

## Resource Adequacy and Capacity Schemes

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When energy markets are restructured to allow for competition, regulated rates are replaced by more volatile prices of the open market. In this environment, the expectation of lower prices can cause private investors to postpone expenditures on new generation capacity or the expansion of transmission network. Both are desired by system operators for maintaining grid reliability. The lack of surplus capacity or congestion in the system can further increase price volatility. The price-destabilizing effects associated with temperature extremes, unplanned outages, the dominance of generation by a single fuel and so on are exacerbated when coupled with insufficient system capacity. As a result, regulators focus on resource adequacy.

In competitive markets, investors have to recover their costs through market prices not through COS regulation. In this environment, there are basically two options to ensure resource adequacy:

1. An energy-only market.
2. Reserve requirement based approaches:
  - a. An energy market + a capacity requirement (which is almost equivalent to an energy-only market if penalties are high enough).
  - b. An energy market + a capacity market (may also involve a capacity requirement).
  - c. An energy market + a capacity payment.

The table below summarizes different approaches to promoting investment.

<b>Approaches to promoting investment in system expansion</b>			
	<b>Capacity Payments</b>	<b>Capacity Markets</b>	<b>Alternative Approach</b>
Argentina	Used to be fixed	In 2000, capacity markets	
Australia	No	No	Obligations to ensure supply (Victoria)
Chile	Yes	No	
Colombia	Yes	No	
Norway	No	No	Direct ownership of some peaking plants
New Zealand	No	No	Completely free market
Spain	Fixed	Bilateral contracts	
Sweden	No	No	Direct ownership of some peaking plants
UK	LOLP method until Oct 2000	No	Since Oct 2000, no more separate payments
US		Some (PJM, NEPOOL)	Obligations to ensure supply (NYPP)

*Source: Regulated Capacity Payments, IEA Working Paper, June 1999 and various internet sites.*

In energy-only markets, on-peak energy prices may be quite high and must be allowed to rise to send the right signals. For example, if loss of load probability (LOLP) is 1 day in 10 years (e.g., the PJM market), prices in the range of \$12,000-\$30,000/MWh are needed. But, average price will likely be lower. Less capacity will be available than under a system with reserve requirements. Peak energy consumption would be lower due to demand-side response. Energy-only markets work in both Australia and New Zealand, with maximum prices between \$2,500 and \$5,000.

PJM, on the other hand, has a bid-based, day-ahead installed capacity (ICAP) market with associated capacity obligations for load-serving entities (LSEs). The market-clearing price is the lowest matched sell offer. But, LSEs can also trade ICAP among themselves after the ICAP market results are announced at noon. An LSE is required to buy ICAP in order to serve load. There are several flaws and PJM authorities themselves recognize these as follows:

- There is high market concentration in capacity ownership.
- Most ICAP is held by LSEs who may intentionally make credits expensive or unavailable by delisting to deter entry.
- External ICAP resources are not allowed.
- ICAP market is illiquid, which is worsened by overrating of need by current owners.
- Consumers pay for capacity reserves associated with future load growth of others.
- ICAP requirements are not adjusted to seasonal variations.
- The cost of ICAP inflates end-user price but response is unlikely given current metering and rate structure.

Market manipulation based on this flawed system is blamed for causing some price spikes starting mid-2000. First, in June 1, 2000, the daily price jumped to \$350/MW-day and remained around \$177/MW-day (the cap) for the rest of June while there was more than 900 MW excess capacity and the mild weather kept the energy price low. Then in early 2001, ICAP prices reached the \$177/MW-day cap after being as low as \$3.74/MW-day in Nov/Dec 2000 again apparently without real shortage. Deliberate delisting of capacity by some market players is blamed for these high prices.

Market Monitoring Unit of PJM seems to accept the fact that the ICAP market is not competitive. Some of the potential changes developed internally by PJM include the following.

- Allowing external resources.
- Changing month-ahead and day-ahead markets to price-taker auction, while retaining mandatory participation in the day-ahead market.
- Developing a new methodology for peak load obligation.

Even with the changes, PJM continued to have a market where price signals fail to reflect true cost of shortages.

NEPOOL has an ICAP (installed capability) market similar to that in PJM, but it is only monthly. Nevertheless, NEPOOL had similar market gaming problems since early 2000. With the suspicion of intentional withholding of capacity from the market to raise the market-clearing price, ISO New England filed with the FERC for elimination of the NEPOOL ICAP market. The alternative structure of price caps was not looked upon kindly by the FERC. Currently, the ISO is looking for developing long-term forward or option markets for energy and/or reserves. NEPOOL Participants Committee approved the elimination of ICAP

arrangements by the end of 2001. FERC appears to favor the forward reserves market idea but is not likely to approve the elimination of ICAP before a market-based alternative is fully developed.

