UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Centralized Capacity Markets in Regional Transmission Systems and Independent System Operators	**AD13-7-000**

STATEMENT OF JOHN MOORE, THE SUSTAINABLE FERC PROJECT

I am pleased to provide views on centralized capacity markets on behalf of The Sustainable FERC Project (the "Project"), where I am a senior attorney. This Statement focuses primarily on the questions in the third panel of the September 25, 2013 Technical Conference on this topic: the impacts of state and federal clean energy policies, emerging technologies and other developments on current centralized capacity markets, and potential market design changes necessary to account for these developments and assure grid reliability.

I. Introduction and Summary of Comments

The Project is a coalition of environmental and other public interest organizations, housed within the Natural Resources Defense Council, with member organizations throughout the United States. The Project and its partner organizations engage in Commission proceedings involving transmission grid planning, operations and markets. The Project and its coalition members also are active stakeholders in RTOs, ISOs and other FERC-jurisdictional entities throughout the country.

The Project's priority is to facilitate the transition to a low-carbon, environmentally cleaner energy future through better integration of renewable energy technologies and demand-side resources into the bulk power electric grid. These resources will account for close to 20% or more of all resources in organized wholesale electricity markets in the next seven years, with

higher levels in California and parts of the Midwest. With the advent of policies to address climate change, these resources will become dominant by 2050. Cost-effective and reliable integration of these resources requires comprehensive system planning that includes comparable treatment of non-wires transmission solutions and the removal of barriers to integration and market participation by renewable and demand-side resources. Ensuring that capacity markets do not prohibit but instead help to accomplish these objectives is one of the Project's top priorities.[1]

As we explain in more detail below, centralized capacity markets are a tool in service of a reliable, cost-effective and efficient grid; they are not an end in themselves. Capacity markets should be viewed as one of several potential mechanisms to meet fast-changing grid needs. Within the next generation, renewable energy and energy efficiency will constitute a majority of resources in some regions of the country. Depending on the wholesale market, and the states' ability to participate as partners with RTOs in long-term grid and resource planning, current capacity market designs may not be the most cost-effective solution to address evolving needs. Other solutions, such as flexibility enhancements to existing markets or creation of new markets, may be better suited to address future needs. Where markets are necessary, they should facilitate rather than frustrate entry of cleaner and more flexible resources, and not sustain uneconomic older and less flexible resources.

With these considerations in mind, this Statement discusses current and likely future drivers of a sustainable, cost-effective and reliable resource mix, some of the barriers that cleaner and more efficient resources face in current capacity markets, and potential solutions.

---

[1] In addition to capacity market reform, the Project's other priorities include: 1) a transmission planning process that accounts for public policy drivers affecting system needs; 2) comparable treatment in planning and markets for demand response, energy efficiency, energy storage and other emerging non-transmission alternatives; 3) rules and markets which maximize the reliable and cost-effective integration of clean energy resources into the grid; and 4) minimizing the use of reliability must run arrangements for uneconomic fossil plants.

II. Major Drivers of Change

Assuring a reliable supply of power to customers is a fundamental goal of centralized capacity markets. While we can count on the need for resource adequacy continuing into future, the ingredients of our energy system are rapidly shifting and changing – and with that our framework for defining and delivering cost-effective system reliability. We can look to a future where renewable energy will account for the majority of the energy supply on the grid, and where new technologies and a more dynamic, interactive grid will create both economic development and a cleaner environment.

Among the drivers of this change are clean energy standards (including some carbon standards), federal clean air and other environmental pollution standards, expanding use of energy efficiency and demand response resources, and the dramatically lower costs of variable renewable energy generation. We also expect renewed federal attention to climate change, beginning with carbon regulations for power plants, which are the single largest source of global warming pollution in the United States.

Current centralized capacity markets unquestionably should take into account the effects of these federal and state energy and environmental policies. Many of them directly influence the composition of grid energy resources. Failing to accommodate, integrate or coordinate with these policies could result in unjust and unreasonable wholesale rates in capacity markets.

