Capacity Markets: A Bridge to Recovery?

A review of the ongoing evolution of market design.

BY CRAIG HART

LICAP, ICAP, UCAP, NoCAP. Some markets have them, some don't. Where they do exist, no two are equal.

California was built without one, as were the markets of Australia and New Zealand. Northeastern U.S. markets all have them, albeit in slightly different variations. MISO will start one of the biggest energy markets in the world without one. PJM, long considered the model market, is debating a major overhaul to its current scheme. Others are considering such changes as well.

As the experimentation with wholesale energy market deregulation continues, an evolutionary trend in capacity market design is becoming apparent in the United States. Most critics now support the conclusion that energy only schemes in price-capped markets do not provide sufficient revenues to induce new generation and keep system-critical, high-cost generation resources in the market. As such, it is likely only a matter of time before energy only markets are extinct.

But, while it appears that capacity markets are here to stay, there is little consensus regarding the best design. Markets in the United States are in a state of flux, with debate raging over many different capacity market pricing schemes. The pool-wide, single-price capacity market model utilized by PJM and others now appears too simplistic. New designs are calling for ever-more complicated structures aimed at fine-tuning the location, the timing, and the type of generation resources that capacity markets induce.

While the winning recipe has yet to be selected, it is likely that participants in certain markets will witness significant changes. In certain load pockets, generators could see a meaningful increase in gross margins if a pricing scheme that compensates generators based on location is adopted. Flexible units may receive an additional bump if changes being considered in PJM are adopted. But, these shifts are likely only to persist in the short to medium term. While providing a much needed bridge to market recovery for some, if the markets function properly, price differentials should dissipate over time and bring long-term pricing back to the mean.

Background

Capacity markets are designed to ensure resource adequacy. While various definitions exist, resource adequacy generally refers to the sufficiency of generation resources to meet the peak energy needs and maintain the stability of an electric system.

In a traditional, regulated utility world, generation plants are added after resource planners determine the amount of new capacity that will be needed over the coming years to meet demand. While they are determining the actual amount of total installed capacity necessary to ensure resource adequacy, resource planners also attempt to optimize the type of capacity that is built in terms of fuel type, technology, and market segment (*i.e.,* baseload, intermediate and peaking). In this way, the best generation mix necessary to meet peak demand is determined through a central planning process.

In a deregulated world, the decision to build new capacity is made by individual market participants instead of through a central planning process. The underlying question becomes how to design a market to properly incentivize profit-maximizing participants to develop enough generation capacity to ensure resource adequacy. As the theory goes, the answer is that the market must provide adequate compensation so that a new entrant is able to earn revenues that are high enough to cover costs and earn a fair return.

Two Basic Models

There are essentially two schools of thought when it comes to designing markets that provide adequate revenues to generators: energy only (referred to as "NoCAP") and energy-plus-capacity markets.[1]

Many have followed the NoCAP route. In the United States, California, ERCOT, and MISO started without an explicit capacity market. Australia and New Zealand, as well as the markets in Ontario, Alberta and Scandinavia (NORDPOOL) all have functioned without a formal capacity support mechanism. The general belief (hope) in these NoCAP markets is that sufficient revenues will be earned from the energy markets (plus other ancillary services where applicable) alone to induce an adequate amount of new generation resources. The idea is that the inherent volatility of the energy markets will deliver enough high-priced hours during summer- or winter-peaking periods that a new generator would be fully compensated and earn a fair return. The logic for marginal, system-critical resources is the same: The few high-priced hours when these units are dispatched will provide enough compensation to cover going-forward costs and keep the units from retiring.

The other option, of course, is to couple a capacity market with the energy market. PJM, ISO New England, the New York ISO (NY-ISO), and others have used variants of this theme fairly successfully. Energy-plus-capacity markets generally function by compensating generators based on total installed, or available, capacity.[2] Generators receive a payment that supplements revenues earned in the other markets. The idea is that total revenues should be sufficient to cover going-forward costs at a level that is comparable to what generators earn from hourly dispatch in an energy-only market.

