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VIA EFILING

June 13, 2023

Kimberly D. Bose, Esq.
Secretary
Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *PJM Capacity Market Forum*, Docket No. AD23-7-000

Dear Secretary Bose:

I appreciate the opportunity to participate in the discussion of the PJM capacity market design at the Commission-led forum scheduled to convene in this matter on Thursday, June 15, 2023. The IMM is actively participating in the PJM stakeholder process addressing capacity market issues. I have attached a memo that explains the Sustainable Capacity Market design (SCM), the IMM proposal for capacity market design in the PJM stakeholder process.

Sincerely,

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DATE: **June 13, 2023**
TO: **RASTF/CIFP**
FROM: **IMM**
SUBJECT: **Capacity market design proposal: Sustainable Capacity Market (SCM)**

This memo presents the Sustainable Capacity Market design (SCM), the IMM proposal for capacity market design.[1]

No proposal to change the capacity market design can solve all the issues in the capacity market or all the issues that affect the operation of the capacity market. The SCM proposal is designed to address several key issues in the capacity market design in an incremental approach, building on the basic RPM design.

Key Elements of SCM Proposal for Capacity Market Design

1. Capacity offered in the forward capacity market, ACAP (available capacity), is (ICAP * MEAF), where MEAF is the modified equivalent availability factor.
2. Capacity is paid in the delivery year only when available to produce energy, by hour. (Hourly price = annual capacity market clearing price/8,760)
3. Capacity market prices are single annual clearing prices by constrained LDAs determined per existing market rules defining LDA constraints.
4. Must offer requirement in the capacity market applies to all existing capacity resources.
5. Must offer requirement in the energy market means that all committed capacity resources must offer all capacity at ICAP MW in a combination of the energy, ancillary services and reserve markets.
6. Capacity resources that require fuel must have firm fuel in the form of dual fuel capability with a defined number of days of onsite stored fuel, or multiple pipelines with firm transportation and a firm commodity supply.
7. Capacity resources must be subject to weekly testing on a schedule determined by PJM that would include the results of economic operations.

SCM Proposal

The SCM proposal for the capacity market is a return to basics. The capacity performance capacity market design deviated significantly from the purpose of the capacity market. The only purpose of the capacity market is to make the energy market work. That means two specific things. The capacity market needs to define the total MWh of energy that are needed to reliably serve load, calculated as the peak loads plus a reserve margin. This is the reliability analysis, which needs to be hourly and to incorporate generation and transmission availability

[1] This memo expands on and extends the details of the IMM proposal in the RASTF for capacity market design presented in the memo of February 10, 2023, with the subject line "High level capacity market design proposal."

and outages on a realistic basis (recognizing observed availability and correlations among outages). The capacity market needs to provide the missing money. The capacity market needs to allow all capacity resources the opportunity to cover their net avoidable costs to ensure the economic sustainability of the reliable energy market. The fundamentals of the capacity market design (RPM) introduced in 2007 were consistent with this approach, although there were clearly flaws in the details of the design including incentive issues.

Capacity does not provide reliability. A supply of available energy greater than demand provides reliability. Capacity is not more valuable on some days or in some hours than others. The PJM capacity market design has paid all capacity resources exactly the same price per MW of UCAP in every hour since its inception in 2007. Energy is more valuable on some days and in some hours and that value equals the LMP in those hours resulting from the operation of the energy market and the ancillary services markets plus the price in the reserve markets. Using net avoidable cost as a metric, capacity is actually less valuable in high demand hours when energy prices are high. In high demand hours energy market net revenues are high and therefore net hourly avoidable costs are low or, more likely, negative. If energy market prices were high enough to cover the gross avoidable cost of capacity resources on an annual basis, and expected to remain high enough, the appropriate price of capacity would be zero. Although those conditions are unlikely to persist, that is the underlying concept of an all energy market.

The idea that capacity is always more valuable during one or five peak hours derives from the history of cost of service allocation issues in rate cases in the regulatory paradigm, and not from the operation of markets. In the cost of service world, the allocation of capacity costs determined the rates paid by different customer classes and cost of service studies became exercises in how to allocate costs to the other customer classes. But the fact that the costs of a base load plant could be allocated to a single peak hour did not mean, to anyone, that the baseload unit was expected to operate only for that one hour and did not mean that the baseload unit was built to serve load for that one hour. As has become clear during the discussions of ELCC calculations in the PJM stakeholder process, the MW capacity value of a resource requires that the resource produce energy equal to its ICAP whenever it can, in the case of an intermittent resource, and whenever it is economic, or called on by PJM, in the case of a thermal resource. The obligation of a capacity resource, whether intermittent or thermal, is to be available to provide as much energy as possible and to operate when called on. That is the essential link between the energy and capacity markets.

Capacity is not a thing. Capacity does not power light bulbs or refrigerators or air conditioners. The only real product provided in wholesale power markets is energy. Capacity is a concept designed to make the energy market work. The concept of capacity is needed in the overall market design, given the requirement that the system must include a reserve margin and therefore that the energy market will almost always be long and therefore that revenues from the energy market will not support a self sustaining overall market design.

Paying resources only when they are available provides an important incentive to perform at all times. Paying resources only when they are available is a long term, predictable incentive for performance. This incentive structure is quite different than the existing PAI incentive structure which relies on potentially massive penalties from unpredictable and not clearly defined PJM actions based on perceived market conditions. Relying on high impact, low probability events as the basic performance incentive in the capacity market is not an effective incentive structure. Relying instead on a long term, predictable incentive provides an ongoing, measurable incentive to ensure that resources have maximum availability, including availability during high stress hours.

There is no reason to believe that fear of high impact, low probability events provides an effective incentive to make long term investments in improving the availability of capacity resources. The evidence from Elliott does not support the use of the high impact, low probability incentive structure. If the capacity market revenue depends on investing in making generators more reliable in every hour, the units are more likely to be available at times of high stress. Capacity market revenue is essential to the economic viability of capacity resources in PJM. Linking payment of those revenues to hourly performance is a strong incentive to invest in reliability.

Availability

Average Availability in the Forward Capacity Market Auctions

The metric for whether a capacity resource is meeting its obligation is its availability to generate energy. The reasons for the lack of availability do not matter. A capacity resource is either available to generate energy or it is not. It does not matter if the resource does not have fuel for any reason. It is not available. It does not matter if the resource is on a six month planned outage. It is not available. It does not matter if the resource is not repairable but is on a lengthy forced outage. It is not available. It does not matter if the sun is not shining, or it is the middle of the night, and the solar resource cannot produce. It is not available. It does not matter if the wind is not blowing and the wind resource cannot produce. It is not available. It does not matter if the temperature is high and the gas fired thermal resource cannot meet its full ICAP. It is not available. In all those cases, the energy from the capacity is not available or is only partially available. In all those cases, the capacity resource is not meeting its obligation to be available to generate energy. In all those cases the capacity resource would not be paid when it is not available. This is not a penalty. This is payment for performance. No one expects solar resources to be available in the middle of the night. Solar resources do not have a performance obligation in the middle of the night and solar resources will not be paid for capacity in the middle of the night.