Most of these policies also constitute public policy requirements ("PPRs") as defined in the Commission's Order No. 1000, which requires that public utility transmission planners take PPR-driven system needs into consideration in the grid planning process. As explained in Order No. 1000, the PPRs "are facts that may affect the need for transmission services and these needs

must be considered for that reason."[2] For this same reason, capacity markets and other resource adequacy tools must account for PPRs in their design and operation.

A. Renewable Energy Standards and Related Drivers

Renewable energy standards specify minimum amounts of renewable energy which retail utilities must supply to their customers. These state (and some municipal) standards are significant drivers for the construction of new wind, solar and other renewable energy power facilities. Twenty-nine states and the District of Columbia have adopted renewable energy portfolio standards applying to 54% of total U.S. retail electricity sales;[3] 21 of these states are in wholesale electricity markets. The national average of these targets is approximately 17% by 2020, with highs of 33% in California and 20% or more in several other states.[4]

While wind and solar photovoltaic are the dominant resources in most of these standards, others include: solar thermal, ocean thermal, wave, tidal, wind, biomass, hydro, landfill gas and fuel cells. Among the trends likely to accelerate across the country over the next decade, solar could overtake wind in total installed power, and offshore wind energy will take hold. (Relative to onshore wind, offshore wind generally will have higher capacity factors and a higher coincidence of output with peak demand.)

In addition to state standards, other drivers include state and utility resource planning requirements, principally in Midwestern and Western states. State energy funds also encourage renewable energy projects in some jurisdictions, as do tax incentives. Some states also have carbon-reduction policies.

---

[2] Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils., Order No. 1000, 136 FERC ¶ 61,051, at P 109 (2011).

[3] Barbose (LBNL), *Renewables Portfolio Standards in the United States: A Status Update*, slides 4, 6 (available at http://www.cleanenergystates.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf).

[4] In Minnesota, Xcel's obligation is 30% by 2020. *Id.* slide 4.

B. Energy Efficiency Standards

Energy efficiency is a significant utility system resource and the nation's electricity markets need to fully incorporate this resource into their planning and resource acquisition frameworks. Energy efficiency resources reduce overall customer energy demand, including during peak periods. According to numerous studies, energy efficiency is often the most cost-effective energy resource, and it can be a viable solution for distribution and transmission system needs. 25 states have adopted energy efficiency resource standards, which by 2020 will save energy amounting to over 6.3% of total energy sales nationwide (equivalent to the combined electric consumption of Maryland, Washington, Minnesota, Vermont and Rhode Island).[5] Nearly a dozen states are now achieving incremental annual savings equivalent to 1% of total sales or more.

Federal appliance, lighting and equipment standards also are significantly reducing electricity demand. Considering all products sold since the inception of each national standard from the mid-1980s through 2035, cumulative energy savings from these standards will reach more than 200 quads, an amount equal to about two years of total U.S. energy consumption.[6]

C. Distributed Generation

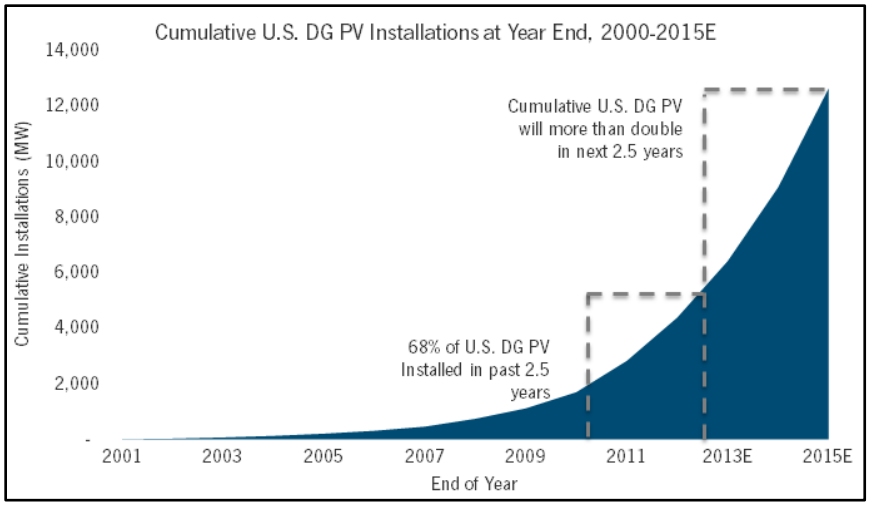
While utility-scale wind and solar power receive most of the attention in grid planning forums, distributed generation also is growing in size and use. Several factors are responsible for this growth, including federal tax incentives and complementary federal and state public policies, such as the Commission's *pro forma* interconnection procedures, similar state interconnection

---

[5] ACEEE, *State Energy Efficiency Resource Standards* (July 2013), available at http://aceee.org/files/pdf/policy-brief/eers-07-2013.pdf.

