An Assessment of the Financial Performance Obligation Proposal by the American Forest & Paper Association

Jonathan A. Lesser, Ph.D.

Guillermo Israilevich, Ph.D.

Bates White, LLC

Paper Presented at the
FERC Technical Conference on Capacity Markets

May 7, 2008

1. Introduction and summary[*]

In response to the Federal Energy Regulatory Commission's ("FERC" or "the Commission") June 22, 2007, Advance Notice of Proposed Rulemaking addressing potential reforms to organized wholesale electric markets,[1] the American Forest & Paper Association ("AF&PA") proposed a market design alternative called "Financial Performance Obligation" or "FPO."[2] The FPO proposal would apply to regional transmission organizations (RTOs) and independent system operators (ISOs) that either have implemented markets for installed capacity or are in the process of implementing them, such as the PJM, NYISO and ISO-NE markets.

While AF&PA should be commended for providing a proposal, as opposed to simply reciting complaints about capacity markets, its FPO proposal raises many questions regarding its implementation and its potential to deter new generation and demand response investments.

FERC, stakeholders, RTOs, and ISOs have all worked together to develop the systems in place to ensure adequate capacity today and plan for tomorrow's load growth. These capacity markets, while still requiring some refinements, have brought forth promising initial results by incenting a huge growth in demand response, reduced retirements of needed generators, led to the reactivation of mothballed facilities, reduced exports of local resources to neighboring markets, and encouraged development of new supply resources.[3] In their initial phases these capacity markets have succeeded in attracting new resources that would otherwise not have been available to meet the reliability needs of customers in these regions. Going forward, market participants will rely on these market mechanisms as they plan for

---

[*] This paper was prepared on behalf of the Electric Power Supply Association (EPSA).

[1] 119 FERC ¶ 61,306 (June 22, 2007).

[2] Comments of American Forest & Paper Association, Docket Nos. RM07-19-000 and AD07-7-000, September 14, 2007 ("AF&PA proposal" or "FPO proposal"). AF&PA submitted additional material in its informational filing, Docket No. AD08-4-000, April 3, 2008 ("Informational Filing").

[3] See, e.g., "2010/2011 RPM Base Residual Auction Results," February 1, 2008.

future investments. However, debating fundamental changes to a generally well-functioning system is likely to chill the investment climate just as it begins to gain momentum. Regulatory certainty and stability are critical components that must accompany market signals if efficient new investment is to take place.

FPOs would require generating units receiving capacity payments to financially guarantee the delivery of energy to the real-time energy market at or below a prespecified and regulator-determined price. Although FPOs could, in principle, provide consumers a hedge against energy price volatility, the trade-off would likely be a less reliable electric system. This is because the proposed mechanism creates perverse economic incentives for generation suppliers to delist (or export) their capacity resources, *especially* in high-LMP areas, where new capacity is needed most. In addition, FPOs will require participating generators to aggregate and absorb all financial risks without providing commensurate compensation. Not only will this increase the cost of financial hedging and thus raise costs in the short run, it also will reduce the economic incentives for new generation and demand response investments. Hence, one must ask whether the potential benefits of incorporating FPOs into the current markets are sufficiently greater than the potential costs.

The overarching question regarding the AF&PA proposal is whether there truly is a need for yet another new market design given that current power markets are working well.[4] Capacity markets are still maturing, considering the long-term nature of installed-capacity investments. Additional time is needed to allow these markets to work as intended and to make the necessary incremental refinements. Some of these markets (e.g., the ISO-NE Forward Capacity Market) are still in a transition phase, even though auctions to date have made important strides.

---

[4] Many authors have shown that wholesale competition has been successful, especially in markets in the eastern United States. See, e.g., Howard J. Axelrod, David W. DeRamus, and Collin Cain, "The Fallacy of High Prices," *Public Utilities Fortnightly*, November 2006. In the above-mentioned proceeding, FERC received numerous comments in support of the current market-based approach. A good example is the comment submitted by the COMPETE coalition, together with 81 other parties. The group included large customers such as Wal-Mart, industry experts, and Nobel laureates.

Section 2 of this paper provides a short account of the development of capacity markets in regions with organized wholesale markets. It also discusses the economic rationale for market-based capacity payments. Section 3 evaluates the fundamental components of the proposed Financial Performance Obligations. Section 4 discusses other open questions with respect to the implementation of the AF&PA proposal. The final section presents a summary of opinions.