The UK market was one of the first that used an LOLP (loss of load probability) based formula to calculate a capacity payment to generators for making capacity available to the system. Initially, these payments were based on the following formulas:

$$\text{Capacity payment} = \text{LOLP} \times (\text{value of lost load} - \text{system marginal price})$$

$$\text{Pool purchase price} = \text{system marginal price} + \text{capacity payment}$$

Consequently, the two dominant generators in the UK were able to manipulate the market and drive up both system marginal price and capacity payments up by announcing plant unavailability at times of peak demand and by gradually lowering their generation capacities. Although there were additions to capacity from IPPs and others, the net effect observed was a decline in capacity. Almost all other generation was from base load plants or IPPs with take-or-pay fuel contracts and day-ahead demand forecasts of the ISO were known. As a result, the two companies were able to forecast residual demand they would need to meet and restrain supplies accordingly to raise both the price and capacity payments. In response, regulators revised the pool system. According to new arrangements, starting October 2000, there is no longer a separate capacity payment.

Similar to the initial structure in the UK, the power purchase price in Argentina has spot and capacity components. The spot price, like the system marginal price in the UK, is determined at the pool. However, the capacity payment is fixed at \$10/MWh (\$5 for base capacity and \$5 for reliability) by the Secretaría de Energía and is only paid during peak demand blocks (6 am – 11 pm during workdays). One payment is made to thermal generators irrespective of whether a generator is dispatched or not (Potencia Base en Reserva – PBAS). Another, (larger) payment is made only if the generator is actually dispatched (Potencia Puesta a Disposición – PPAD). The result is that thermal generators have a short term incentive to reduce their declared bid price to ensure that they are dispatched, on the assumption that any resulting reduction in their energy payments will be more than compensated through higher capacity payments. This approach raises major concerns regarding:

- The economic efficiency of the system. Such bidding practices inevitably distort merit order dispatch and hence reduce the benefits of an electricity pool.
- The longer term sustainability of thermal generators. If the mechanism results in reduced income to thermal generators overall, then it is possible that system reliability will be threatened in the future.
- The long term costs of the electricity system. The plant mix that may result for the Argentine system will not be the most efficient, with consumers facing higher prices in the future.

In late 1999, the Secretaría de Energía approved new regulations that will cause the separation of capacity payments from energy payments. PPAD is replaced by Reserva de Mediano Plazo, which is independent of real dispatch, hydrology and bids, thus allows a fixed monthly income. PBAS is replaced with Reserva Contingente, which is paid to those units supplying the demand during dry hydrology periods. Units submit bids for providing this type of reserve but the price is limited at \$10/MWh. There are also new short-term capacity contracts.

Also, in other countries, capacity payments led to construction of inefficient peaking units, or, conversely, eliminated the incentive for availability during a crisis; and have been used to promote one fuel over others.

### ***So, where do we go from here?***

All the evidence indicates that capacity payments or markets, for the most part, do not send the correct price signals and, worse, they lead to inefficiency and/or gaming. Energy-only market is probably the most efficient solution for attracting the needed infrastructure investment. It will allow market participants to decide the best investment to sustain reliability, which could be new generation, or new transmission or even load response. But it is tough to implement. Because the price spikes (i.e., volatility), that are necessary to justify investment, and associated boom-bust cycles are not politically acceptable. Many energy companies do not like extreme volatility either. And, without real time demand side response, which may also be politically difficult to implement, an energy-only market would not work anyways.

Capacity requirements, on the other hand, are most consistent with the old integrated resource planning (IRP) approach (i.e., stability), but some of the old problems arise. For example, what is the right capacity margin? It used to be around 20% or more in 1990; it is about 12% now and varies across regions. It depends on generation stock, fuel prices, load shapes, demand elasticities of different customer groups, all of which are difficult to estimate. Another issue is the cost of keeping excess capacity and its allocation among the market participants. As we discussed, both capacity markets and payments have serious drawbacks. Both are prone to manipulation. ICAP markets can potentially be fixed but capacity payments are quite inefficient.

Having realized that the \$1,000 price cap and other market power mitigation efforts suppress scarcity prices, FERC's Standard Market Design called for "resource adequacy requirement," leaving almost all of the issues discussed above unanswered.

Perhaps, some of the companies who already trade options for peak power have the right idea. With a call option for energy, generators (sellers of the option) receive a capacity payment as an option premium and guarantee availability at the strike price. LSEs (buyers of the option) pay the market-determined option premium. The buyer exercises the option if the spot price is larger than the strike price and receives a payoff that is equal to the difference between the two prices. The value of the option will of course will be restricted by the price caps if they exist.

As regulators move forward with the fine-tuning of competitive markets, they need to remember that electricity markets are restructured to eliminate inefficiencies of COS regulation and IRP. If they re-establish rigid rules for resource adequacies or employ generous payment schemes that would encourage inefficient plants or keep building transmission lines with costs socialized to solve all congestion problems, this would defeat the purpose of restructuring.

*Last updated in July 2002*