[6] *See* Appliance Standards Awareness Project, *The Efficiency Boom: Cashing in on the Savings from Appliance Standards* (2012) (available at http://www.appliance-standards.org/documents/reports/efficiency-boom-cashing-savings-appliance-standards). Notably, under normal evaluation protocols, EEPS energy savings should not double-count the effects of the appliance standards. The new appliance standards typically become the new "baseline" against which EEPS program effects are calculated.

rules, retail net metering billing rules, carve-outs for distributed generation in state RPSs and customer demand. Solar power installations in particular are increasing rapidly:[7]



In combination with economies of scale and other factors, the prices of solar PV installations continue to fall to more competitive levels.[8]

D. <u>Other Drivers</u>

A plethora of other technological and policy changes also affect grid planning and operations. Energy storage technologies are scaling up to commercial size. State-regulated dynamic pricing programs are becoming more popular, and some RTOs have created rules to allow price-responsive demand programs to participate in wholesale energy and capacity markets. The U.S. EPA's mercury and air toxics standards (MATS) and low natural gas prices are making many gigawatts of fossil fuel power plants uneconomic. Finally – and this has not

[7] Source: GTM Research (2013), used with permission.

[8] Year-over-year, the average national price of a PV system has dropped 24%, to $3.37/watt. *See* Solar Energy Industries Association, *Solar Energy Facts, Q1 2013* (available at http://www.seia.org/sites/default/files/Q1%202013%20SMI%20Fact%20Sheetv3.pdf).

received sufficient attention in all RTOs -- state-regulated resource planning requirements often constitute PPRs which should be accounted for in RTO/ISO planning and markets.

III. Current Capacity Markets – Barriers and Opportunities

Capacity markets traditionally have been designed to meet system resource adequacy needs. Resource adequacy typically refers to the total quantity of resources needed to meet peak load demand on the highest load days (usually summer days). Based on resource adequacy requirements to meet loads on peak days, RTOs and ISOs have evaluated resources in each of their regions on their ability to provide energy over a relatively small number of hours in order to establish their individual capacity value.

New variable energy resources such as wind and solar have their capacity values set by their availability during the peak hours on hot summer days.[9] Similarly, energy efficiency resources have their capacity values set by their availability over a limited number of summer hours. Demand response resources typically are required to be available for short periods of time during summer days with high loads, but both PJM and New England have implemented rule changes that expand the required hours of availability for certain demand response products. Because all resources had have had their capacity values set by their availability to provide essentially the same service during the same limited number of peak hours, the payment to these different resources would be on the same basis.

Grid planners increasingly recognize that resource adequacy is just one element of overall system reliability. To meet other reliability needs, some system operators are expanding the requirements and eligibility criteria for capacity resources. Whether current capacity markets, with their focus on meeting peak demand, are the appropriate mechanism to address these other

[9] New England also includes a winter availability requirement based on the peak hours on cold winter days.

reliability needs is open to serious question. At a minimum, current capacity markets may require flexibility mechanisms to broaden their focus. Where markets do not exist now, other market designs, such as flexibility or operating reserve markets, may offer more reliable and cost-effective solutions, especially in assuring integration of renewable energy, energy efficiency and distributed energy resources into the electric grid.

We highlight below some of the ways in which current capacity markets either support or frustrate these changes.