Bumps in the Road

As deregulated markets collect a historical record that includes the experience of a full boom-bust business cycle, several shortcomings in existing markets are becoming apparent. For NoCAP markets, it is the institution of price caps that is arguably the most notable contributor to their inability to provide a stable and sufficient revenue stream to generators. Others with capacity markets in place are finding that simply adding generic capacity resources somewhere within the market footprint may not be the optimal path to ensuring resource adequacy. What started as simply a question of how much, has recently matured to a question of what, where, and when.

Price Caps. In U.S. energy markets, extreme price volatility is unpalatable to the general public. As a reaction to high prices in the Midwest in 1998, PJM in 1999, and California in 2000, many markets created price ceilings (or price caps) to protect the public from extreme energy price volatility. But the problem with this type of protection is that it sacrifices the prospect of long-term market stability for the sake of avoiding a damaging summer newspaper headline.

This is especially true in NoCAP markets. Marginal generators in NoCAP markets are dependent on the few days when the intrinsically volatile energy markets deliver high-priced hours. The ability to capture revenues during these high-priced times gives marginal generators the ability to capture a sufficient level of revenues. But, with price caps in place, generators lose this revenue which tends to dampen the new build signal and undermine the ability of system-critical resources to capture adequate revenues.

Location. Many have begun to recognize that the regional diversity of the geographic footprint covered by power pools is such that they need to worry about where generators are encouraged to build. Given the constraints of the transmission system, it is critical that new generation be located as close to load as possible. For example, building new generation in western Massachusetts does not solve the supply situation in southwestern Connecticut.

In single-price capacity markets, there is no incentive or price signal provided by the capacity market that encourages new generation to build in an area that benefits the grid. Differences in locational marginal pricing (LMP) encourage generators to build closer to higher-priced locations, but this does not provide enough benefit to marginal generators.

The shortcoming of non-locationally based capacity markets can be witnessed in part by the need for many markets to continue to maintain reliability must run (RMR) programs. RMR payments are designed to compensate system-critical resources that are needed to maintain system reliability. These resources are often older units that run infrequently due to inefficient, out-moded equipment with high heat rates. In many cases, these units would not cover their going-forward costs and would be retired if they didn't receive additional monetary support from RMR payments.

For example, units like El Segundo on the beach in Los Angeles or Devon on the coast of Connecticut are needed to maintain system reliability. In those areas it is very difficult to site new transmission lines, and probably impossible to site a new power plant anywhere near El Segundo, so the system needs to ensure that these units earn sufficient revenues to keep them from retiring. Without a capacity market that provides additional compensation for these generators (or more modern substitutes), the power pool must continue to prop them up with administrative RMR payments.

Operating (and Fuel) Diversity. In addition to issues surrounding location, questions have been raised about the ability of capacity markets to address the operating profile of new equipment. The argument is that even if you get enough capacity at the right place, you still need to worry about the type of equipment that is built. The system needs resources that have operating flexibility and also contribute to the fuel diversity of the overall fleet.

The "dash-for-gas" witnessed in the recent past created a glut of homogenous units. One problem that has surfaced as a result of this monolithic block of capacity is that supply is very dependent on gas prices. Given the correlation of gas prices to heating needs in winter, regions have seen shortages and price spikes when gas-fired generators sold gas into the heating market rather then generating electricity. In addition, many of the units have similar operating characteristics. Many believe that capacity markets need to have the ability to recognize fuel and operating diversity to avoid dependency on one fuel type and to maintain a fleet of resources that is capable of meeting all of the needs of the system operator in terms of ability to start quickly and follow load.

Demand Curve. Finally, there has been one other major shortcoming observed in capacity market design that occurs on the demand side of the equation, as opposed to the supply side issues like those already discussed. Most markets have utilized what is referred to as a "vertical demand curve" to date. This term refers to the construction of most markets where demand is set equal to the target reserve margin which, in effect, creates a fixed quantity that is completely price insensitive.

