American Public Power Association
2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4804
Ph: 202.467.2900
Fax: 202.467.2910
www.PublicPower.org

American Public Power Association Response to The Brattle Group's Open Letter to the U.S. Government Accountability Office on Electricity Capacity Markets

On May 5, 2016, four representatives of The Brattle Group ("Brattle") sent a letter to Dr. Frank Rusco, Director of Natural Resources and Environmental Issues for the U.S. Government Accountability Office (GAO). The purpose of the letter, also released to the public on Brattle's website,[1] was to provide Brattle's responses to the questions posed to the GAO on November 19, 2015, by Senate Energy & Natural Resources Committee Chairman Lisa Murkowski (R-AK) and Ranking Member Maria Cantwell (D-WA) regarding U.S. electricity capacity markets.

The American Public Power Association (APPA) has carefully reviewed Brattle's letter to the GAO and is concerned that many of the responses are misleading or unsupported by the available data. This document provides APPA's responses to these problematic claims.

The format of this document is as follows: Each question posed by Senators Murkowski and Cantwell to the GAO is copied below in bold, followed by claims or statements made by Brattle (in italics) that APPA has identified as problematic, and then APPA's own responses to these statements.

1. **We are concerned about the relationship of the increments of new capacity cleared in an auction and the increments of new capacity actually installed. Two recent surveys suggest that only a small fraction of new capacity has been built in organized markets except under bilateral power purchase agreements or direct ownership by LSEs [Load Serving Entities]. Additionally, it is our understanding that except for one sub-region within PJM, capacity has never cleared above the "cost of new entry" in PJM or MISO. These observations prompt us to ask a central overarching question:**

    1a. Since their establishment, how effectively have capacity markets influenced the construction, maintenance, or retirement of generation in order to ensure resource adequacy and reliability in a cost-effective manner?

<u>Brattle Statement</u>

This auction-based, competitive format has proven effective at leveraging competitive forces to attract the lowest-cost combination of available resources, including demand response resources and the refurbishment and upgrades of existing resources.

<u>APPA Response</u>

This is one of many broad statements in this letter that are made without support. In this case, there is no evidence provided in the letter that the resources clearing the capacity market auctions are in fact lower cost than would be procured under an integrated resource planning process and vertical integration, since no such counterfactual analysis has been conducted. What is known, however, is that each capacity

[1] http://www.brattle.com/news-and-knowledge/news/open-letter-by-brattle-economists-offers-responses-to-u-s-senators-questions-concerning-the-efficacy-of-u-s-electricity-capacity-markets

resource is paid the clearing price, regardless of its actual capacity cost, meaning that those resources with lower costs are receiving revenues in excess of their costs.

Brattle Statement

[C]apacity prices remain substantially below the system operator's estimates of the long-run cost for new generating plants. PJM's recent auction for the 2017/18 delivery year attracted nearly 6,000 MW of new generation commitments at prices that were 35–41% of PJM's estimated net cost of new entry (Net CONE).

APPA Response

While prices were below net Cone in PJM's 2014 Base Residual Auction (BRA), as noted in the prior response, all of the 167,000 megawatts (MW) that cleared the auction were paid the clearing price of $120 MW-month, although over 90 percent of the capacity was from existing resources or demand response, whose costs may be below net CONE, and in many cases, below the clearing price. For example, David Patton of Potomac Economics, the market monitor for the Midcontinent Independent System Operator (MISO), stated at a FERC technical conference that with regard to generating resources in MISO, other than very old units with high maintenance costs, "most of their going forward costs will be covered by net energy and ancillary service market revenues."[2] Many units in MISO are fully depreciated and have low- or zero- capacity cost, which is likely to be the case in other RTOs like PJM. (An exception is nuclear generation within the RTO markets, which is facing difficulties covering its costs, primarily as a result of declining energy prices.)