Currently defined performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EAF equals (1 – EMOF – EPOF – EFOF). The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

While the EAF is not the exact availability metric that should be used in the capacity market, the concept of availability is the right concept. The formal definition of availability needs to be expanded to include other reasons for thermal nonavailability, and to include the availability of intermittent, storage and demand side resources. This new, inclusive definition of availability is termed the modified equivalent availability factor (MEAF). The MEAF includes the three elements of the EAF plus ambient derates for thermal resources and derates for environmental limits and derates for all other reasons. The historical MEAF for intermittent resources is measured as the actual historical capacity factor. The historical capacity factor for intermittent resources incorporates all reasons for nonavailability including ambient conditions and outages of all types. The historical MEAF for intermittent resources could be understated to the extent that actual output was reduced as a result of PJM dispatch instructions.

The current capacity market design defines the capacity available to be sold based solely on ICAP and the forced outage rate (EFORd). EFORd is also not as comprehensive a metric of availability as the proposed MEAF. EFORd focuses solely on forced outages, which creates incentives to not classify outages correctly. But the classification of the outage does not matter to the energy market. If a unit is unavailable, it is unavailable. MEAF is a more comprehensive and more accurate measure of availability.

The analog of UCAP in this design is available capacity (ACAP). The average hourly ACAP that a resource can sell in the forward capacity market equals (MEAF * ICAP). The capacity offer price for a capacity resource equals net ACR divided by ACAP. Like EFORd currently, MEAF for the forward market would be based on the prior 12 months of historical data.

Hourly Availability in the Forward Capacity Market Auctions

While availability is a key metric, even a correctly defined annual availability metric does not address hourly availability or comparability among resources. For example, a solar resource that is 45 percent available will never be available in the middle of the night while a thermal resource could be available in any hour of the year, subject to outages and derates.

The solution is to clear the annual capacity market, accounting for the expected availability of resources on an hourly basis. The hourly availability of capacity to produce energy is HACAP MW (hourly available capacity MW). Accounting for expected hourly availability is required in order to address the first purpose of the capacity market which is to procure enough capacity to ensure that energy will be available to reliably serve load in every hour. The purpose of accounting for hourly availability is not to set an hourly price for capacity but to ensure that the system will be reliable in every hour based on expected demand and expected availability of resources to provide energy to reliably meet the demand. The capacity product is still an annual product, but both demand and supply vary by hour. In the middle of the night, solar resources are not included in the supply curve. In the middle of a summer day, solar resources are included in the supply curve. The demand for energy is lower in the middle of the night than in the middle of a summer or winter day.

The purpose of accounting for hourly availability is to help ensure that the capacity market matches the expected availability of resources to generate energy with the expected demand for energy on an hourly basis. Reliability on an average annual or seasonal basis is not reliability. Accounting for hourly availability on a locational and resource specific basis more accurately defines availability than offering capacity based on derating by a simple class average, non locational availability factor, e.g. PJM's use of technology class ELCC availability factors for all hours and for the entire PJM market. The hourly approach also incorporates the essential locational characteristics of the capacity market by recognizing availability on a resource specific basis.

The defined market clearing process results in a single annual clearing price for each constrained LDA based on the marginal resources and using the existing CETO/CETL rules. Appendix 1 presents the mathematical logic of the clearing process and an example of how the market clearing process would work.

Hourly Availability in the Delivery Year

The current capacity market design pays capacity resources the same hourly capacity price every hour of the year, regardless of availability. That design does not provide appropriate incentives to be available.

Rather than penalizing capacity resources for nonperformance at extreme and arbitrary penalty values only during emergencies (defined PAI events), capacity resources should be paid the hourly price of capacity only to the extent that they are available during the operating day to produce energy or provide reserves, as required by PJM on an hourly basis, up to the full ICAP value of their cleared capacity. This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. In the CP model, the combination of B and UCAP means that resources are obligated to provide significantly less than full ICAP. This significantly weakens the performance incentives under CP. That reduced obligation is inconsistent with the PJM market design which requires capacity resources to offer energy equal to 100 percent of ICAP every day in the energy market. For example, with a B of 0.80 and an EFORd of 0.95, the required performance would be only 76 percent of ICAP. With an EFORd of 0.50, the obligation would be only 40 percent of ICAP. This positive incentive approach would also end the need for complex CPQR calculations based on an unsupported penalty rate and assumptions about the number and timing of PAI.

The obligations of committed capacity resources currently include the requirement to offer their full available ICAP in the day-ahead energy market every hour of every day and to produce as much energy as they are capable of producing when economic or are dispatched by PJM. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year.

Paying resources only when they are available provides an important incentive to perform at all times. Paying resources only when they are available is a long term, predictable incentive for performance. This incentive structure is quite different than the existing PAI incentive structure which relies on potentially massive penalties from unpredictable and not clearly defined PJM actions based on perceived market conditions. Relying on high impact, low probability events as the basic performance incentive in the capacity market is not an effective incentive structure. Relying instead on a long term, predictable incentive provides an ongoing, measurable incentive to ensure that resources have maximum availability, including availability during high stress hours.

There is no reason to believe that fear of high impact, low probability events provides an effective incentive to make long term investments in improving the availability of capacity resources. The evidence from Elliott does not support the use of the high impact, low probability incentive structure. If the capacity market revenue depends on investing in making generators more reliable in every hour, the units are more likely to be available at times of high stress. Capacity market revenue is essential to the economic viability of capacity resources in PJM. Linking payment of those revenues to hourly performance is a strong incentive to invest in reliability.

The historical switch from reliance on cost of service regulation to wholesale power markets improved generator capacity factors based on the long term, predictable incentives from market prices. The market incentives did not rely on high impact, low probability events as an essential incentive.

The important difference between the SCM proposed design and the current CP design is that under the proposed design, capacity resources are not paid the hourly capacity price when the resources are not available in an hour. Under the current design, capacity resources are paid the same hourly capacity price in every hour even when resources are on long term planned outages, when resources are on maintenance outages, when resources are on forced outages and when thermal or intermittent resources are not capable of producing energy equal to ICAP as a result of ambient conditions.

The hourly approach is a natural evolution in the capacity market design, given the increased heterogeneity of resources. The hourly approach is essential in light of the growing role of intermittent resources which, unlike thermal resources, are not available in every hour.[2] The hourly approach provides a flexible way for demand resources to participate on the supply side or the demand side. The hourly approach also provides appropriate performance incentives to thermal resources by rewarding resources that are available and reducing payments to those that are not available. The hourly approach also explicitly recognizes that a small number of summer hours are not the only focus of reliability. PJM is increasingly recognizing that there can be reliability issues in the winter. The hourly model does not depend on identifying the days or season in advance.[3] The market results reflect the hourly demand and the hourly availability of supply. The hourly approach is clearly preferable to PJM's application of ELCC because the hourly approach pays resources only when available. While ELCC is initially based on hourly data, ELCC applies flat derating factors by broad technology classes that do not vary by hour or by location. In Elliott, that approach resulted in the assessment of penalties to solar resources for not producing in the middle of the night, a clearly illogical result. Paying for performance is not possible when using only a simple average annual capacity market payment approach.