A. Minimum Offer Price Rule – Impact on Renewable Energy Resources

Application of a minimum offer price rule ("MOPR") to state-incented clean energy resources unfairly reduces their capacity value and costs consumers money. The primary purpose of a MOPR is to prevent buyers of capacity from suppressing capacity prices by subsidizing higher-cost new capacity to replace lower cost existing capacity. ISO-NE, NYISO and PJM all use the MOPR in their capacity markets, but they apply it under different circumstances and to different resources. (Whether MISO should apply a MOPR in its resource adequacy construct is a question in a pending FERC proceeding.[10]) ISO-NE applies the MOPR to most resources, including state-subsidized renewable resources, NYISO applies MOPR to all resources, but only in the New York City area,[11] and PJM applies MOPR to combustion turbines, combined cycle units and integrated gasification combined cycle units. PJM does include several exemptions to application of the MOPR to these resources.

---

[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 144 FERC ¶ 61,125 (Aug. 12, 2013) (order initiating briefing procedures).

[11] NYISO refers to the MOPR as Capacity Market Mitigation. On September 4, 2013, the NYISO Board of Directors rejected a request to apply Capacity Market Mitigation statewide, finding that there was no evidence of buyer side market power in the rest of the state. Decision available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/appeals/Appeals_to_the_BOD/June_11,_2013/Board%20Decision%20ROS%20Mitigation%20Appeal.pdf.

The Sustainable FERC Project opposes application of MOPR to most renewable energy projects created as a result of a state policy (e.g., RPS, state resource mix target). One practical effect of the MOPR can be to force wind and solar resources to offer at prices so high that they would be excluded from clearing in the auction and taking on a capacity supply obligation. Many of these wind and solar resources are built to meet RPS standards; these resources will be constructed and will provide capacity benefits whether or not they are able to clear and take on a capacity supply obligation. The RTO also will be required to purchase through the annual capacity market auction additional, unnecessary resources. These purchases will impose unnecessary costs on consumers and produce unjust and unreasonable rates.

B. Demand Response Resources

Demand response ("DR") is a valuable resource in capacity markets, providing cost savings and environmental benefits (assuming that the DR is occurring through true load reduction and not simply shifting to backup or other behind the meter generation). DR also can provide valuable ancillary services functions, including supporting integration of variable energy resources. Demand response is a particular success in PJM's capacity market, with 10% or more of total resources in PJM clearing the auction each year. Its performance is at least as good as generation resources, with its event performance in PJM exceeding 100% in 2012 (latest year for which complete data is available).

Notwithstanding DR's value, we see several storm clouds on the horizon for DR. They include:

- In PJM, an emerging proposal to cap the Limited DR[12] capacity market product.
- Also in PJM, proposals to impose significant new operational and deliverability obligations on DR resources.
- In ISO-NE, proposed performance incentive rules which could impose unfairly high penalties on DR in the capacity market.
- In MISO, the near-complete absence of DR in its first resource adequacy auction, held earlier this year, represents an under-utilized resource. We are not optimistic that more DR will bid or clear in the next annual auction.

In PJM, there is no major indication that DR has "saturated" the market yet. It has performed very well when called and tested, and PJM is in the process of creating registration and resource commitment rules to further assure performance. In other capacity markets, DR has not come close to its potential. We therefore encourage RTOs and ISOs to continue to explore ways to maximize the use of DR, whether to reduce peak demand during system emergencies, or to meet other grid needs, and to not create new barriers to its use in current markets.

C. Energy Efficiency Resources

We have encountered at least two issues with how existing capacity markets accommodate energy efficiency resources. First, not all existing resources may be bid into the markets. Second, markets may not reflect their full value.

1. All available EE resources likely are not participating in markets where opportunities exist

In PJM, energy efficiency remains a small fraction of total capacity – only 0.66% in the last PJM Base Residual Auction for the 2016/2017 delivery year. Far more energy efficiency resources likely exist in the PJM region than are bidding into the auction. Many of these

[12] PJM's Limited DR product applies to DR with the ability to commit to 10 emergency events during the summer for at least 6 hours during each event.

resources are under the control of load-serving entities or affiliates pursuant to state energy efficiency resource standards.

PJM's May 2012 PJM auction, for the 2015/2016 delivery year, offers a good example of the potential size of the missing EE. In Ohio, a study by ACEEE and the Ohio Manufacturers Association found that more than twice as much EE was eligible for the auction as was bid into the auction.[13] Considering that the majority of customer load in PJM is subject to energy efficiency resource standards, a significant amount of EE likely is eligible for but is not bidding into the auction.