Brattle provides a reference to its own presentation in footnote eight[3] that provides a number of helpful reasons that new generation may clear below net CONE, including expectations of higher energy revenues and/or capacity prices in future years (as the auction price is just for a single year), and/or aggressive low bidding to clear the auction.

Brattle Statement

Increments of New Generation Cleared versus Built*.*

First, we note that there generally will be a difference between the quantities cleared and built. The magnitude of that difference is likely to be modest or consistent with a decline in load forecasts for the delivery year. The APPA reports do not attempt to quantify this magnitude or explain the reason for any difference, perhaps because the timing of the reports would have made such a comparison impossible. The latest APPA report was issued in 2014, but it was not until the 2015 delivery year that significant new generation was committed to come online.

Second, if there is some discrepancy between original commitments and actual construction, it is most likely related to the fact that PJM's three-year load forecasts have been overstated compared to the subsequently-revised forecasts for the delivery year. As a result, PJM has procured more capacity in the three-year forward auction than what was actually needed.

[2] Technical Conference on MISO Planning Resource Auction, Docket Nos. EL15-70 EL15-71, EL15-72, and EL15-82, October 20, 2015, Transcript, p. 80-81, http://www.ferc.gov/CalendarFiles/20151123093656-MISO-10-20-15.pdf

[3] "PJM Capacity Auction Results and Market Fundamentals," Samuel Newell, David Luke Oates, and Johannes Pfeifenberger, Brattle Group, Prepared for Bloomberg Analyst Briefing, September 18, 2015, http://www.brattle.com/system/publications/pdfs/000/005/204/original/2015-09-18_Newell_Webinar_on_PJM_Capacity_Market.pdf?1444083408

APPA Response

In December 2015, APPA issued another study of new power plant construction. This study covers generating capacity that came on line in 2014 and contains additional information raising some questions about how much of the new merchant generation will be constructed, including reports of delays and uncertainty at three merchant plants, totaling almost 3,000 MW, along with quotes from other experts.[4]

APPA did not in its reports quantify the magnitude of merchant delays or cancellations as such data is not available. PJM does not release the identity of which plants cleared the auction and whether the plants that cleared were actually built and when they begin service. But a recent paper by Monitoring Analytics, PJM's market monitor, projects that based on historical completion rates, just 70 percent of the market-funded projects that cleared the PJM capacity auctions are expected to go into service, meaning that about 5,000 MW of cleared merchant generation will not be completed. In contrast, 88 percent, of non-market funded projects are expected to go into service, a 500 MW discrepancy between cleared capacity and completed projects.[5]

There is no evidence that the delays in merchant builds are a result of changes in PJM forecasts since these plants have already cleared the auction and have a commitment provide capacity. It is likely that at least in some cases an expectation of reduced prices in future years resulting from lower load forecasts could be a cause of delays or possible cancellations. But the supplier would still receive a payment for its capacity that cleared the auction. If a project is not completed, the seller could buy out its capacity obligation from another supplier in an incremental auction. The difference between the capacity price and the cost of the same amount of capacity in the incremental auction represents a payment to the generation owner and a cost to consumers that would still occur.[6]

A fundamental difference between the nature of generation constructed by a regulated utility and a merchant owner is illustrated in Brattle's letter on p. 13:

> It is also the case that vertically-integrated utilities have an obligation to serve and so often cannot retire an asset until a replacement is arranged, which may take some time to develop. In contrast, a merchant plant owner can close its operations whenever the going forward economics no longer look attractive.

While this statement may have been intended to demonstrate that uneconomic plants may be more quickly retired by merchant owners, it also shows the uncertainty that accompanies merchant capacity.

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[4] "Capacity Markets Do Not Incent New Generation," American Public Power Association, December 2015, p. 9. The three plants with uncertain futures discussed in the report are the Hickory Run, Westmoreland and Lebanon Valley. Since that report, construction was initiated last month on Westmoreland, after seven years of delays (http://triblive.com/news/westmoreland/10334056-74/power-plant-tenaska) but not on the other plants.