While a description of the full dynamic of the pricing structures of demand curves are beyond the scope of this article, the vertical demand curve typically has created very volatile pricing. Historical pricing patterns in existing capacity markets have tended to be shaped by boom/bust or floor/ceiling behavior where prices hover near zero when the market is oversupplied and jump to the capped price or deficiency level when the market passes through equilibrium and enters a period of shortage. This binary pricing pattern produces unwanted volatility that reduces the predictability of revenues for suppliers. Reduced predictability undermines new entrant planning or forces builders to raise costs by including a premium to cover this price risk.

Capacity Market Evolution

In response to these perceived shortcomings, many markets are considering, or already are undergoing, massive overhauls. Some are adding capacity markets for the first time, while others are adding new features to existing markets. These overhauls are spurring a new round of thinking on capacity market design that appears to be leading to interesting—and increasingly complex—new designs. While the final direction of the markets remains to be seen, what is becoming apparent is a natural evolution in capacity market form and function.

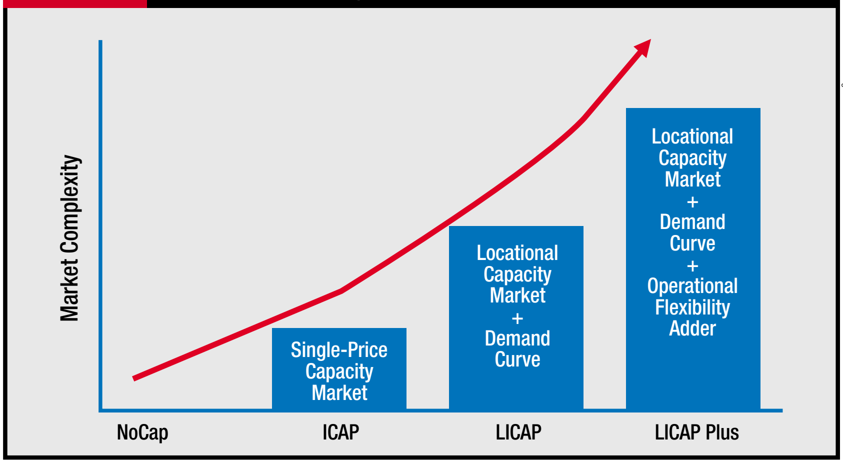
The bottom of the evolutionary ladder (*see Figure 1*) can be defined as beginning with NoCAP markets as seen in California and ERCOT. Given the issues associated with price caps in most markets, this structure appears to be insufficient. From there we move up the evolutionary scale to simple, pool-wide capacity markets like the current form of the PJM installed (ICAP), or unforced (UCAP), market. But, as discussed above, this relatively simple structure addresses the question of volume only.

The locational ICAP market (LICAP) structure that follows the relatively simplistic ICAP/UCAP model adds a locational component to the pricing structure to add criteria for determining where in the pool new resources are constructed. The proposed system in New England, as well as the current system in New York, are examples of this LICAP approach.

In addition to addressing location, the LICAP phase also has included modifications to the market-demand curve. By constructing what is referred to as a "sloped" or "curved" demand curve, market designers are attempting to fine-tune the timing of the new build signal and eliminate the binary pricing behavior observed in markets with vertical-demand curves. The sloped-demand curve attempts to add subtlety to the market signals by producing increasingly high levels of compensation for generators when the market moves towards scarcity levels, and by gradually decreasing levels of compensation when resources are adequate.

PJM now is considering taking this a step further, to what can be referred to as "LICAP Plus." If the original PJM structure simply addressed the issue of how much, and the New York/New England LICAP markets add functionality for addressing when and where, the new PJM design also will help determine what type. The scheme under discussion in PJM is designed to address the operational flexibility of the resources that are built. The proposal includes criteria to provide price distinction based on the ability of resources to follow load or provide quick-start functionality. This will help ensure that the generation mix as a whole is diverse enough to provide the full range of resources

FIGURE 1 CAPACITY MARKET EVOLUTION



Source: U.S. Power Generating Co.

needed to meet system needs.

So what does all this mean? In terms of market evolution, there is no reason to expect that all of these steps will be followed in order by all markets. As experience builds and historical examples accumulate, it is likely that markets will level-jump from NoCAP to LICAP, for instance, as is being considered in California (*see Table 1*). Certainly, if a LICAP Plus market appears to work, we may see markets open in the future with that structure used from the beginning. Regardless, the current state of the various markets in the United States provides a live example of the progression of thought on how best to ensure resource adequacy in deregulated markets.