The proposed hourly approach does not represent the end point of the evolution of the capacity market design. But it is an essential step forward. The proposed hourly approach does not address all the existing and expected issues in the capacity market design. But it is an essential step forward.

The payment of the same average hourly capacity price is exactly the same as the payment for capacity in the current PJM design. PJM's current market design pays a single clearing price for the entire year, which is identical to paying every resource the same price in every hour. PJM's current design pays the same hourly price every hour even if a resource is unavailable. The

2 See "Update on Reliability Risk Modeling," presented at May 30, 2023 meeting of Critical Issue Fast Path - Resource Adequacy State 2. <https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230530/20230530-item-03---reliability-risk-modeling.ashx>.

3 See "PJM Capacity Market Fuel Assurance Accreditation Concept," presented at June 1, 2023 meeting of Critical Issue Fast Path - Resource Adequacy State 2. <https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230601/20230601-item-05a---pjm-fuel-security-proposal-concept--cifp.ashx>.

SCM proposal pays the hourly price only when resources are available. The SCM proposal provides a stronger incentive to perform.

PJM's current deficiency penalty would remain. The deficiency penalty is defined as the weighted average clearing price plus the greater of 20 percent or $20 per MW-day. Under the current rules, a deficiency exists when a unit is unable to satisfy its capacity commitment, for example as a result of unit deratings or EFORd increases prior to the delivery year, and replacement capacity was not purchased prior to the delivery day.

Market Clearing

Appendix 1 presents the mathematical logic of the clearing process and an example of how the market clearing process would work. Significant parts of the basic capacity market clearing process would remain unchanged. As in the current design, the capacity market will clear three years in advance of the delivery year. As a result, and as in the current design, the inputs to the auction are informed estimates. Just as the current design relies on historical forced outage rates (EFORd), the proposed design relies on historical modified equivalent availability factors (MEAF). Resources offer their ACAP which equals ICAP * MEAF. MEAF is the modified equivalent availability factor. The market clearing process does not use the MEAF to define the expected hourly availability of resources. The market clearing process uses the expected hourly availability (HACAP) that in aggregate results in the annual MEAF. For example, the annual MEAF of a solar resource could be 55 percent while the solar resource is not available at 2:00 AM and is 100 percent available at 2:00 PM. The hourly availability of resources is a function of the expected hourly distribution of ambient derates, derates for any reason, and planned, maintenance and forced outages. The hourly availability of resources is largely a function of the hourly distribution of solar radiance and wind speed for intermittent resources. PJM will optimize the distribution of planned outages and maintenance outages to hours by unit. Forced outages will be assigned based on history. The availability of intermittent resources will be assigned based on history.

Offer prices will be the marginal cost of capacity, net ACR, subject to the existing rules on the MSOC, including the current definition of CPQR. Offer prices will be on a dollar per MW of ACAP basis with expected HACAP MW for each hour in the delivery year, where ACAP is ICAP * MEAF.

The historical availability of intermittent resources is the basis for the expected hourly distribution of availability in the forward capacity market clearing process. The capacity market clearing process must also recognize that the availability is a point on a distribution of possible outcomes for each resource, and that the distribution of outcomes are not independent. The clearing process must recognize this distribution.

The demand for capacity in each hour is a function of PJM load forecasts plus a reserve margin. The model can work with any metric for reliability, including expected unserved energy (EUE) or the loss of load expectation (LOLE) or loss of load hours (LOLH).

The market clearing is an optimization with the objective function of minimizing the costs of meeting the hourly demand for the entire delivery year.

The highest cost resource required to meet the demand in any hour will set the annual clearing price. All cleared resources will receive the annual clearing price on a dollar per MW of ACAP basis. Customers will pay the total actual cost of capacity, reflecting the annual clearing price and the hourly availability of each resource, with locational accuracy.

The clearing process will result in locational prices as a function of locational supply and demand fundamentals, including the existing approach to CETO/CETL values. Under the proposed approach, the CETO/CETL and local demand will explicitly and correctly recognize the resources that will offer into the auction and their locational characteristics, including expected locational availability. The clearing process works with the existing definitions of LDAs.

In the delivery year, resources are paid for capacity on an hourly basis if they are available and not paid for capacity if they are not available. The proposed settlement is hourly and based on hourly available MW multiplied by the annual capacity market clearing price ($/MW-year in ACAP terms) divided by 8,760 (the number of hours in a year).

In the delivery year, a resource will receive at least its annual net ACR if it performs consistent with its expected annual availability. If a resource is more available than expected, it will receive more than its net ACR and if a resource is less available than expected, it will receive less than its net ACR.

Must Offer Requirement in the Capacity Market

All capacity resources have a must offer requirement, including thermal, intermittent, storage and demand resources.

Prior to the implementation of the capacity performance design, all existing capacity resources, except DR and EE, were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The same logic should be applied to intermittent and storage resources. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand side resources remains high. The failure to apply the must offer requirement consistently could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

It is not clear why intermittents and storage were excused to date, but as the role of intermittents and storage grows it is essential to reestablish the must offer obligation for all resources.

Must Offer Requirement in the Energy, Ancillary Services and Reserve Markets

All cleared capacity resources have a must offer requirement in the energy, ancillary services and reserve markets equal to committed ICAP. This is the essential link between the energy market and the capacity market. There is no reason to have a capacity market without this requirement. The capacity market has included balanced must buy and must sell obligations from its inception.

Demand Response

Demand response resources have also been treated very differently from other capacity resources since the beginning of the PJM Capacity Market. Demand response resources do not have a must offer requirement in the capacity market, do not have a must offer obligation in the energy market, are not subject to market power mitigation rules in the capacity market, are not subject to market power mitigation rules in the energy market, and have a strike price more than twice as high as the offer cap for energy offers from other resources. There is no reason for this discriminatory treatment to persist.

Demand response resources should be treated like other capacity resources, regardless of the other features of the capacity market designs. Demand response resources have been treated differently than other capacity resources as a result of a basic confusion about whether demand response is a supply side resource or a demand side resource. Demand response resources have been treated as a supply side resource in the PJM Capacity Market but the rules about demand side participation on the supply side have followed a demand side logic. The essence of the demand side logic is avoiding payment for capacity by reducing demand. Prior to the introduction of the PJM markets in 1999, customers routinely avoided paying for capacity by curtailing their usage during the hours that determined the obligation to pay for capacity. That behavioral model was retained but demand resources were treated as supply side resources. The two models do not fit well together. Both can be a reasonable element of a capacity market design but the expectations under each model need to be clarified in order for the capacity market to be efficient and to meet its goals.