[5] "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/19," Monitoring Analytics, May 4, 2016, p. 10-11, http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf

[6] PJM concerns about the possible speculation and arbitrage between the Base Residual and Incremental Auctions led to the filing of proposed tariff changes in Dockets ER14-1461 & EL14-48 which FERC did not accept and instituted a Section 206 proceeding. PJM has since requested that action under this docket be deferred until PJM can gather data to determine if the capacity performance rules may have mitigated the speculation. See "Report and Request for Continued Deferral of Action in the Replacement Capacity Proceeding of PJM Interconnection, L.L.C. under ER14-1461, et. al.", October 29, 2015, http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14394025

Brattle Statement

[A]s a partial comparison, approximately 18,000 MW of new (not refurbished or life-extended) traditional thermal capacity has cleared PJM's capacity auctions starting with the delivery year 2015/16. That compares to 13,500 MW that have either come online or are currently under construction.

APPA Response

These numbers are comparing two different things. The 13,500 MW represents capacity in PJM that has already been built or is under construction and just partially overlaps with the total 18,000 MW that cleared all the auctions, a significant portion of which cleared for future delivery years and has not yet been built. Moreover, the 13,500 MW already constructed is primarily non-merchant, as confirmed by footnote 21 in the Brattle letter, which states that prior to the auction for the 2016/17 delivery year, "a substantial quantity of new generation did clear in prior PJM auctions, but the large majority of those resources were likely LSE self-supply (although PJM did not report precise statistics on the portion designated as merchant until the 2016/17 auction)." The 18,000 MW is a mix of merchant and non-merchant plants. As the previously cited Monitoring Analytics report showed, not all of the cleared new capacity will be built.

Brattle Statement

Prices Below the Net Cost of New Entry (Net CONE).

As the Senators noted, prices have been below the administrative estimates of Net CONE in most of the capacity markets for most auction years in ISO New England, New York, and PJM. We do not see this as a concern for these three markets. Rather, we view this as evidence of beneficial competitive market performance.

APPA Response

See the prior response on page 2. Prices are paid to all resources, with many different costs, many of which are likely to be below net CONE and below the clearing price. APPA does not view the problem of capacity prices as whether they are above or below net CONE per se. Rather, the flaws in the pricing are that 1) the same price is paid to all units regardless of their age, technology, or actual costs and 2) the prices are extremely volatile, impeding rational planning decisions about new generation builds, upgrades, or retirements.

Brattle Statement

Generation Being Built Under Contract with Load Serving Entities (LSEs).

It is not correct that new generating capacity has been built only under bilateral agreements with LSEs or under direct ownership by LSEs, although this was likely the case up until the 2011 and 2013 periods examined by the APPA studies. Until those years, competition from lower-cost resources had postponed the need for new generation, which meant that no private entity would make an investment without a long-term contract. Thus, in those years with excess supply, only regulated entities with cost recovery were building generation or signing contracts to build new generating plants.

APPA Response

APPA has conducted analyses of all new generation that came on line in the years 2011, 2013, and 2014. For each study, the generation was categorized according to whether the financing for those projects was a long-term contract, or utility or customer ownership, or solely based on revenues received from sales into the wholesale markets. (This last category also includes projects for which no information was available about their financial arrangements.) These analyses, based on a comprehensive review of publicly available data are that the following percentage of new capacity, across all RTO and non-RTO regions, was built for sale solely into the markets: 2011: 2 percent; 2013: 2.4 percent; 2014: 4.8 percent. It is hard to see the basis for Brattle's conclusion that the predominance of contracts and ownership is not a correct observation.