2. The development of markets for installed capacity

The need to ensure electric system reliability has resulted in an evolving structure of the electric industry, including wholesale and retail restructuring efforts that have led to the creation of ISOs and RTOs. The 1965 Northeast blackout prompted the formation of the National Electric Reliability Council (NERC – now known as the North American Electric Reliability Corporation) in 1968. Subsequently, 10 regional reliability councils and "power pools" were formed to coordinate the operations of the many independent electric utilities and reduce the risk of future blackouts.

Before capacity markets were established, power pools required load-serving entities (LSEs) to procure specified amounts of installed capacity based on their peak loads plus a reserve margin. If a utility did not have sufficient resources to meet its requirement, it could either obtain it from an entity in the pool with a surplus or pay a deficiency charge.

The need for coordinating capacity requirements in a region arises from the *public good* nature of reliability.[5]As a result, as with all public goods, individual load serving entities left on their own will not provide enough system reliability because they can't reap the full economic benefits of doing so, and they would rather "free ride" on the capacity investments of others. Reliability targets establish the levels of installed capacity necessary to ensure there is enough generation available to meet consumers' electric demand at any point in time, much as operating standards ensure that generators do not operate in ways that compromise the safety and integrity of the transmission system.

---

[5] For a broader discussion on the public good nature of reliability, *see* Jonathan A. Lesser and Guillermo Israilevich, "The Capacity Market Enigma," *Public Utilities Fortnightly*, December 2005.

With the unbundling of the generation, transmission and distribution functions of LSEs, the controversy was less over the need for reliability standards and the associated need for market intervention to eliminate free-riders, but rather whether those obligations could be met by establishing a separate, long-term market in which the price of installed capacity is set by supply and demand conditions. More fundamentally, there has been a debate as to whether a well-functioning energy market would ensure sufficient capacity in the long run and eliminate the need for any separate long-run installed capacity "market."

It is clear that capping energy market prices serve to suppress legitimate price signals.[6] Consider peaking units as an example. Peaking units trade low capital costs for high operating costs, and thus are designed to run infrequently. Without any type of separate capacity payment, the owner of a peaking unit must rely on energy price spikes, which tend to be infrequent, to recover the capital investment. In the presence of price caps, however, a generation developer will be reluctant to invest, because the price caps limit needed returns. For the same reason, banks and other investors that are asked to finance such investments are less likely to provide the necessary capital.

In addition to price caps, generation developers must also contend with numerous financial risks. These risks are especially problematic for peaking and intermediate units that rely on high energy market prices to recover their costs. For example, high prices often spur allegations of anticompetitive behavior. Although anticompetitive behavior clearly requires intervention, high prices themselves do not necessarily mean that anticompetitive behavior exists; instead, they may reflect legitimate supply and demand conditions. But when price spikes make headlines, it is often tempting to politically intervene, or threaten to intervene, in the marketplace.

In this context, market designs with separate capacity markets and energy markets provide appropriate market signals that provide the incentive for the necessary investments in supply infrastructure. This not only reduces the risks from more volatile "energy-only"

[6] There have also been debates as to whether some forms of capacity market mitigation schemes also suppress legitimate price signals.

markets, it also provides a hedge against the inevitable regulatory and political pressures for energy market intervention when prices are high. And new generation investment, spurred on by a separate capacity market, will not only reduce capacity market prices but also increase competition in the energy markets. The result would be lower energy prices than might otherwise occur, plus improved reliability.

It is noteworthy that FERC and a number of individual states have favored market-based solutions to both short-term and long-term reliability issues. Policymakers have sought to replace cost-based arrangements with market-based ones because they believe market solutions can provide resource adequacy and security more efficiently than traditional, cost-of-service arrangements. The understanding is that a separate capacity market encourages suppliers to commit generating capacity into the market by providing predictable revenues and facilitating financing for new capacity.[7]

The long-term nature of capacity markets nonetheless presents a particular challenge to regulators and policymakers. Capacity investments are "lumpy" and require long lead times to build. Thus, capacity markets are designed to provide investors with a more stable and predictable stream of future revenues. PJM and ISO-NE have addressed the long lead time concern with forward capacity market auction designs. These market designs create a contractual agreement more consistent with the time necessary to develop or renovate generation capacity and transmission infrastructure. Regardless of the particular market design chosen, some form of forward commitment must be made in order to secure the demand response programs and generation resources sufficient to maintain a reliable system in the future. Although designers of even the most successful markets need to adjust and "fine-tune" their rules over time, they are reluctant to change the entire market construct, because investors would be exposed to regulatory uncertainty and would be less likely to invest in projects for the long term.