Retaining a demand side model for demand resources is one approach. Demand side resources could avoid paying for capacity by reducing demand below the level of capacity paid for (PLC) when requested by PJM. Improved and more efficient processes could be developed to provide information to customers about when to reduce demand, and to reduce individual customer payments for capacity in close to real time based on metered usage.

Defining a supply side model for demand resources is another approach. If demand resources are going to be supply side resources there should be a must offer requirement in the capacity market, a must offer requirement in the energy market, elimination of strike prices, a definition of cost-based capacity offers, a definition of cost-based energy offers, and a definition of the MW offered. The MW offered should be a guaranteed MW reduction from the PLC (level of capacity paid for) when called. The response would be based on metered data. Demand resources could offer limited hourly availability based on the physical reality of the demand side customers and based on the fact that the defined load reductions may not be available on holidays or in the middle of the night. Demand resources would be paid, like all capacity resources, based on their availability. All demand resources should be mapped to specific PJM nodes so that demand resources can be dispatched in an LMP system like all other resources.

Firm Fuel Requirement/Testing Requirement

All capacity resources must have firm fuel in the form of dual fuel with a defined number of days of onsite stored fuel, or multiple pipelines with firm transportation and a firm commodity supply. The number of required days of onsite fuel should be based on a PJM reliability analysis using data on the duration of extreme weather.

None of the requirements for firm fuel are a panacea. For example, multiple gas pipelines can have delivery issues, regardless of the firmness of the tariff service, commodity gas may be unavailable regardless of the contract, and onsite fuel can freeze. But the requirement for firm fuel would be a significant improvement on the status quo.

The exact specification of firm gas supply cannot be solved by changes to the capacity market. The issues around the definition of firm transportation and commodity gas need separate attention, regardless of the capacity market design.

The gas/electric coordination issues cannot be solved by changes to the capacity market. These issues need separate attention, regardless of the capacity market design.

There is no firm fuel requirement for intermittent resources. The availability of intermittent resources is a function of weather conditions.

All capacity resources must be subject to weekly testing on a schedule determined by PJM that would include the results of economic operations.

The experience of Elliott shows that even extreme penalties do not ensure that supply resources will obtain firm fuel. While there is a lot of work to be done in addressing coordination between the power market and the gas market, specific requirements for firm fuel and stronger requirements for testing are part of an effective and efficient solution to the issue.

Conclusion

The SCM proposed changes to the capacity market design are simple. The capacity market clearing process accounts for the expected hourly, locational availability of individual resources. In the delivery year, capacity resources are paid only when they are available.

In the forward looking capacity market clearing process that defines the resources needed to provide the target level of energy reliability, it is essential to have resource specific, locational hourly availability in order to match resource availability with the reliability objective. A simple assumption of average annual availability, or the assumption of an equivalent perfect resource at a derated MW value, will not accurately reflect actual expected availability.

In the delivery year, it is essential to pay for capacity only when it is available to produce energy. The proposed design matches payment with availability to produce energy and ensures the opportunity for all resource types to cover their net avoidable costs if their actual availability matches their expected availability. The result is to provide a long term, stable incentive for investment in maintenance and investment in new, reliable resources.

Appendix 1: Market Clearing Logic

Formulation of the Market Clearing Approach

The objective of the proposed clearing process is to maximize the surplus (area between the VRR curve and the capacity offer curve), subject to meeting the hourly reliability requirements and the hourly availability constraints.

A resource would clear if the resource is expected to be needed to meet the reliability requirement of at least one hour in the forward looking delivery period.

This is the detailed formulation of the optimization for a single LDA capacity market:

Definitions:

Sets:

s: VRR segment

h: hour

r: capacity resource

DP: Delivery Period.

Variables:

$VRR_{s,h}$: VRR segment s for hour h

$Hourly\ Capacity_{r,h}$: Capacity (HACAP MW) cleared from resource r for hour h

$Cleared\ Capacity_r$: Maximum cleared capacity (HACAP MW) from resource r for the entire delivery period

Parameters:

$VRR\ Cap_s$: Cap on VRR price (y-coordinate) in $/MW for VRR segment s

$Max\ VRR_{s,h}$: Maximum size of VRR segment s in MW for hour h

$Availability_{r,h}$: Expected available capacity (HACAP MW) from resource r for hour h

$Offer_r$: Offer price of resource r in $ per delivery year

$ICAP_r$: Installed Capacity of resource r

$MEAF_r$: Modified Equivalent Availability Factor of resource r.

$ACAP_r$: Average availability of a capacity resource, r during the delivery period, DP obtained as $MEAF_r * ICAP_r$.

Equations:

Equation 1: Objective function

The objective is to maximize the surplus (area between the VRR curve and the offer curve):

$$Max \sum_h \sum_s \frac{(VRR_{s,h} * VRR\ Cap_s)}{h} - \sum_r Cleared\ Capacity_r * \left(\frac{Offer_r}{ICAP_r * MEAF_r}\right)$$

Subject to:

Equation 2: Hourly capacity balance constraint

For every hour, the cleared hourly capacity should satisfy the reliability requirement as defined by the VRR curve:[4]

$$\forall\ h, \sum_r Hourly\ Capacity_{r,h} = \sum_s VRR_{s,h}$$

Equation 3: Hourly resource availability constraint

For every resource, the cleared hourly capacity for every hour should not exceed its corresponding hour's available capacity:

$$\forall\ (r,h), Hourly\ Capacity_{r,h} \leq Availability_{r,h}$$

Equation 4: Annual capacity clearing constraint

For every resource, the cleared annual capacity is the maximum of all cleared hourly capacity:

$$\forall\ r, Cleared\ Capacity_r \geq Hourly\ Capacity_{r,h}$$

Equation 5: Hourly reliability requirement constraint

For every hour, the cleared VRR segment should not exceed its maximum allowed MW:

$$VRR_{s,h} \leq Max\ VRR_{s,h}$$

Example

Consider a simple capacity market with only one LDA and only 10 hours in the Delivery Period (DP) with hourly vertical demand curves. Table 1 shows the ICAP, MEAF, ACAP and offer

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4 The notation, $\forall\ (r,h)$ means for every offered resource and for every hour in the delivery period.

price of capacity resources offered. Table 2 shows the hourly availability (HACAP MW) of capacity resources offered.

The average annual MEAF for each resource is derived from the historical hourly availability. For each hour and for each resource, $Availability_{r,h}$ in Equation 6 represents the expected hourly availability that accounts for forced, planned and maintenance outages plus derates for any reason. Equation 6 is the definition of MEAF.

Equation 6: Modified equivalent availability factor

$$MEAF_r = \frac{\sum_{hour} Availability_{r,h}}{ICAP_r * (Number\ of\ Hours\ in\ the\ Delivery\ Period)}$$

Under the SCM proposal, resources participating in the capacity auction specify their offers in $ per delivery period, which equals the annual net avoidable cost. Equation 7 shows the derivation of the offer price in $ per MW-Hour.