Brattle attributes the high percentages of non-market sales to a theory that new generation was not needed and therefore only regulated entities would undertake such new generation. As with other statements, there is no evidence that regulated entities are undertaking new builds in spite of a surplus or that merchant developers avoid doing so. As coal plants retire, many utilities are seeking to replace this capacity, as well as to meet policy or regulatory objectives. Moreover, APPA found that a significantly larger share of the new generation (17.6 percent) in 2014 compared to prior years was constructed without a utility, but under a PPA or hedge instrument with a financial entity. This shows that a predictable stream of revenue is still needed for capital projects, even where a utility is not the sponsor – the fundamental point of APPA's studies. Finally, as merchant supply has increased in recent years in PJM, capacity has been procured in excess of the reserve margin, meaning that merchant generation is in fact continuing to plan new units in times of surplus.[7]

2. Maintaining resource adequacy and reliability are essential requirements of any electric power system. As described above, RTOs/ISOs have developed various approaches to maintaining reliability through capacity markets. In regions without organized markets, reliability criteria such as planning reserve margins are typically established by states or balancing authorities. In those regions, the costs of new capacity to meet reliability criteria must be approved through traditional cost-of-service rate regulation, usually through a state utility commission or a consumer-owned utility board.

2a. How do capacity costs borne by wholesale customers (including costs passed-through to end-use customers) compare among consumers subject to mandatory capacity markets, voluntary capacity markets, and traditional rate regulation?

Brattle Statement

Before responding to the question, we clarify that we do not distinguish between mandatory and voluntary capacity markets in this response. MISO's capacity auction is labeled as "voluntary," but it is voluntary in name only. LSEs would face substantial penalties if they failed to procure enough capacity to meet their requirements. A truly voluntary capacity market that did not impose any penalty for falling short would not be a workable construct.

APPA Response

With all due respect, this statement shows a complete misunderstanding of how the terms "mandatory" and "voluntary" are used in the context of capacity markets, and therefore confuses the discussion. A voluntary capacity market is one where load-serving entities are not required to offer and clear all their resources through the capacity market, and does not mean that the reliability standards are in any way voluntary. FERC sums up the issue well in its order on MISO's proposed changes to its resource adequacy construct[8] (emphasis added):

> Nor do we agree with Capacity Suppliers that the current capacity market – i.e., one that is based on a *voluntary capacity auction* – is insufficient to ensure reliability over the long term. We addressed that particular issue in the Financial Settlement Order. Specifically, the Commission held, "[w]e

[7] In the PJM Base Residual Auction procuring capacity for the 2019-20 delivery year, the reserve margin was exceeded by almost 6 percent, and there was 3,800 MW of merchant-built capacity clearing the auction. See "2019/2020 RPM Base Residual Auction Results," http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx

[8] Order on Resource Adequacy Proposal, 139 FERC ¶ 61,199 (June 11, 2012), P. 43.

reject arguments that a *mandatory auction or a mandatory centralized capacity market* is necessary to ensure resource adequacy."

Brattle Statement

We first address the question of whether restructured capacity markets or traditional rate regulation have produced lower capacity costs. As a theoretical question, the answer is that a traditionally-regulated system and an efficient market-based system should expect to produce similar total customer costs under idealized conditions. However, the two constructs differ in who bears the risk of investments becoming uneconomic due to unforeseen events and trends. In a traditional rate-regulation construct, investment costs are passed to ratepayers so that customers pay for the costs of uneconomic investment decisions. In contrast, restructured markets require supply-side entities to absorb those risks, with uneconomic investments translating to financial losses to the investors. This shifts investment risks from consumers to suppliers.

APPA Response

This is a restatement of an often-made claim – that a benefit of the restructured markets is the shifting of risk from consumers to shareholders. APPA urges the GAO to carefully examine this claim in this report. While the claim is facially logical, observations of the history of the RTO markets shows that such a shifting of risk rarely occurs. Instead, the rules of the markets are continually retooled in response to concerns about sagging merchant generator earnings. The very creation of the capacity markets themselves was in response to claims of "missing money" and the need for an additional administratively-run revenue stream. Later, when several states sought to take control of resource decisions and procure capacity through competitive processes outside of the capacity constructs, once again claims were made by merchant generation owners of the need to "protect" market participants from the "out-of-market" actions through buyer-side mitigation.