Finally, far from the price spikes observed in some energy markets, emerging capacity markets have shown prices generally below the long-term replacement cost of

[7] See, e.g., *Devon Power LLC*, 115 FERC ¶61,340.

peaking units, as shown in Table 1. Capacity prices have historically been low in the northeastern markets. While some generators have recovered replacement costs through scarcity rents in energy markets, many units needed for reliability required reliability must run (RMR) contracts or retired. In June 2007, PJM and ISO-NE implemented forward capacity markets, although ISO-NE has imposed fixed transition prices until the 2009–2010 season. So far, in both PJM and ISO-NE, forward auction prices have cleared below the projected cost of new entry. In the New York City control area, prices have historically cleared at or near generators' bid caps (based on 1996 cost-of-service calculations, before ConEd divested its generating units), while the NYISO region as a whole has shown prices well below the cost of new entry since 2001, and the recent strip auctions have shown prices around $1/kW-month.

Table 1: Capacity market prices ($/kW-month)

Period/Season	PJM	ISO-NE	NYISO
2005	0.16	0.20	4.38
2006	0.17	0.27	1.12
2007-2008	2.57	3.05	NA
2008-2009	3.88	3.75	NA
2009-2010	4.31	4.10	NA
2010-2011	5.31	4.50	NA
Cost of new entry	7.50	6.02	9.09

Notes: PJM UCAP prices are based on monthly averages in Capacity Credit Market until 2006 and Reliability Pricing Model auctions (pool average) starting in 2007-2008. ISO-NE ICAP prices are based on monthly capacity auctions until November 2006, administratively set transition prices starting in 2007-2008, and Forward Capacity Market auction in 2010-2011. NYISO prices are based on UCAP strip capacity auctions for NY City and Rest of Pool. No forward capacity market in place. Cost of new entry (CONE) is based on current demand curve for PJM, proposed demand curve for NYCA, and ISO-NE CONE for period 2011-2012 according to Market Rule Section III.13.2.4

3. AF&PA's financial performance obligations proposal

The AF&PA proposal properly recognizes that electric consumers want "safe and reliable service at just and reasonable rates" and that competition is not an end in itself but a means to deliver this product at low cost. The AF&PA proposal accepts two critical features of the Commission's market-based approach to today's power markets: locational marginal prices (LMPs) and capacity payments. Furthermore, the Commission and some industry participants view long-term contracts as a tool to help achieve a strong power infrastructure and effective competition. Long-term contracts may help allocate risk to the parties best able to manage it, mitigate the risk of market power abuses, and foster new generation and transmission investments.[8]

The FPO proposed by AF&PA would require units receiving capacity payments to financially guarantee the delivery of energy to the real-time market at or below a specified "strike" price. The strike price would be based on the marginal cost of the peaking unit used as a benchmark (i.e., the "proxy" unit) for the calculation of capacity payments.[9] As envisioned, the FPO has two components: (1) a capacity payment, as seen in some organized RTOs and ISOs, and (2) an attached energy contract in which LSEs pay a price equal to the lesser of the spot market clearing price or the marginal generation cost of the "benchmark" generating unit. Thus, the proposed FPO provides LSEs with a financial hedge in the form of a price cap for their real-time energy purchases from those units participating in the capacity market. And, as a result, the FPO also imposes a financial obligation and additional price risks on generation suppliers.

To encourage sufficient supply-side participation, the economic returns earned by generators must be commensurate with the accompanying financial obligations and risks they incur. This principle is embodied in basic economics and the long-standing "regulatory" compact. It is important because the FPO proposal does not incorporate any direct compensation for the proposed long-term energy contracts (and the risk) embedded with the capacity obligation.[10] In the short term, generators tend to be price-takers in capacity markets. Those prices may not increase sufficiently to reflect the additional contractual risk

---

[8] See, e.g., FERC NOPR, "Wholesale Competition in Regions with Organized Electric Markets," 122 FERC ¶ 61,167, at 130 (February 22, 2008).

[9] Capacity payments are designed to reflect annualized replacement cost of a peaking unit, including a reasonable return on the capital investment, minus the expected revenue margin that such a unit would obtain in the energy market. Several RTOs already use benchmark generating units to anchor capacity demand curves.