Equation 7 Offer price

$$Offer\ Price_r\ (\$/MW - Hour) = \frac{Offer_r\ (\$/\ Delivery\ Period\ )}{MEAF_r * ICAP_r * (Number\ of\ Hours\ in\ the\ Delivery\ Period)}$$

The market clears based on the expected hourly availability. For example, the MEAF of the coal resource, 0.640, is calculated as expected available MW-Hours (320 MW-Hours) divided by the total MW hours in the delivery period if the resource were available in all hours (50 MW * 10 hours = 500 MW-Hours). In this example, the coal resource is assumed to be unavailable for two hours in the delivery period due to a planned outage (0.20 EPOF). The forced outage rate for each hour varies. For example, for the coal resource, there is a 50 percent forced outage rate in Hour 4. The coal resource equivalent forced outage rate for the entire delivery period is 0.16. The MEAF of the wind resource, 0.475, is calculated as available hours (190 MW-Hours) divided by the total MW-hours in the delivery period if the resource were available in all hours (40 MW * 10 hours = 400 MW-Hours). The MEAF of the solar resource, 0.200, is calculated as available hours (80 MW-Hours) divided by the total MW hours in the delivery period if the resource were available in all hours (40 MW * 10 hours = 400 MW-Hours).

It is assumed that resources are offered flexibly, not in blocks, meaning that any number of MW could clear. For example, the cleared capacity of the coal resource could vary between 0 HACAP MW and 50 HACAP MW, the highest hourly availability offered. The average hourly availability of the coal resource for the delivery period is calculated as 32.0 (50*0.640) ACAP MW. The offer price of the coal resource, $32,400.00 per delivery year, translates to $101.25 per MW-Hour ($32,400.00/(0.640*50*10)). The coal resource will fully recover its total offer price of $32,400, if the resource clears its ACAP in the auction, and the actual resource availability in the energy market in the delivery year equals or exceeds the expected MEAF of 0.640.

Table 1 shows, for each resource, the ICAP, the offer in dollars per delivery period, the offer in dollars per MW-delivery period using ACAP, the MEAF, the average available capacity or ACAP, and the offer in dollars per MW-hour using ACAP.

Table 1 Resource ICAP, availability, offer price

	ICAP MW	Offer ($/DP)	Offer ($/MW-DP)	MEAF	ACAP MW	Offer ($/MW-Hour)
Nuclear	100.0	$54,000.00	$540.00	1.000	100.0	$54.00
Solar	40.0	$7,200.00	$900.00	0.200	8.0	$90.00
Wind	40.0	$3,600.00	$189.47	0.475	19.0	$18.95
Coal	50.0	$32,400.00	$1,012.50	0.640	32.0	$101.25
Oil	70.0	$57,600.00	$1,152.00	0.714	50.0	$115.20

Table 2 shows the hourly availability of each resource, defined as HACAP.

Table 2 Availability of resources by hour

	Availability (HACAP MW)										ICAP
	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	MW
Nuclear	100	100	100	100	100	100	100	100	100	100	100
Solar	0	0	5	10	25	25	10	5	0	0	40
Wind	10	30	20	20	10	20	20	20	10	30	40
Coal	45	0	0	25	30	35	45	45	45	50	50
Oil	52	51	51	50	50	49	51	49	49	48	70

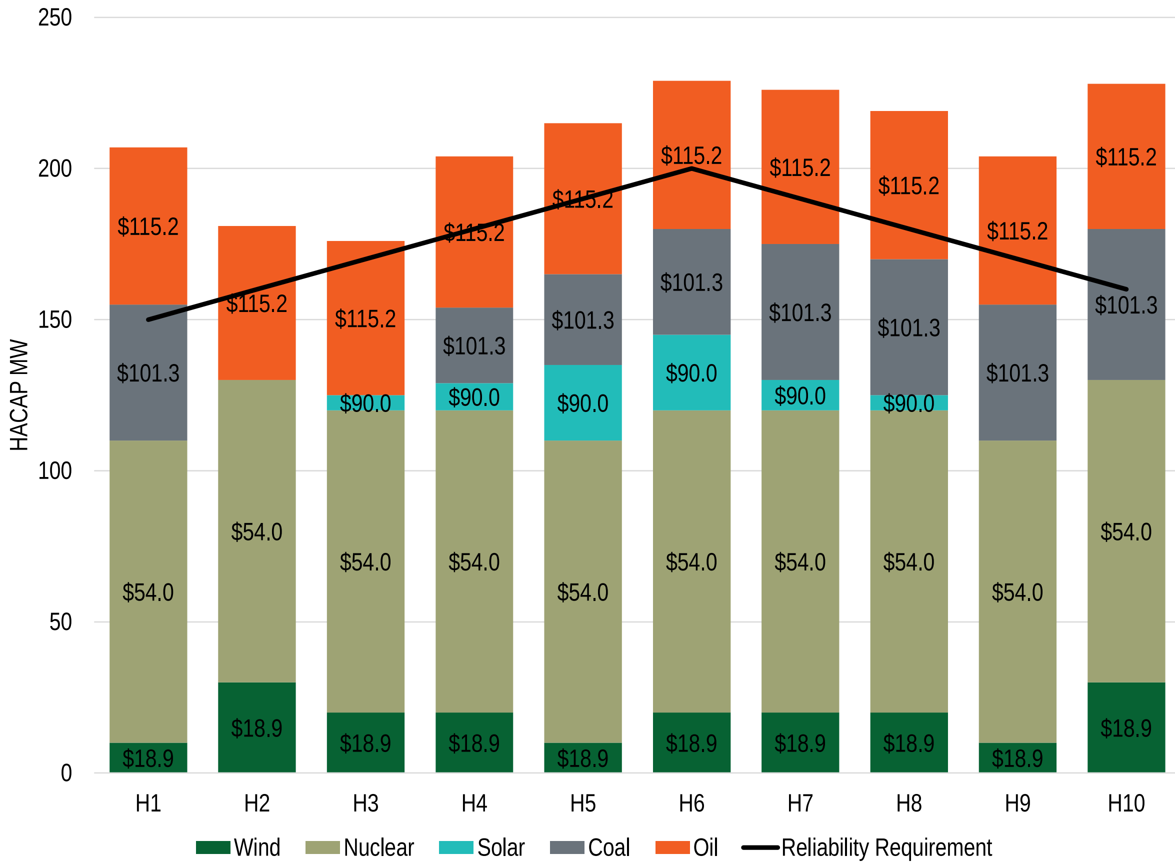
Table 3 shows the hourly system reliability requirement.

Table 3 Hourly reliability requirement

	Hour									
	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10
Reliability Requirement (MW)	150	160	170	180	190	200	190	180	170	160

Figure 1 compares the reliability requirement to the resource availability (HACAP MW) for each hour in the delivery period.

Figure 1 Availability and reliability requirement



In this simple example, since an hourly vertical reliability requirement is used in place of a sloped VRR curve, the objective function of the clearing process is minimizing the total cost of procurement, rather than maximizing the surplus as specified in the general formulation.[5]

Table 4 shows the results of the clearing process.