The lack of an appetite for risk by the merchant generators was apparent in the testimony of John Shelk of the Electric Power Supply Association before the House Energy & Commerce Committee's Subcommittee on Energy and Power last June, where he noted that, with regard to declines in wholesale energy prices, "one might conclude this is a boon for consumers, but on further inspection it is at best temporary if the present situation is not sustainable for certain power plant and the long-term overall health of wholesale markets. The reason is that no business asset can survive for long if it cannot recover its costs plus an adequate risk-adjusted return of and on invested capital."[9] In other words, the risk of falling prices is not acceptable to the sellers in this market, but consumers are not protected from higher prices and the payment of rent to generators.

Brattle Statement

"Capacity costs" are not transparently tracked in traditionally-regulated regions. While the capital costs of a regulated utility may be substantial, those costs are not unbundled from the rest of the utility's costs and consequently are not available to the public in simple terms of price and quantity.

APPA Response

This statement is simply not correct. Regulated utilities, whether they are investor-owned, public power, or cooperative, are overseen by a state or local regulatory authority that reviews their costs before approving their rates. All of the actual costs, including capacity and energy costs, depreciation, and the cost of capital, are reviewed periodically to ensure that investor-owned utilities do not earn more than their regulated rate of return and that public power and cooperative utilities meet their not-for-profit

[9] "Statement of the Electric Power Supply Association," John Shelk, President and CEO, US House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power, June 4, 2015, http://docs.house.gov/meetings/IF/IF03/20150603/103551/HHRG-114-IF03-Wstate-ShelkJ-20150603.pdf

status. Depreciation of rate base, replacement of physical plant with energy efficiency, and other cost reductions would be accounted for in the rates charged to customers. In contrast, merchant generation's actual costs are not available to the public. The only available information is the capacity *prices* for a given year, but as explained earlier, such prices do not reflect actual costs, and in many cases can exceed them.

No consumer in either regulatory scenario sees the capacity costs as an unbundled component of the energy costs. Instead, in retail access states, the consumer simply sees a bundled rate for "generation" with no indicator of the components of that rate and whether that rate is a reflection of actual costs.

<u>Brattle Statement</u>

[W]e suspect that a valid comparison would show lower costs in capacity markets compared to traditionally-regulated regions in many (but not all) cases. We take this view primarily based on the observation that capacity markets have attracted a large quantity of low-cost resources that regulated planning likely would not have identified as supply options.

There is no empirical evidence that capacity markets produce lower cost mix of resources, and there are reports of the opposite. A recent paper[10] by the Energy Policy Group LLC illustrates the benefits of integrated resource planning (IRP) by vertically-integrated utilities in comparison to the capacity markets, and finds that:

> [I]n centralized markets, there is no means by which to ensure that generation decisions will be made based on lowest overall costs. In fact, the opposite may be true, especially where merchant generators do not face the full costs of transmission improvements that are needed at the location chosen by the generator. If these costs are socialized, as is currently the case in several of the centralized markets, then retail customers are ultimately paying the costs of poor location decisions. In fact, generators may be incented to locate where land, water, and fuel is the cheapest, without regard to incremental transmission costs or the overall impact to customers. Again, IRP in vertically-integrated, bilateral markets addresses this problem by ensuring that transmission (and all other) costs are included when making resource decisions…. Finally, in centralized markets, there is a loss of economies of scope that come from joint planning and operation of generation and transmission.