[10] AF&PA argues in its Informational Filing (p. 5) that the FPO creates an adjustment in an amount equivalent to the current Energy and Ancillary Services ("EAS") adjustment (or Peak Energy Rents ("PER") adjustment in ISO-NE). However, AF&PA does not propose to eliminate the EAS

that the FPO will impose on them.[11] As a consequence, generation owners will have additional economic incentives to "delist" their capacity if their capacity supply bids can not adequately incorporate the additional risks. This is certainly counter to the goals of the proposal. In the long term, to induce the capital investment required to maintain reliability, capacity prices must increase to the level that compensates for the financial risk embedded in the FPOs. The ultimate result will be higher capacity prices and less system reliability. As economics teaches, there is no such thing as a "free lunch."

Although capacity payments should, in theory, allow suppliers of pure capacity products (i.e., the benchmark peaking unit) to recoup their investment costs and earn a risk-comparable return on their capital investment, long-term energy contracts resulting from the FPO would limit capacity suppliers to recovering through energy charges no more (and sometimes less) than their marginal generating costs. The reason is that the benchmark unit cannot earn more than the strike price (equal to its marginal generation cost). However, in the real world of unexpected forced outages and high market prices, the benchmark unit would need to purchase more expensive power in the spot market and be forced to sell it at the lower strike price. Unless capacity payments are increased, generators will not be able to fully recover their investment costs.[12] As a result, the AF&PA proposal imposes a form of asymmetric regulation: generators' upside returns would be capped at regulated-like rates of return, but the downside risk will be unlimited. Not only would such a system likely be challenged by generators claiming that it does not meet FERC's "just and reasonable" standard, but investors will shun such asymmetric risk/return situations.

---

adjustment to capacity payments (*see* Informational Filing, p. 5). That adjustment would clearly be unnecessary if an FPO market is implemented.

11 All capacity markets closely monitor generator bids for economic and physical withholding. In addition, market power mitigation rules apply to suppliers found to be pivotal, particularly in load pockets. As such, generators do not typically have the ability either in the short term or in the long term to withhold capacity in order to obtain higher prices.

12 Although the strike price may be higher than the marginal cost of baseload units, it is the price that in the long-term market equilibrium compensates for those units' larger fixed costs.

The imposition of price caps, or of any financial obligation that has the same economic effect, would essentially extend cost-based regulation to the energy market and suppress legitimate price signals. Although some customers may welcome such a move falsely expecting that "more control" over generators will lead to lower power prices over the long term, many of those same customers sought to escape the well-documented problems of cost-based regulation in the early 1990s. FERC has tried to move away from cost-of-service regulation in capacity markets, such as reliance on RMR contracts. Given the significant capital investment required for new generating resources, yet another change in market design will have a chilling effect on new generation investment.

Under the FPO proposal, expected revenues for peaking units would be almost entirely determined by capacity payments and the strike price, both of which would be based on the benchmark unit. The FPO is designed to eliminate recovery of scarcity prices in spot energy markets.[13] As a result, it will effectively eliminate the price signals from the energy market that are needed to direct new investment in peaking capacity where it is needed. Simply put, the FPO would transfer risk from the energy market to the capacity market causing harm to reliability.

In addition, because the proposal would eliminate competitive energy bids (substituting a cost-based proxy), it leaves little margin for error in the choice of the technology and the benchmark costs for the proxy, because the entire market construct would depend on that choice. In designing capacity market demand curves for ISO-NE, PJM and the NYISO, questions regarding how best to determine appropriate proxy units and calculate construction and operation costs have been vigorously debated before the Commission. Under the FPO, administratively determining costs would be even more risky since, without the self-correcting mechanisms provided by a competitive bidding process, the FPO market will not work as intended if the assumed benchmark costs are wrong.

Another issue is that the FPO aggregates all idiosyncratic financial risks into the capacity price (e.g., risks related to contract performance, weather, forced plant outages, fuel

---

[13] *See* AF&PA Informational Filing, p. 7.

delivery, etc.). Under the current market system, risks can be allocated to parties that can most efficiently hedge those risks. But while generators may be able to efficiently hedge *some* financial risks, it is unlikely that they would be able to efficiently hedge *all* financial risks.[14] Forcing generators to hedge certain risks when others could do so more efficiently will increase the overall cost of risk management and, consequently, increase capacity prices more than necessary.