The solutions to this problem involve both RTO and state actions. PJM and other RTOs should take the necessary steps to assure that all EE expected to be available for the relevant auction year and under the control of an LSE or affiliate actually is bidding into the auction.[14] Absent unreasonable rules and other barriers, failure to bid such EE *could* be construed as an exertion of market power. This question deserves more Commission attention. On the states' side, regulators may need to require participation in auctions as a condition of a utility's EE implementation plan. For example, in March 2013, the Public Utilities Commission of Ohio ordered First Energy to bid at least 75% of the savings of energy efficiency programs it plans to run into the PJM Base Residual auction for the 2016/2017 planning year.[15] This order had the positive result that EE clearing the PJM auction in the FirstEnergy region increased from 36 MW to 197 MW in one year.

---

[13] 269 MW of EE were bid into the auction, 265 MW cleared, and the study found that an additional 508 MW were eligible. See ACEEE, *Ohio's Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State*, at Appendix A, p. 34 (available at www.ohiomfg.com/legacy/communities/energy/OMA-ACEEE_Study_Ohio_Energy_Efficiency_Standard.pdf).

[14] NYISO does not currently allow EE resources to participate in its capacity market.

[15] Public Utilities Commission of Ohio, Opinion and Order in Case No. 12-2190-EL-POR, pages 20-21 (March 20, 2013) (available at http://elpc.org/wp-content/uploads/2013/03/12-2190-order.pdf).

2. Pay new EE resources for their measure life

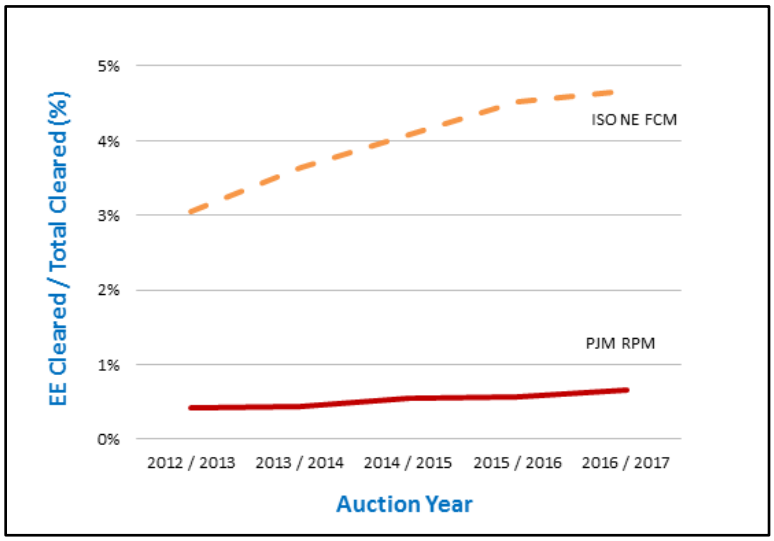
To qualify for participation in a capacity market auction, EE resources need to demonstrate that they can provide the capacity services that are needed. PJM and ISO-NE account for the energy value of EE resources in different ways, with PJM's approach not fully reflecting the value of the resource, while ISO-NE recognizes the full EE measure life in capacity payments.[16] From a rate perspective, failing to recognize the verifiable life of an EE measure in a capacity market payment could be unjust and discriminatory.

PJM limits the payment to EE resources to a maximum of four years, because PJM modifies its load estimates, and therefore the target quantity of resources purchased in its annual capacity auction, by using the meter reads after the installation of the EE measures. (If PJM continued to pay the EE resources after it reduced its load forecast for the annual capacity auction, the EE measures would be double-counted.) EE resources receive payments for only four years; the remaining years of measure life are credited to consumers, who benefit after the first four years by not having to purchase the EE resources. This approach assumes that PJM is fully and accurately crediting the remaining EE measure life through its meter reads, an assumption that is difficult to verify given the many factors that affect annual meter reads (e.g., weather, time of day, changes to consumption).