TABLE 1 — CAPACITY MARKET DESIGNS IN U.S.

Market	Current Capacity Market	Future Capacity Market	Comment
CA	None (energy-only)	ICAP/LICAP	Market Design 2002 (MD02) includes an Available Capacity (ACAP) market that will function like ICAP/ UCAP markets. Also considering adding a LICAP component.
ERCOT	None (energy-only)	Under Discussion	Considering various capacity market options as part of overall market overhaul.
MISO	None (energy-only)	LICAP Plus	Under FERC order to design a resource adequacy scheme that is consistent with current (and future) PJM system. Started market April 1 without capacity market.
NY ISO	LICAP[1]	No Change	New York is a three-zone LICAP market with demand curve. Pricing zones for New York City, Long Island and Rest of State.
ISO NE	ICAP[1]	LICAP	Moving to a 5 zone LICAP market with demand curve. Will look a lot like New York.
PJM	ICAP[1]	LICAP Plus	In process of designing a new Reliability Pricing Model that will include price adders for location and operating flexibility. Also considering adding a demand curve.

1. Markets calculated based on unforced capacity availability which adjusts available capacity to reflect forced outages. Referred to as ICAP markets that utilize UCAP calculation methodology.

Source: U.S. Power Generating Co.

The outcome of the discussions under way in PJM will have a significant impact on the future form of capacity markets. PJM has been viewed for some time as a model market, so others likely will continue to follow its lead and adopt similar market structures. In addition, MISO is under order from the Federal Energy Regulatory Commission to produce a system that is consistent with PJM. Given these developments, within several years the Northeast likely will be dominated by LICAP markets, while LICAP Plus could stretch from the Mid-Atlantic to Montana. Developments in California and ERCOT should add additional momentum to the LICAP model in future years.

For market participants, these new structures could have material impacts, at least in the short term. For a generator in Connecticut, for example, the addition of LICAP could mean the difference between less than $1/kW-mo. in capacity compensation or $5 or $6/kW-mo. For a generic 600-MW combined-cycle plant, this could add $40 million per year in revenues. To put this in perspective, an additional $40 million would increase gross margins from 15 to 40 percent for this typical plant, which goes a long way toward covering debt service on struggling merchant plants.[3] For plants in other parts of NEPOOL, the shift will be less dramatic or perhaps even nonexistent. A plant in the proposed "Rest-of-Pool" zone will see little, if any, price appreciation.

While price shifts in tight locations like southwest Connecticut and eastern PJM may help struggling generators in the short term, they are unlikely to persist over the long term. There are essentially three outcomes for the revised markets, all of which should lead to prices that trend toward the mean. First, if the markets function as intended, high prices in load pockets will attract new resources that will alleviate the shortage and bring the zone back into equilibrium. This will serve to drive prices down in this region over a relatively short time horizon.

Another possibility is that new transmission capacity will be built that alleviates constraints within a zone and allows for more import capacity. This outcome also would put the same downward pressure on prices. In fact, some are calling already for NEMA/ SWCT zonal prices in New England to converge on Rest-of-Pool prices within one year of LICAP start because of planned transmission upgrades. Finally, if a new market structure leads to sustained high prices for merchant generators, it will be apparent that the market is not working as intended and regulators will be forced to reconsider the market structure due to the impact on consumers.

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Endnotes

1. This categorization excludes other ancillary services including spinning reserves, regulation, black-start capability, etc. Nevertheless, it is important to note that it is the combination of energy, ancillary services, and capacity products that provides a total revenue package to generators. But, since these other ancillary services do not differentiate the individual resource adequacy markets, a discussion of them is considered out of scope of this article.
2. Many markets account for scheduled outages in determining unit availability.
3. Final market designs may include mechanisms for subtracting infra-marginal revenues when determining capacity compensation. If this is ultimately adopted, assuming all else remains equal, the more a generator earns in the energy market the less it will earn in the capacity market.