The coal resource would clear 15 HACAP MW of the offered maximum hourly availability of 50 HACAP MW with 0.640 MEAF. The offered average hourly availability of the coal resource for the delivery period was 32 ACAP MW. The clearing quantity, 15 HACAP MW (30 percent of the maximum offered HACAP of 50 MW) is equivalent to average hourly availability of 9.6 ACAP MW (30 percent of 32 ACAP MW) for the delivery period. The clearing price is set by the offer of the marginal resource. The marginal resource in this example is the oil resource. The offer price of the oil resource is $115.20 per MW-Hour.

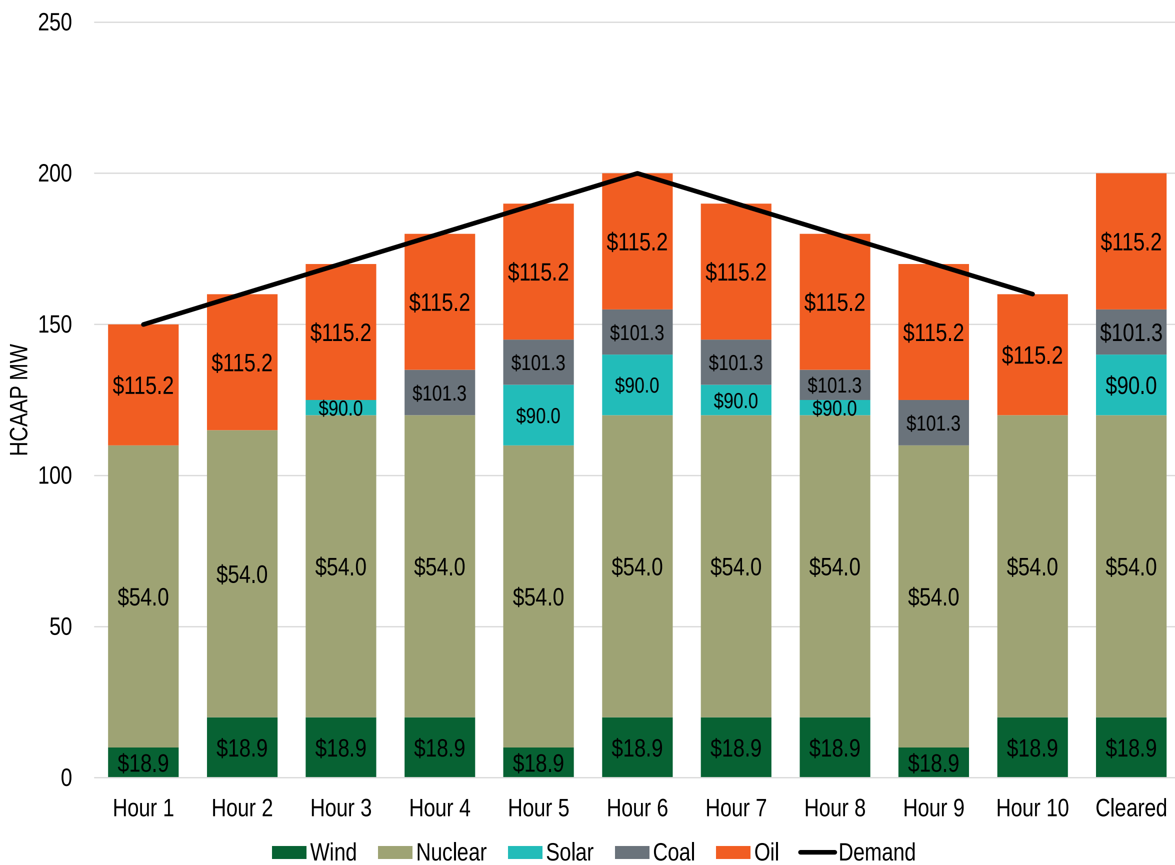
5 If the demand is perfectly inelastic (vertical demand curve), the objective of maximizing surplus is equivalent to the objective of minimizing cost.

Table 4 Auction results

	ICAP MW	Minimum Hourly Availability (HACAP MW)	Maximum Hourly Availability (HACAP MW)	MEAF	Cleared (HACAP MW)	Cleared (ACAP MW)
Nuclear	100.0	100.0	100.0	1.000	100.0	100.0
Solar	40.0	0.0	25.0	0.200	20.0	6.4
Wind	40.0	10.0	30.0	0.475	20.0	12.7
Coal	50.0	0.0	50.0	0.640	15.0	9.6
Oil	70.0	48.0	52.0	0.714	45.0	43.3

Figure 2 compares the reliability requirement to the resource availability (MW) for each hour in the delivery period. The right most bar in Figure 2 shows the annual cleared capacity (HACAP MW) for each resource type and the sum of the cleared capacity.

Figure 2 Reliability requirement, hourly cleared (HACAP MW) and annual cleared (HACAP MW)



The formulation ensures that the subset of resources needed to meet the reliability requirement of high demand hours are also available to meet the reliability requirement of all hours. In this example, 45 HACAP MW of the oil resource, offered at $115.20 per MW-Hour, are needed to meet the reliability requirement of Hour 3. In Hour 3, the availability of nuclear, solar and wind resources together add to 120 HACAP MW or 45 HACAP MW less than the reliability requirement of 170 MW. Once the oil resource has been cleared for an hour, the marginal cost of clearing 45 HACAP MW of the oil resource for all the other hours is $0. The clearing solution reflects this fact.

The clearing results in this example demonstrate the tradeoffs between clearing a cheaper capacity resource with lower availability versus clearing an expensive capacity resource with higher availability. For example, the wind resource, offered at $18.95 per MW-Hour, would only clear 20 HACAP MW of the offered maximum hourly availability of 30 HACAP MW. Additional clearing of wind resource would not displace other resources as a result of the hourly availability pattern of the wind resource. In the two hours where the wind resource is available to clear more than 20 HACAP MW, Hour 2 and Hour 10, the marginal value of additional capacity is $0 because the capacity cleared in the high demand Hour 6 is also available in Hour 2 and Hour 10 and is greater than the reliability requirements in those hours. Similarly, the solar resource, offered at $90.00 per MW-Hour would only clear 20 HACAP MW of the offered maximum hourly availability of 25 HACAP MW. The solar resource would not displace other resources as a result of the hourly availability pattern of the solar resource.

Equation 8 shows the formula for calculating capacity revenue for each resource under the SCM proposal. The numerator of the second term, ICAP*MEAF (ACAP MW), represents the average availability of the resource during the delivery period. The denominator of the second term, $Max(Availability_h)$, represents the highest hourly expected available capacity MW. A fully cleared resource would show $Cleared\ MW$ equal to $Max(Availability_h)$ and Equation 8 would reduce to ACAP * hourly clearing price * hours in the delivery period. For a partially cleared resource that offered flexibly in the capacity auction, the capacity revenue equals the ratio of $Cleared\ MW$ to $Max(Availability_h)$ times the result of Equation 8 for a fully cleared resource. In the example, it is assumed that all resources are offered flexibly, not in blocks, meaning that any number of MW could clear. The cleared quantity of the nuclear resource (100 HACAP MW) is the same as the highest hourly expected available capacity of the nuclear resource (100 HACAP MW). The cleared quantity of the coal resource (15 HACAP MW) is thirty percent of its highest hourly expected available capacity (50 MW).