ISO-NE, in contrast, provides payment to EE resources for their measure life, because ISO-NE uses an unadjusted load forecast, not reduced by the lower loads measured after EE installation, for setting the quantity of capacity resources purchased each year. EE resources receive payments for more years because they continue to be purchased for their entire measure

[16] "Measure life" refers to the predicted duration of the efficiency measure, primarily taking into account both the estimated equipment life and reasons why the measure might be discontinued or removed prior to the end of the equipment life.

life. Based on the results of capacity auctions in both PJM and New England, this payment for measure life has stimulated significantly more EE resources to participate in the New England capacity auctions than in the PJM capacity auctions:[17]



D. Distributed Generation

Small scale resources, such as energy efficiency, solar and combined heat and power may also be barred from capacity market participation because of their smaller size, onerous qualification procedures, and potential penalties for failure to perform in non-peak hours. For example, an air conditioner EE resource may be penalized for not performing during the winter months. Another example is a PV solar resource that is penalized, or even disqualified, because it cannot provide energy at night. Yet both of these resources can provide meaningful contributions to summer peak loads.

A good example of the lack of visibility in capacity markets is in ISO New England, where the current Board-approved Regional System Plan, the planning document for needs assessments and transmission upgrades, estimates that there will be 800 MW of PV solar in New England by

[17] Source: Synapse Energy Economics (2013).

2020.[18] However, a recent detailed study showed that there will be over 800 MW in place in the region by the end of this year and that by 2020 New England may have 3000 MW of net-metered distributed generation (mostly PV solar).[19] Next spring, ISO-NE will be purchasing capacity resources for the 2017-2018 delivery year, and the target quantity to be purchased will reflect almost none of these distributed resources. Over-purchasing of other resources without recognizing the value of these resources could result in unjust and unreasonably high capacity payments.

E. Uneconomic Older Generation

We have concerns with capacity markets continuing to subsidize older, inefficient and uneconomic units, which can reduce the number of newer, cleaner units clearing in an auction. For example, in New York the 1800 MW Oswego facility regularly clears the NYISO capacity market and collects capacity market revenues while operating on extremely low capacity factors. The plant provides very little reliability value to the NYISO system due to NYISO's high reserve margin (28%, which exceeds the 17% requirement). On the other hand, approximately 9,485 MW of coal-fired capacity (unforced) did not clear the PJM Base Residual Auction for the 2016/2017 planning year, suggesting that some combination of EPA environmental standards, low natural gas prices, capacity market rules and insufficient energy market revenues affected at least some plants' economic viability this year.[20] In the future, many of these older plants may

---

[18] ISO New England, *Solar Photovoltaics in New England* (May 2012) (available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may162012/solar_photovoltaics.pdf).

[19] *See* Synapse Energy Economics, *Forecasting Distributed Generation Resources in New England* (June 2013) (available at http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.E4-Group.DG-in-New-England.11-052.pdf.

[20] PJM, *2016/2017 Base Residual Auction Results*, at 31 (available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx).

not meet some of the flexibility-focused standards in capacity or "capabilities" markets (see Part IV below).

IV. Looking Ahead – Iterative or Systemic Changes?

Given the changing nature of the electric grid, pure capacity markets designed to meet peak load-focused goals may not be the most cost-effective and efficient mechanism to assure grid reliability. These markets traditionally have been focused on having adequate resources to meet a relatively few hours of peak loads. The resource mix of the future will require greater operational flexibility as grid operators address the variability of all resources on a daily, hourly, and minute-by-minute basis. In particular, focusing on meeting "net load for energy" will become increasingly important as variable energy resources, energy efficiency and distributed resources increase their contributions to daily dispatch models.[21] The Regulatory Assistance Project's work on "*Beyond Capacity Markets*" provides a productive discussion on market design with a focus on meeting net demand. We support RAP's general analysis and many of its recommendations, which address several investment timescale market design ideas for flexible, performance-focused resources.[22]

In this new paradigm, fast-responding and cleaner dispatchable resources such as demand response and natural gas plants will become increasingly valuable, as will storage. A principal design assumption of most current capacity markets is that all resources provide the "same service." That is not true today, and will become more obviously untrue in the near future. With

---

[21] For example, by 2015, the California ISO's mid-day peak load will be almost 8 GW less than currently, due to displacement by solar power plants. See CAISO, Flexible Resource Adequacy Criteria and Must-Offer Obligation (Dec. 2012), at 8 (available at http://www.caiso.com/Documents/StrawProposal%E2%80%93FlexibleResourceAdequacyCriteriaMustOfferObligation.pdf).