Creating markets from scratch is also a difficult task. The FPO proposal puts forward an additional mechanism to "incent" bilateral markets through mandatory, standardized long-term contracts negotiated jointly with capacity payments. Such standardized contracts may not appropriately reflect market participants' needs. Suppliers may not be able to make such financial commitments, and LSEs may want and need a different type of price protection. During the above-mentioned FERC NOPR on wholesale competition in organized markets, a majority of those who commented opposed the idea of requiring RTOs and ISOs to develop standardized forward products. Many participants expressed the view that the market is better equipped to do so. Others stated that long-term contracts vary considerably from transaction to transaction and that this fact makes standardized products difficult to develop.[15] Some parties further argued that different price expectations and risk assessments prevented long-term agreements.[16] As a result, the Commission avoided enforcing standardized long-term products and proposed to simply require that ISOs and RTOs dedicate a portion of their web sites for market participants to post offers to buy or sell electric energy on a long-term basis.[17]

---

[14] AF&PA proposes as the "most obvious" way for suppliers to hedge the risk of price volatility that they acquire additional physical supply (Informational Filing, p. 8). Although this would effectively hedge suppliers from the FPO, duplicating the installed capacity is arguably one of the most expensive hedging strategies.

[15] FERC NOPR, *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167, at 147 (February 22, 2008).

[16] Id., at 132. Some customers also argued that issues of market design and overreliance on the spot market had driven up prices, making long-term contracting difficult.

[17] FERC NOPR, *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167, at 129 (February 22, 2008).

Ill-defined contracts also create perverse incentives, because returns may not be commensurate with the risks imposed on participants, e.g., because of apparent "free lunches." This leads to the most troubling feature of the FPO. Constrained areas where new capacity is most needed (as evidenced by high LMPs and transmission constraints) will present higher risks for suppliers and, consequently, the FPO will discourage new capacity investments and generator commitments to provide capacity there. The reason is that generation suppliers will prefer to delist capacity whenever their expected returns from selling energy at market prices are greater than the expected returns from the FPO market. In addition, under the FPO, whenever a supplier experiences a forced outage, it must purchase energy at the (high) LMP and resell it at the (low) strike price. Therefore, for the same capacity payment and strike price (both of these based on the proxy unit), suppliers will have greater financial risk in high-LMP areas and less incentive to invest in high-LMP areas relative to low-LMP areas.

The Commission will then be faced with a difficult choice: either accept lower levels of reliability than the current 1-in-10-year loss of load expectation (LOLE) or impose regulatory mechanisms that prevent generators from delisting units, thus effectively returning to the cost-of-service based RMR contract approach, which the Commission has sought to eliminate.

The FPO also creates the wrong incentives for demand response programs. The fundamental idea of demand response is to give financial incentives to retail customers for voluntary and verifiable load reductions.[18] However, as recognized by AF&PA, the FPO allocates all of the short-term risk of market volatility to suppliers. And, in doing so, it reduces the incentive for demand response resources to be provided.[19]

At about five percent of nationwide peak demand, demand response capability has notably increased its participation in wholesale power markets. FERC's policy to further

[18] *See, e.g.*, ISO-NE 2005 Demand Response Program Evaluation, December 30, 2005, Section 1, p. 6.

[19] Informational Filing, p. 8.

eliminate barriers to the participation of demand response is based on the potential for demand response to lower wholesale prices, mitigate market power, flatten load profiles, and enhance reliability.[20] FERC intends to eliminate market features that inhibit LSEs and other demand response providers from bidding load reductions in response to market prices.[21] However, the demand response potential will not be realized if customers are hedged and do not face different prices for different load levels.

In addition to taking incentives for demand response resources *away* from customers, the FPO will also increase the risks to those who do provide demand response. Under the FPO, if a demand response provider bids for capacity payments and cannot deliver when called on, it is financially liable for the difference between the spot market price and the strike price. In this way, the FPO acts as a "double whammy" on demand response providers.

4. Other implementation issues

The AF&PA has outlined the basic mechanism and fundamentals for its FPO proposal. However, a number of thorny implementation issues would need to be addressed if the Commission decided to move forward with this proposal. For example, the FPO proposal does not address critical "seams" issues. The benchmark units used in PJM are not the same as those in the NYISO, and they may also differ within an RTO. For example, in NYISO, the benchmark generating unit in the New York City zone is not the same as "Rest-of-State." The benchmark unit is typically chosen based on the peaking technology that provides the lowest cost and is feasible to build in each region. More efficient, smaller-footprint units tend to be the technology of choice in heavily populated and congested areas.