Equation 8 Capacity revenue

$$\begin{matrix} Capacity \\ Revenue \\ (\$/DP) \end{matrix} = \begin{pmatrix} Cleared \\ MW \\ (HACAP\ MW) \end{pmatrix} * \frac{ICAP * MEAF}{Max(Availability_h)} * \begin{pmatrix} Clearing \\ Price \\ (\$/MW - Hour) \end{pmatrix} * \begin{pmatrix} Number\ of \\ hours\ in\ DP \end{pmatrix}$$

Table 5 shows the total capacity revenue earned by each resource for the delivery period under the SCM proposal. The capacity revenue of the coal resource, $11,059.20 per delivery period is calculated as cleared capacity (15 HACAP MW) multiplied by the average availability during the delivery period, ICAP*MEAF (50*0.640), divided by the maximum hourly expected availability (50 HACAP MW), multiplied by the clearing price ($115.20/MW-Hour), and multiplied by number of hours in the delivery period (10). Alternatively, the capacity revenue of the coal resource $11,059.20 per delivery period is calculated as cleared average availability (9.6 ACAP MW) multiplied by the clearing price ($115.20/MW-Hour) and multiplied by the number of hours in the delivery period (10).

Table 5 Capacity revenue

	ICAP MW	Minimum Hourly Availability (HACAP MW)	Maximum Hourly Availability (HACAP MW)	MEAF	Cleared (HACAP MW)	Cleared (ACAP MW)	Clearing Price ($/MW-Hour)	Capacity Revenue ($/DP)
Nuclear	100.0	100.0	100.0	1.000	100.0	100.0	$115.20	$115,200.00
Solar	40.0	0.0	25.0	0.200	20.0	6.4	$115.20	$7,372.80
Wind	40.0	10.0	30.0	0.475	20.0	12.7	$115.20	$14,592.00
Coal	50.0	0.0	50.0	0.640	15.0	9.6	$115.20	$11,059.20
Oil	70.0	48.0	52.0	0.714	45.0	43.3	$115.20	$49,846.15

Table 6 compares the offer ($/DP) to capacity revenue ($/DP) under the SCM proposal. In this example, the nuclear, solar and wind resources are paid more than their total offer ($/DP) as a result of inframarginal rents. In this example, the marginal oil resource is paid their offer and the coal resource is paid more than their offer for their cleared ACAP MW, but both do not fully recover their offer price because they do not fully clear. These resources would be eligible to receive make whole payments if they were offered and cleared as inflexible resources, the same as the existing capacity market rules.

Table 6 Offer and capacity revenue

	Offered (ACAP MW)	Cleared (ACAP MW)	Offer ($/DP)	Capacity Revenue ($/DP)
Nuclear	100.0	100.0	$54,000.00	$115,200.00
Solar	8.0	6.4	$7,200.00	$7,372.80
Wind	19.0	12.7	$3,600.00	$14,592.00
Coal	32.0	9.6	$32,400.00	$11,059.20
Oil	50.0	43.3	$57,600.00	$49,846.15

Under the SCM proposal, capacity is paid in the delivery year only when available to provide energy by hour. Table 7 shows an example availability of the cleared resources in the energy market during the delivery year. In this example, the actual availability (MEAF) of all resources match their offered availability (MEAF) in the auction. However, the hourly availability (HACAP MW) in the delivery year does not exactly match the hourly availability (HACAP) offered by these resources in the capacity auction. For example, in the auction, the solar resource was offered as available for 5 HACAP MW in Hour 3 (Table 2). The actual availability in the Hour 3 of the delivery period was assumed to be 0 HACAP MW. However, at the end of the delivery period, the actual availability of the solar resource in the energy market (Actual ACAP = ICAP * Actual MEAF) matches the offered availability (Offered ACAP= ICAP * Offered MEAF) in the capacity auction.

Table 7 Actual availability of capacity resources in the energy market in the delivery period

	Availability in the Energy Market (HACAP MW)										Actual
	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	MEAF
Nuclear	100	100	100	100	100	100	100	100	100	100	1.000
Solar	0	0	0	5	35	35	5	0	0	0	0.200
Wind	10	30	20	20	10	20	20	20	10	30	0.475
Coal	30	0	20	20	40	50	40	30	50	40	0.640
Oil	70	70	0	70	50	50	50	50	50	40	0.714

Table 8 shows the capacity market revenue paid to cleared resources based on their actual availability in the energy market in the delivery period as shown in Table 7. If the actual availability (MEAF) in the energy market for the full delivery period matches the offered MEAF in the capacity auction, the resource would be paid the full capacity clearing price for the cleared ACAP MW. For example, the nuclear resource cleared its full 100 ACAP MW offered in the auction. The capacity payment of $115,200 per delivery period (100*10*115.20) would be paid to the nuclear resource over the full the delivery period if its MEAF in the energy market was equal to 1.000, the MEAF offered in the capacity auction. For a partially cleared resource such as the oil resource, the capacity payment would be reduced proportionately. The maximum offered expected HACAP of the oil resource in the auction was 52 MW (Table 4). However only 45 HACAP MW or 87 percent of the highest offered hourly availability of 52 HACAP MW for oil resource cleared in the capacity auction. This factor is applied for every hour (Table 8, Factor for Partially Cleared Resources). For example, in Hour 1, 70 MW of oil resource availability in the energy market would result in a capacity payment of $6,978 (70*$115.20*0.87). If the oil resource were awarded a make whole payment, in Hour 1, 70 MW of oil resource availability in the energy market would result in capacity payment of $8,064 (70*$115.20). With a make whole payment, the oil resource would be paid $57,600 by the end of the delivery period if the MEAF in the energy market was equal to 0.714, the MEAF offered in the capacity auction. This payment equals the offer price of the oil resource in the capacity auction. Since the oil resource is the marginal resource, the capacity payment would exactly equal their offer price.

Table 8 Capacity market revenue

	Capacity Revenue ($/Hour)										Total	Factor for Partially
	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	($/DP)	Cleared Resources
Nuclear	$11,520	$11,520	$11,520	$11,520	$11,520	$11,520	$11,520	$11,520	$11,520	$11,520	$115,200	1.00
Solar	$0	$0	$0	$461	$3,226	$3,226	$461	$0	$0	$0	$7,373	0.80
Wind	$768	$2,304	$1,536	$1,536	$768	$1,536	$1,536	$1,536	$768	$2,304	$14,592	0.67
Coal	$1,037	$0	$691	$691	$1,382	$1,728	$1,382	$1,037	$1,728	$1,382	$11,059	0.30
Oil	$6,978	$6,978	$0	$6,978	$4,985	$4,985	$4,985	$4,985	$4,985	$3,988	$49,846	0.87

Appendix 2:

Issues with the CP model

The SCM proposal for the capacity market recognizes that the Capacity Performance (CP) model was a failed experiment.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The potential risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market. If the uncertainty about the level of penalties and who is paying penalties and the more general uncertainty about the market design affects the incentives to invest, there is a risk to the market.