[22] See http://www.raponline.org/featured-work/beyond-capacity-markets-delivering-capability-resources-to-europes-decarbonised-power.

these considerations in mind, we recommend that the Commission take into account the following priorities as it evaluates future capacity market design choices.

A. Prioritize More Flexible Resources

Given the significant expansion of renewable and distributed resources, and other factors discussed above, flexibility will assume increasing importance as a resource and reliability value in every wholesale market region. Whether the procurement of these resources occurs through capacity markets or more specialized markets will depend on the region and whether current market structures can accommodate these new considerations and requirements. In some cases, existing capacity market rules may be modified with flexibility enhancements. ISO New England's FCM Performance Incentives initiative is an example of iterating an existing capacity market to improve resource performance and availability. As the Regulatory Assistance Project has explained in its *Beyond Capacity Markets* work,[23] more sweeping changes could include creation of an apportioned capacity market to meet net energy demand (gross demand less the contribution of variable renewable energy resources). In this construct, the capacity market would be subdivided into tranches, with the most flexible (short-cycling) firm resources placed in the first procurement tranche, with the least flexible resources last. Payments would be based on a combination of the market value of firm capacity and flexibility and other reliability attributes.

In other cases or regions, a forward services market may be sufficient to obtain the resources necessary for reliability without saddling consumers with excessive and potentially unnecessary capacity costs. In this market design, auctions or another mechanism would procure resources for

[23] *Id.*

a variety of ancillary services. Energy storage and qualified demand side resources would be eligible to participate. These markets would fill a specific reliability gap.

MISO offers a good example of how a flexibility component could be added either to its existing resource adequacy market or as a new forward services construct. MISO does not have an especially active or lucrative capacity market, since most resources are committed under state resource adequacy plans and owned by utilities. MISO also has a significant amount of renewable energy generation in its footprint. Over time, increasing variable energy generation could drive the need for more flexibility resources. While most states in MISO have RPS laws that are driving renewable energy development, these states, acting individually, may not be in the best position to efficiently induce the development flexibility resources for the regional. MISO, as the regional grid operator and system planner, may be better suited to establish a regional flexibility or forward services market.

Regardless of whether these design changes occur incrementally to existing markets or as new markets, the Commission and wholesale market planners should take certain design considerations into account.

First, in valuing the flexible capacity of a resource, operational characteristics for a "flexible" resource should be defined to allow for meaningful participation by low carbon resources such as energy storage and demand response. For example, in response to a projected increased need in flexible capacity due to higher renewables penetration, the California Public Utilities Commission (“CPUC”) examined proposed enhancements to its resource adequacy program to require flexible capacity procurement to ensure the operational availability of resources that could provide 3-hour ramping capability to meet ramping needs as the sun sets and solar output declines. Although the flexibility need was for a predictable late afternoon/early evening ramp,

the original proposal by the California Independent System Operator and two California utilities required a resource to be available for a 17-hour dispatch period to qualify for flexible capacity procurement, effectively limiting participation to natural gas. The CPUC subsequently adopted a less restrictive definition of flexible capacity for hydro resources and is currently working on adopting definitions for flexible capacity that recognize the operational limitations of energy storage and demand response resources.[24]

Second, market designers should consider the conditions under which variable and non-variable resources can combine together as hybrid capacity resources with a flexibility component. For example, in ISO New England, the market rules do not easily allow for submission of combined units of different types as a single resource. Variable resources have significant capacity value, and as a combination resource (for example wind and combined cycle or hydro units), they could add more cost-effective value to the system than each could alone.