The only support provided for Brattle's finding that "capacity markets have attracted a large quantity of low-cost resources" is a footnote, noting that "the PJM market has seen a significant increase in demand response." But there is no evidence that demand response is more prevalent in RTOs with capacity markets, or even in RTO regions as compared to the other regions. Retail programs provide almost as much demand response as do RTO-operated programs.[11] Moreover, the five regions with the greatest expected levels of demand response in 2016 include just two RTOs, only one of which has a mandatory capacity market (PJM) and the other having a voluntary capacity market (MISO). The region with the greatest level of demand response is Florida.[12]

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[10] "Competition in Bilateral Wholesale Electric Markets: How Does it Work?" Prepared by the Energy Policy Group, LLL for the Electric Markets Research Foundation,
February 2016, http://www.emrf.net/uploads/3/4/4/6/34469793/bilateral_markets_white_paper_final.pdf

[11] "Assessment of Demand Response and Advanced Metering," Staff Report, Federal Energy Regulatory Commission, December 2015, http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf. Tables 3-2 and 3-3 show that in 2013, retail programs provided 27,100 of available demand response, while the RTO-operated programs provided 28,800 MW in that same year.

[12] Calculated based on data provided in the "Long Term Reliability Assessment 2015," North American Electric Reliability Corporation (NERC), Peak Season Demand, Resources and Reserve Margins, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf. The percentage of load reduction from demand response is expected to be 6.6 percent in the Florida region, 5 percent in PJM, 4.7 percent in the Southeast region of the Southeast Reliability Corporation, 4.4 percent in the

2b. Are there differences with respect to resource adequacy or reliability (historical, current, or projected) among regions covered by mandatory capacity markets, voluntary capacity markets, and traditional rate regulation?

APPA does not have any responses to Brattle's statements with regard to this question that have not yet been stated in other responses.

2c. Are there differences in the generation mix (including with respect to characteristics such as fuel diversity and firm versus intermittent service) among regions covered by mandatory capacity markets, voluntary capacity markets, and traditional rate regulation as a result of different market structures?

<u>Brattle Statement</u>

Capacity Markets Enable a Wider Range of Resource Options, Including Innovative Technologies*. When making planning decisions, regulated utilities are often only able to consider a modest number of potential resource alternatives. In contrast, capacity markets invite any and all potential resources and technologies to be employed, as long as they meet the technical requirements. Thus, a capacity market can attract a wider range of market participants and spur innovation in a wider range of low-cost supplies than a traditionally-regulated utility would be able to consider. This competitive format opens opportunities for non-traditional technologies such as demand response. As illustrated in Figure 1, PJM has attracted large quantities of demand response, starting with 2,100 MW in 2007/08 to clearing more than 11,000 MW in its most recent auction. Traditionally-regulated regions tend to have a much smaller share of demand response.*

<u>APPA Response</u>

Brattle provides no support for the statement that a capacity market can attract a wider range of market participants and spur innovation in a wider range of low-cost supplies than a traditionally-regulated utility. In fact, the capacity markets do not consider important policy factors, such as fuel diversity or lower carbon emissions, and the new generation clearing the PJM and ISO New England (ISO NE) capacity markets has been dominated in recent years by natural gas generation, producing a potential mono-culture of generation. Brattle itself notes on p. 12 its response that it is the regulated regions, and not the capacity markets, that can consider multiple factors:

> Regulated planning may be focused on lowest costs only as one of several objectives. Other objectives may focus on achieving specific environmental goals, fuel diversity, local jobs, technology development, or utility asset ownership.

Given the growing nuclear plant retirements in RTO regions and the adverse impact on carbon emissions, it is important to note that, on page 15, the Brattle states that:

> More importantly, in some cases, avoiding the retirement of a nuclear plant can be the lowest-cost option from a societal perspective that values the reduction of CO_2 and other emissions. A nuclear plant in a capacity market region may therefore be more likely to retire than a nuclear plant in a regulated region that considers the value of reduced CO_2 emissions in the planning process.