The CP incentives are weaker than generally appreciated. In CP, the required performance is significantly lower than it should be. In the CP model, the combination of B and UCAP means that resources are obligated to provide significantly less than full ICAP. This significantly weakens the performance incentives under CP. That reduced obligation is inconsistent with the broader PJM market design which requires capacity resources to offer energy equal to 100 percent of ICAP every day in the energy market. For example, under the CP model, with a B of 0.80 and an EFORd of 0.95, the required performance would be only 76 percent of ICAP. With an EFORd of 0.50, the obligation would be only 40 percent of ICAP.

Winter Storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the time period of Elliott, the 2022/2023 Delivery Year.[6] In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement

[6] See the *2022 State of the Market Report for PJM*, Volume 2, Section 3: Energy Market, pg. 210.

transactions is complex and very difficult to administer, and includes subjective elements. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

There is no reason that in a rational market design two cold days would result in a crisis and a level of administrative complexity that threatens to undermine the incentives to invest in existing and new supply resources at a time when those resources are needed. The CP design undermines incentives rather than creating positive incentives to invest and perform.

The IMM supports FERC's elimination of the CP MSOC defined as Net CONE times B and the return to the MSOC defined by net avoidable costs (ACR), and recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk.[7] The use of Net CONE as the basis for the CP penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily defined risk for generators, creates corresponding arbitrary complexity in the calculation of CPQR and ultimately raises the price of capacity. (See Appendix 3.)

The CP design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

Issues with ELCC

The SCM proposal for the capacity market recognizes that the ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market.

ELCC was developed as, and remains, a planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource or at least a thermal resource. The motivation made sense but the actual application cannot work in markets for intermittent or thermal resources. ELCC has been used in PJM to

7 *See* 176 FERC ¶ 61,137 (September 2, 2021)

calculate the reliability contribution of incremental intermittent resources, assuming that the existing fleet of thermal resources continues to provide the underlying reliability for 8,760 hours. The simple underlying logic of ELCC makes sense. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, currently credited with full capacity value, that are much less available than intermittent resources that are derated. ELCC does not currently apply to thermal resources. PJM has not explained how ELCC could be applied to all resources. If ELCC were to be applied to all resources simultaneously rather than based on an assumption about the existing fleet, the computational problem becomes effectively impossible when simultaneously clearing a capacity market based on hourly availability of all resources and load data, and more so if locational attributes are included. While PJM uses average ELCC, the correct application of ELCC, from a mathematical and economic perspective, is to define ELCC as the marginal ELCC. It is clear that as the market share of intermittents grows, the marginal value of intermittents will decrease quickly. The result will be that a 100 MW solar resource will have a very small capacity value, e.g. 5 MW, but have a performance obligation, and associated penalty exposure, equal to its full CIRs of 100 MW where the CIR MW equal the ICAP MW. PJM has not yet included the correct requirement for CIRs and availability consistent with the ELCC logic.[8] That tension between the derated MW that qualify as capacity and the obligation to perform at full ICAP will make offering intermittent resources as capacity increasingly untenable. This is not an argument for average ELCC, which is clearly wrong. It is an argument for abandoning ELCC as the definition of capacity for intermittents or for thermals and replacing ELCC with a metric that reflects the actual availability of all resources. This will ensure comparable treatment within and across categories of capacity resources.

Another significant flaw in the ELCC approach is that ELCC, as applied by PJM, does not work locationally. That is a fatal flaw in a capacity market that has included locational supply and demand characteristics as a fundamental element since the 2007 introduction of the RPM design. A recent example is the case of the DPL-S LDA in the BRA for the 2024/2025 Delivery Year. Solar resources in DPL-S had much lower ELCC values than the system average ELCC value. The result, including other resources also, was a mismatch between the demand curve and the supply curve in DPL-S, which led to a price that did not reflect locational supply and demand fundamentals.[9]

8 Although PJM has not yet modified the OATT to recognize that the obligation of derated resources is the full CIR value rather than the derated value, that is the clear implication of the ELCC/CIR discussions in the stakeholder process and the requirement that derated resources have CIRs equal to the highest energy output assumed in the ELCC calculation of the derated MW value.

9 See "Comments of the Independent Market Monitor for PJM," Docket No. ER23-729-000 and Docket No. EL23-19-000 (January 20, 2023).

Reliability on an average annual or seasonal basis is not reliability. Accounting for hourly availability on a locational and resource specific basis more accurately defines availability than offering capacity based on derating by a simple class average, non locational availability factor, e.g. PJM's use of technology class ELCC availability factors for all hours and for the entire PJM market. The hourly approach also incorporates the essential locational characteristics of the capacity market by recognizing availability on a resource specific basis.

Appendix 3:

The MSOC in the Capacity Market

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and the derivation simply assumed the answer. The CP market seller offer cap was incorrectly and significantly overstated as a result. The FERC has since corrected the MSOC definition, but some participants continue to attempt to revive the offer cap based on Net CONE.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[10] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[11] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[12] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[13] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[14] That assumption/assertion was the basis for using Net CONE as the penalty rate.

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10 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.

11 See page 55 of CP Filing.

12 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.

13 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

14 See page 43 of CP Filing.

The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on Net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The experience of Winter Storm Elliott and the associated penalties changed the calculation of the CPQR risk mitigation component of the ACR offer caps. Incorporating the Elliott data in the history used to calculate an appropriate CPQR led to very large CPQR values for some poorly performing resources. Correctly calculated maximum CPQR values increased from less than $10 per MW-day to about $50 per MW-day while some participants proposed CPQR values in excess of $100 per MW-day. This impact illustrates the circular logic of the CP model. The CP model creates arbitrarily high penalty rates which affect CPQR which increase the ACR market seller offer caps. The risk is created by the CP model and then the cost to mitigate that risk is compensated within the CP model. Under the SCM approach, the arbitrarily and extreme penalties would be eliminated and therefore the impact on CPQR and the impact on capacity market clearing prices would be eliminated. There would continue to be risk and there would continue to be a cost to mitigate that risk, but the risk would be fundamental to the operation of the market rather than based on an assumption about the correct clearing price.

The IMM supported the modified CP filing and prepared the mathematical appendix.[15] But after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the

15 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).

offer cap, it became clear to the IMM that the CP model was a mistake.[16] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact.[17] The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[18] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the IMM, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[19] [20]

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16 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

17 See "Analysis of the 2022/2023 RPM Base Residual Auction – Revised," (January 13, 2023) and the *2022 State of the Market Report for PJM*, Volume 2: Section 5: Capacity Market (March 9, 2023).

18 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

19 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").

20 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.