Third, resource use and access should be encouraged across regions. Access to larger pools of supply and demand resources improves reliability and flexibility and reduces variable energy integration costs. In an analogous context, PJM recently reported that, due largely to its nearly doubling in size in the last decade, the need for synchronized reserve calls has decreased from once every three days to once every 12 days. Given the additional resources under PJM's economic dispatch, and that the largest single unit contingency has increased only from 1150 MW to 1300 MW, PJM now has more resources that can respond economically to a unit loss.[25]

---

[24] California Public Utilities Commission, Decision 13-06-024, *Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program* (July 3, 2013)(available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF). Also, depending on the rules, even natural gas units can be disadvantaged. For example, a cold start assumption would give less capacity value to a combined cycle unit than a warm start.

[25] Source: PJM presentation at Aug. 29, 2013 Markets and Reliability Committee; communications with PJM staff.

B. Fully Account for Energy Efficiency Resources

As noted above, energy efficiency is often the most cost-effective energy resource, and it can be a viable solution for both distribution and transmission system needs. All markets should include the following priorities:

First, markets should recognize the full measure life of energy efficiency resources. Many EE resources are likely to be driven by state energy efficiency resource standards. However, regardless of the driver, accounting for anything less than the full, verified measure life is unjust and discriminatory. Most efficiency investments are customer funded, so failing to provide the opportunity for them to recover capacity revenues denies consumers a fair return on their investments and improves the economics of the resource. The result is more energy savings per dollar of public investment.

Second, market design should include examination of other barriers to full participation of energy efficiency in existing markets. As explained above, some eligible EE in PJM likely is not bidding into the market. The comparatively low levels in PJM may be attributable to uncertainty over whether utilities are required to bid EE under their control into the market, complex measurement and verification rules (which may be inconsistent with a state's implementation rules for efficiency standards), or other reasons.

Finally, regions should ensure that load forecasts completely account for energy efficiency which is not reflected in capacity market bids. The work of ISO New England in creating an Energy-Efficiency Forecast Working Group to more accurately measure and forecast all energy efficiency in its region is a good model for other RTOs to consider.

C. Accommodate State Public Policy Priorities

A continuing question with current centralized capacity markets is the extent to which they may conflict with or duplicate state resource adequacy actions and policy priorities. Conflict or duplication can occur very broadly, such as the issue of whether the state resource planning in most of the MISO states obviates the need for a long-term, all-resource market. It also occurs in more specific circumstances, such as in whether a MOPR should be applied to state-sponsored, public power and other resources. Not surprisingly, these conflicts generally are less likely to occur in the single state ISOs of California and New York, where state/ISO coordination can occur without experiencing interstate conflict over resource or policy priorities.

Our view is that regardless of whether a wholesale market operates in a single state or across a region, the market should focus on clearly-demonstrated needs and avoid undermining state energy commitments or causing unintended consequences. Wholesale markets and products may fill important reliability gaps and facilitate the rapidly increasing penetration of variable energy resources that the states, acting individually, are unable to meet. A related need is to account for state-regulated, distribution-level resources to meet localized capacity needs. Also, in considering state priorities and needs, forward capacity and related market design should avoid applying the MOPR and related rules to state-sponsored, public power and other resources where the intent to exercise market power is unlikely to occur. Application of MOPR to these resources can result in the acquisition of unnecessary capacity and denies these resources capacity market revenue.

CONCLUSION

The Sustainable FERC Project appreciates the opportunity to provide its comments to the Commission on this important topic. State and federal environmental and clean energy policies,

in combination with new technologies and declining costs for existing technologies, are creating fundamental structural changes in how grid planners design and operate the electric grid. Within the next generation, renewable energy and energy efficiency will be dominant in many areas of the country. Grid operators should develop and use targeted tools to assure grid reliability, which we define to include the cost-effective integration of these new resources into the grid. Longer-term, investment-scale markets may have a role in achieving this goal, although the precise solution will depend on the region of the country and the RTO or ISO in question. We encourage the Commission to continue to solicit stakeholder input on potential systemic changes to capacity and successor markets, even as the Commission reviews ongoing RTO and ISO proposals for incremental changes to existing markets.

Respectfully submitted,

John N. Moore
Senior Attorney, Sustainable FERC Project
20 North Wacker Drive, Suite 1600
Chicago, Illinois 60606
(312) 651-7927
moore.fercproject@gmail.com

Dated: September 9, 2013