As stated previously, the levels of demand response are comparable between RTO and non-RTO regions. Brattle's response provides only PJM data and not that for other regions. Moreover, the demand response in PJM should be discounted, because as compared to other capacity resources, which are primarily generation, a significant percentage of demand response providers buys out their capacity obligations in Incremental Auctions that occur closer to the delivery year, equal to 4,829 MW or 31

Rocky Mountain Reserve Group of the Western Electric Coordinating Council and 4 percent in the Midcontinent ISO.

percent of the total demand response for the 2015-16 delivery year and 6,731 MW or 45 percent for the 2014/15 year.[13]

2d. Are capacity market rules contributing materially to broad scale premature retirements of in-service baseload units?

APPA does not have any responses to Brattle's statements with regard to this question that have not yet been stated in other responses.

3. The capacity markets in three RTOs/ISOs with mandatory markets have design differences. These differences range from treatment of non-generation resources such as demand response and energy efficiency to varying opportunities for LSEs to self-supply capacity.

3a Please identify any inherent market design considerations that explain limitations on the ability of LSEs to self-supply in mandatory capacity markets in PJM, ISONE, and NYISO.

3b. To what extent is the status of industry restructuring (with respect to generation ownership and rate regulation) a factor in limiting the ability of LSEs to self-supply within the states subject to mandatory capacity markets?

<u>Brattle Statement</u>

A Subset of New Generation Builds Is Subject to Minimum Offer Price Rules*. PJM, ISO-NE, and NYISO impose so-called "Minimum Offer Price Rules" (MOPR) on some types of new generation investments. The details differ among the markets, but the purpose of these rules is to prevent large LSEs or state agencies from building uneconomic generation in an attempt to artificially suppress capacity prices for the remainder of their capacity needs. When MOPR limits are imposed, an LSE will be required to offer the new generator into the capacity auction at a price that is no lower than the costs of the plant. This means the LSE will be able to use the plant for self-supply only if the plant is found to be lower-cost than market alternatives. Each of the capacity markets incorporates a number of exemptions to these rules to avoid imposing this restriction on LSEs that are not attempting to artificially suppress market prices.*

<u>APPA Response</u>

There is no evidence that large LSEs or states would undertake an expensive capital investment solely to lower prices. Instead, they may choose to invest in new resources to serve their customers and meet certain policy needs. Such an investment is not an "artificial" lowering of prices, but is an increase in supply that according to the basic laws of supply and demand would produce lower prices.

The statement that "each of the capacity markets incorporates a number of exemptions to these rules" is not correct. PJM did submit and receive approval for a self-supply and competitive entry exemption, which is now being challenged by a group of merchant generators. ISO New England does not provide any self-supply exemptions, and while FERC approved self-supply exemptions in the NY ISO, the ISO's proposed tariff changes to implement these exemptions have been challenged by the New York Power Authority, the New York Public Service Commission, and the New York State Energy Research and Development Authority because "certain elements of the exemptions are fashioned in such a manner that they will cause the [Self-Supply Exemption] SSE and [Renewables Exemption] RE to be difficult to qualify for and to maintain, which may thereby render these exemptions ineffectual."[14] Similarly, the

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[13] "2015 State of the Market Report for PJM," Monitoring Analytics, March 10, 2016, Section 5 – Capacity Markets, Table 5-10, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2-sec5.pdf

[14] "Protest of the New York Public Service Commission, the New York Power Authority, and the New York State Energy Research and Development Authority to the New York Independent System Operator, Inc.'s Compliance

New York Association of Public Power concluded that under the ISO's proposed restrictive methodology for determining exemptions, the market rules "will continue to impose unjust, unreasonable, or unduly discriminatory ICAP market restrictions on load-serving entities that have limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices."[15]

The Brattle Group then acknowledges the limitations of the MOPR exemptions in its response to question 3b on page 16 (emphasis added):

> In PJM, MOPR restrictions do not apply to such entities, and NYISO has proposed a similar exemption. In ISO-NE (and currently in NYISO), MOPR rules do apply, which imposes the unique risk that new self-supply resources that were deemed to be cost effective by an LSE in the planning process may face a minimum offer pricing restriction that does not allow the resource to clear in the capacity market. *This could result in substantial additional costs to the affected LSE, which could be burdened with both the cost of the self-supplied resource and capacity market charges for the load that was supposed to be covered by that resource*. LSEs are able to manage some of these risks (as discussed above), but not without some restrictions.

