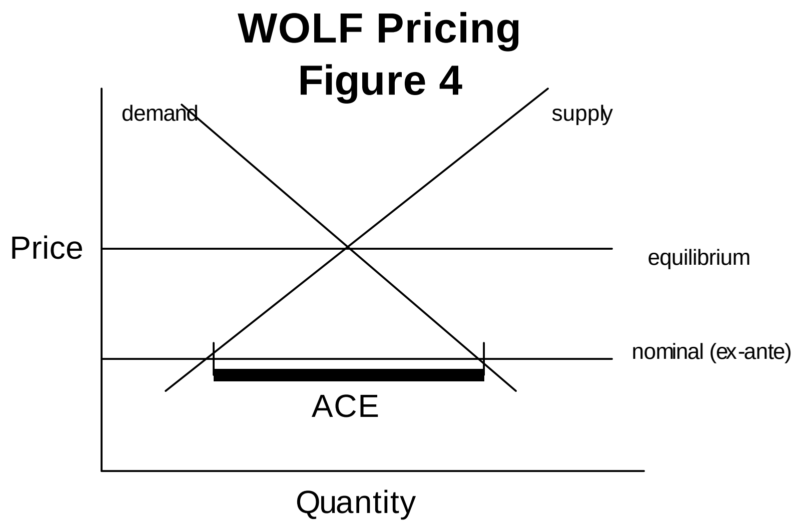

Figure 4: The economic theory behind WOLF (Wide Open Load Following) pricing. When ACE (Area Control Error) is negative due to demand being in excess of (to the right of) supply as shown in the diagram, the Ex-Ante nominal price is below the equilibrium price and the price for unscheduled flows of electricity should be above the Ex-Ante nominal price.

For many years, operators controlled their systems to achieve a zero ACE crossing at least every ten minutes. As is implied by the phrase zero crossing, ACE is not held at zero. ACE goes positive (defined as supply being in excess of demand) and negative. The economic implication is that the ex-ante price varies from the equilibrium price whenever ACE is non-zero. The greater the magnitude of ACE, the more the ex-ante price varies from the equilibrium price.

The unanticipated outage of a generating unit will change ACE. The change in ACE will change the equilibrium price pursuant to the concepts presented in Figure 4, generally increasing the equilibrium price. The actual change in the equilibrium price is the result of a shift in the supply curve to the left. The shift of the supply curve to the left is the result of removing the affected generator from the mix of generators supplying electricity.

After the initiating event, many generators on the network will respond by increasing their output. This change in generation will not be limited to generators owned by the affected utility, nor even to generators in the same reliability region. All systems will notice a decline in system frequency. When appropriate due to frequency being substandard, these utility systems will increase their generation.

Cashing out the Physical Market

FERC has initiated a rulemaking (RM01-12-000) to develop a standard market design (SMD). FERC staff prepared and released discussion papers supporting an ex-ante bid based market as the SMD. On 2002 April 9 and 10, I filed initial comments saying that the SMD should be a cash out of unscheduled flows of electricity, such as would be supported by the WOLF pricing mechanism discussed very briefly above. The unscheduled flows that should be of interest in the SMD process are across the financial seams where ownership of wires and of electricity changes. Thus, SMD should be concerned with financial management of the seams. The financial management of the seams will indirectly impact the physical management of the seams.

Figure 5 presents two possible sets of prices that result when an initiating event causes spinning reserves to be operated. Both sets of prices begin and end at $20/MWH. One set of prices soars to $2,020/MWH. This higher set of prices might be appropriate when the network is short of generation or when some participants in the spinning reserve program do not respond to the call for the operation of spinning reserves. The other set of prices climbs only as far as $30/MWH. This lower set of prices might be appropriate when the network has a significant surplus of generation, such as in the middle of the night.

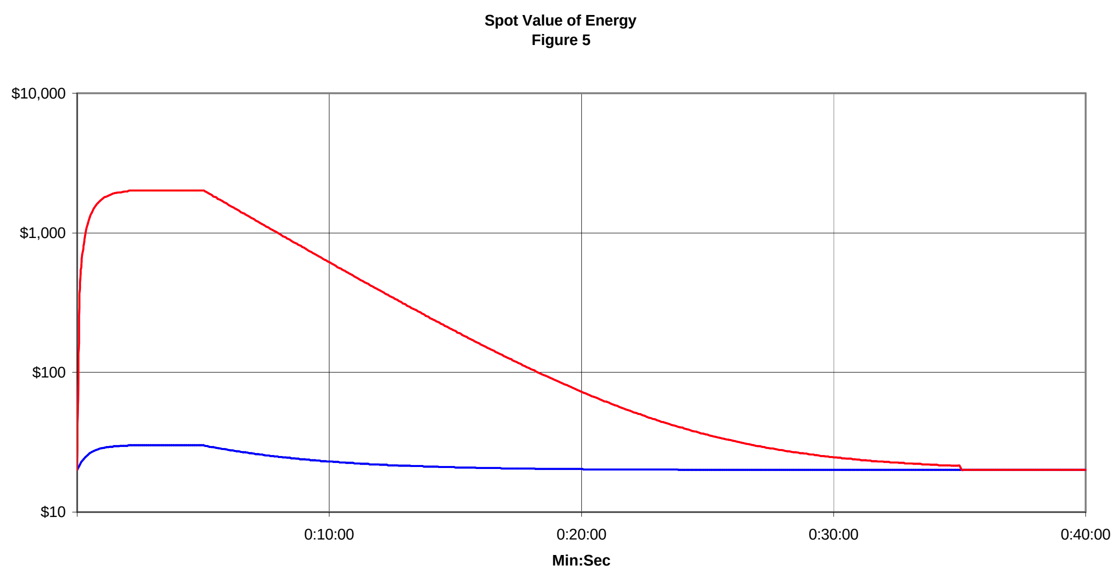

Figure 5: Hypothetical prices for unscheduled flows of electricity during a call on spinning reserves. Prices change every 5 seconds, slightly less often than utilities normally measure their inadvertent interchange with each other. Some utilities measure inadvertent interchange much more frequently than every 2-3 seconds.