With different technologies exhibiting different variable generation costs, FPOs in different regions will have different strike prices. The FPOs will then encourage generators to export power out of their local RTO whenever they expect strike prices to be higher

---

[20] *See* discussion in FERC ¶ 61,167, at 28-37.

[21] Id., at 42.

elsewhere. This will create reliability planning issues in those RTOs which experience increased power exports. A critical feature of the FPO proposal is the determination of the strike price. The strike price is based on the marginal cost of the benchmark unit and will need to be calculated on an hourly basis. Under the FPO, this regulated price will define the regional price cap for LSEs and generators. The AF&PA has not defined the algebraic methodology for the strike price and, given its deep impact on market participants, it is likely to lead to a long and contentious process.[22] One of the fundamental advantages of market-based prices is to avoid such processes.

Finally, either sellers or customers may avoid the FPO capacity market altogether and turn to the spot energy market if they consider the contracts disadvantageous. As mentioned above, if prices are expected to be high during peak demand periods, suppliers may choose to forego capacity payments (and the associated obligation to sell at marginal cost) in order to capture high spot energy prices. This will defeat the purpose of the FPO and exacerbate the reliability and price volatility problems the Commission has addressed with its policy on capacity markets.[23]

5. Conclusions

Long-term contracts attached to capacity payments which AF&PA hopes will result from its proposal may conceivably add some liquidity to wholesale markets. However, those contracts would not (and should not) be imposed by AF&PA's regulatory construct, and market participants have to be properly compensated for the financial hedging they provide. If sellers or customers consider such contracts to be disadvantageous, they may instead turn to the spot energy market and avoid them altogether. This will only exacerbate reliability

[22] Although demand curves in existing capacity markets include an EAS (or PER) adjustment that also depends on the marginal cost of the benchmark unit, a simpler approach is used, based on historical data, and known in advance by market participants.

[23] The incentive to delist capacity in high-LMP areas may also force the Commission to consider stronger market power mitigation rules or capacity obligations that begin to look very much like RMR contracts.

problems and thwart the Commission's goal of establishing and maintaining a viable, competitive generation market to ensure reliability.

Appendix A of this white paper compares the key features of the FPO proposal with those of the current RTO market construct. The proposed FPO would distort the fundamental price signals of competitive wholesale power markets. By extending cost-based regulation to energy markets and eliminating scarcity rents, it has the potential to deter investments from constrained regions in particular. It also forces generators to hedge certain risks, when other market participants could do so more efficiently, and it severely dampens incentives for customer demand response.

Finally, it is worth emphasizing that suppliers are less likely to invest in projects for the long term if they feel the rules of the market will change. In order to attract investors, power market mechanisms must be transparent, stable, and predictable. Restructured power markets are working well, and capacity markets are being developed to address long-term reliability issues in a manner consistent with the time required by new infrastructure developments. Unless market-based solutions have proven to have failed, *and they have not*, the AF&PA proposal likely will be perceived by investors as yet another midcourse change in capacity market rules. If so, it will discourage new generation investment and thus raise prices—precisely the opposite of what the AF&PA proposal seeks.

Appendix A: the FPO proposal vis-à-vis current RTO markets

Key features	Current RTOs and ISOs with capacity markets	FPO proposal
Energy prices	Result from supply and demand bids	Units receiving capacity payments obtain the lesser of the market price or the marginal cost of the benchmark unit
Capacity prices	Based on an administratively set demand curve and existing (or future) installed capacity	No change proposed
Expected long-term capacity prices	Reflect benchmark cost of new entry minus expected revenues from energy and ancillary services	Reflect cost of new entry plus supplier cost of financial hedging
Long-term energy contracts	Voluntary, through bilateral markets	Mandatory, at a standardized price, for units receiving capacity payments
Incentive for new investments	LMPs and capacity markets signal to potential investors of supply shortages and types of technologies needed	Capacity markets only signal long-term supply shortages, while LMPs deter investors from constrained areas
Party that has the incentive to develop demand response mechanisms	Customers	Marginal incentive for suppliers
Idiosyncratic financial risks	Through bilateral contracts, allocated to parties that can hedge risks efficiently	Suppliers
Fuel cost volatility	Customers and suppliers share fuel cost volatility	Suppliers
Extent of cost-based regulation	Capacity markets based on administratively set demand curves and benchmark costs	Both energy and capacity markets under cost-based regulation