3c. Based on capacity market outcomes in the various RTOs and ISOs (both voluntary and mandatory markets), what appear to be best practices and market designs in terms of auction frequency, forward time periods (*e.g.*, 1-year versus 3-year versus other periods), market power mitigation, and LSE self-supply options?

APPA does not have any responses to Brattle's statements with regard to this question that have not yet been stated in other responses.

3d. Are there any mechanisms within the RTO/ISOs to account for the degree to which capacity market revenues overlap with revenues from other market features also designed to ensure resource adequacy and reliability such as shortage pricing?

<u>Brattle Statement</u>

Capacity revenues reward resource adequacy value. Net energy revenues reward low-variable-cost generation and performance during periods of energy scarcity/shortage pricing. And ancillary services revenues reward flexibility (with higher prices during scarcity). These three revenues sources are complementary and not-overlapping because the more net revenues a resource earns in the energy and ancillary services markets, the less it needs to earn in the capacity market to recover its fixed costs. This means suppliers' expectations of higher scarcity prices in the energy and AS markets lead them to offer their capacity at lower prices, resulting in lower capacity clearing prices. The same logic is applied to the administrative pricing parameters in the capacity demand curves. Higher energy and shortage prices will result in a lower administrative estimate of the long-run marginal cost of new capacity.

<u>APPA Response</u>

The first portion of the response refers only to suppliers' behaviors and not the actual revenues earned or any mechanisms in the markets. An individual supplier may or may not alter their capacity market offers in response to changing energy prices, but is not required to do so since their revenues or rate of returns are not regulated. Moreover, what a seller actually earns depends largely upon the behavior of the marginal unit. If an individual supplier, for example, lowers their capacity offers in response to greater energy prices, but the marginal capacity offer sets the price above that offer, then that unit could be earning significantly above their costs. In addition, the capacity offer is for three years in the future in

Filing," Dockets EL15-64 and ER16-1404, May 31, 2016, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14262109

[15] "Protest of the New York Association of Public Power in Response to Compliance Filing," Dockets EL15-64 and ER16-1404, May 31, 2016, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14262167

PJM and ISO NE. While a capacity seller may have a reasonable prediction of energy prices, they cannot predict the level of scarcity pricing events that may occur in the delivery year and precisely adjust their capacity offers.

As for the administrative estimate of the long-run marginal cost of new capacity, or the Cost of New Entry (CONE), PJM determines the net CONE by subtracting expected Energy and Ancillary Services (EA&S) revenues that would have been received by the reference unit used for the calculation of net CONE based on the three years of energy prices preceding the Base Residual Auction, gas prices, and the heat rate of the unit. Not only does this not provide the actual energy and ancillary services revenues received by each individual unit, but is an estimate for a delivery year three years in the future based on revenues for the past three years. As Brattle summarized in a recent analysis for PJM:[16]

> An E&AS offset based on three years of historical prices can be easily distorted by anomalous market conditions that are not representative of what market participants expect in the future RPM delivery year. The threat of significant distortions due to unusual historical market conditions has increased with PJM's new shortage pricing rules that will magnify the impact of shortages. For example, unusual weather or fuel market conditions can cause prices to spike, increasing E&AS revenues beyond what a generation developer would expect to earn in the future under more typical weather conditions.

In sum, there is no mechanism in the markets to measure or account for overlap between different revenue streams in different markets. To say otherwise, is not correct.

[16] "Third Triennial Review of PJM's Variable Resource Requirement Curve," Prepared by the Brattle Group for PJM, May 15, 2014, http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-vrr-curve-report.ashx Brattle does find that E&AS revenues used to calculate net CONE had been overstated, but nonetheless concludes that they are not an actual representation of actual revenues.