The prices in Figure 5 provide a way to evaluate the standard metric presented in Figure 1, as that standard metric develops the delivery obligations and receipt entitlements shown in Figures 2 and 3. This evaluation is summarized in Table 1. The payments are for electricity delivered to meet a standard 100 MW metric obligation, which was represented as the top lines in Figures 2 and 3. The basic energy value is the $20/MWH assumed beginning value of electricity before the initiating event. The unit value is the reliability value divided by the 50 MWH of energy associated with standard metric for 100 MW.

Value of Standard Metric For 100 MW
Table 1

	Low Value	High Value
Payment	$1,108.93	$22,786.56
Basic Energy Value	$1,000.00	$ 1,000.00
Reliability Value	$ 108.93	$21,786.56
Unit Value	$2.18/MWH	$435.73/MWH

Table 1 shows two widely differing values for the energy associated with a standard spinning reserve response metric. The difference between the values is the result of differing conditions at the time of the event initiating the call for spinning reserves to be released. Similarly, the payments made by health or accident insurance policies will greatly be influenced by the nature and timing of the initiating events. The potential for such a high unit value of spinning reserve response would lead some participants to self-insure. The high unit value of spinning reserve would lead others to respond even when they are not technically part of the reserve sharing pool.

The high unit value of energy during calls for the release of spinning reserves emphasizes the need to have prices be relevant for short periods of time. The graphs in Figure 5 and the analysis in Table 1 are based on 15 second pricing periods. Table 2 presents the same data using 5 minute pricing periods for the entire hour after the initiating event.

WOLF Payments for Selected Time Periods After an Initiating Event
Using a Simple Average of Reliability Value
Table 2

	Low Value	High Value
1st Five Minutes	$9.10/MWH	$1,819.57/MWH
2nd Five Minutes	$5.74/MWH	$1,147.33/MWH
3rd Five Minutes	$1.71/MWH	$341.39/MWH
4th Five Minutes	$0.51/MWH	$101.58/MWH
5th Five Minutes	$0.15/MWH	$30.23/MWH
6th Five Minutes	$0.04/MWH	$8.99/MWH
7th Five Minutes	$0.01/MWH	$2.68/MWH

8th Five Minutes	$0.00/MWH	$0.00/MWH
9th Five Minutes	$0.00/MWH	$0.00/MWH
10th Five Minutes	$0.00/MWH	$0.00/MWH
11th Five Minutes	$0.00/MWH	$0.00/MWH
12th Five Minutes	$0.00/MWH	$0.00/MWH
1st Forty Minutes	$2.16/MWH	$431.47/MWH
1st Hour	$1.44//MWH	$287.65/MWH

Some electronic devices can respond faster than the ramp rate indicated by the standard metric of Figure 1. Thus, some devices might be able to earn the $1,819.57/MWH by providing a block response during the first five minutes. The price would also be applicable to any other unscheduled flows of electricity, such as uninstructed generation or load with no contracted supply.

I note that the average of the reliability value over the entire 40-minute response period would provide a distorted incentive for fast response an initiating event. The hourly price signal currently used by PJM would provide an incentive for generation even during the last half of the hour when the initiating event was no longer a concern.

Conclusions

There is increasing emphasis on having a market solution to electric power. The reserves portion of the electric industry has not yet been restructured to reflect a market solution. The reserve portion of the electric industry remains a procrustean taxing mechanism. The public good provided by the reserve requirement is antithetical to the concept of a competitive market. Indeed, the concept of a public good is socialistic.

The reserve portion of the electric industry can be converted from a taxing mechanism to an insurance mechanism. An insurance mechanism is more consistent with the concept of a market solution. Such an insurance mechanism requires a good definition of the initiating event that invokes the support associated with the reserve requirement. The insurance mechanism similarly requires a good metric for the support associated with participating in the reserve market.

Converting the industry's view of reserve into program compatible with an insurance program will reduce market power and reduce the number of strategies market participants have had to game the system. Further, few participants in the electricity market are now able or willing to make the commitment to provide reserves. However, many participants are willing to participate in the physical market. Indeed, many consumers who buy and schedule power would be able to participate in the physical market by curtailing consumption during periods when the reliability of the network is being stressed, as when ACE is hugely negative.

The establishment of an insurance mechanism for the reserve requirement needs also to have a physical cash market, such as created by WOLF. The physical cash market can be used for those network participants who do wish to self-insure. The physical cash market can also be used for any physical imbalance a marketer might incur, whether it is a shortage or a surplus. Further, the physical cash market should be for small time intervals in order to provide sufficient incentives for participants to help the network keep the lights on.

Mark B. Lively is a consulting engineer in Gaithersburg, Maryland, with his practice limited to utility economics. He has degrees in Electrical Engineering and Industrial Management from the Massachusetts Institute of Technology and its Sloan School of Management. Mr. Lively developed the Committed Unit Basis (CUB) approach to evaluating long-term contracts between utilities and Qualifying Facilities. The adoption of CUB by the Texas Public Utilities Commission in 1984 significantly reduced the tension between Texas based cogenerators and utilities.