Summary:

The PJM RPM capacity market design embodies many improvements over the prior PJM capacity market. Six of these improvements are particularly important. First, the RPM capacity market procures capacity in a three-year forward timeframe. Second, the RPM capacity market includes locational requirements and eliminates the grandfathering of incumbent capacity resources. Third, the RPM design introduces a downward sloping demand curve in the procurement of capacity. Fourth, the RPM design includes improved performance incentives for suppliers. Fifth, the RPM design procures capacity on an annual basis and allocates the capacity costs to LSEs on a daily basis. Sixth, market power mitigation mechanisms are explicitly defined.

1. Incentive to Attract Efficient Level of Investment

The PJM RPM model has a number of features that should work together to produce the level of investment needed to sustain the target level of generating capacity. The target level of generating capacity will be supported by a capacity payment in addition to net energy and ancillary service market revenues. The capacity payment is partly based on the estimated cost of new capacity (CONE), partly based on estimated net energy and ancillary service revenues, and partly market based, determined by the offer prices of new capacity and adjustments over time to CONE based on outcomes in the base residual auction.

In addition, the PJM RPM model includes a demand curve for capacity (variable resource requirement) that will likely tend to stabilize capacity prices, limiting price increases in the event of capacity shortfalls relative to the target and limiting price decreases in the event of excess capacity relative to the target level. If the estimated CONE differs materially from the capacity price needed to maintain reliability, however, the level of capacity procured through the base residual auction may be materially different from the reliability target.

The estimated net energy and ancillary service revenues are calculated based on a peak hour dispatch taking into account the characteristics of the hypothetical marginal resource, rather than a perfect dispatch. After an initial period, the calculation on estimated net energy and ancillary service revenues will be on a rolling three year basis. The characteristics of the reference resource used to determine the CONE and net energy and ancillary service revenues are specified in the tariff.
The degree to which the RPM capacity model will provide incentives for the efficient level of investment depends on a number of features of the RPM design:

- How well the estimated CONE approximates the actual capacity payment required to support the development of new capacity;\(^1\)
- The degree to which the estimated net energy and ancillary services revenues are consistent with market expectations; and
- Whether the process used to generate the forecast of capacity needs produces forecasts consistent with actual consumer requirements.

2. **Allow Generation, Transmission and Demand Response to Compete**

Under the RPM design, demand response resources\(^2\) and transmission upgrades\(^3\) directly compete with existing and new generation resources to satisfy the resource adequacy requirement in the forward auction.\(^4\) There is also a mechanism for the procurement of resources in the forward auction to be reduced to reflect the expected level of interruptible load resources that would be available during the delivery year.\(^5\)

3. **Does the Proposal Ensure Retention of Existing Economic Resources?**

Existing economic resources would be paid the zonal capacity market clearing price in the forward auction. Existing generating resources would be subject to offer capping, however, which could cause economic resources to exit the market in some circumstances. In particular, offer capping of existing capacity in the forward auction could cause the exit of economic capacity if the offer cap were set at an inappropriately low level\(^6\) and incremental capacity needs were met by self-scheduled capacity resources.

The settlement contains provisions for minimum offer prices for new generation but these provisions appear meaningless given the ability of capacity buyers to self-

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1. This depends both on the accuracy of the estimates of the cost of constructing the hypothetical marginal unit and on whether the estimate accounts for all costs and risks borne by a capacity supplier. For example, it is not clear if the process for calculating CONE accounts for the expected cost of failed projects.
2. See Schedule 6 to the PJM RAA.
3. Qualifying transmission upgrades create incremental capacity transfer rights which are valued in the base residual auction, see Attachment DD, Section s5.14 (d) and 5.16.
4. The base residual auction conducted three years prior to the year of delivery.
5. See Schedule 6 to the RAA, Attachment DD, Sections 2.36 and 2.44.
6. This could be a result of mis-estimation of the net energy and ancillary service revenues, or mis-estimation of avoided costs. The demand curve would tend to limit the impact of such mis-estimation of net energy revenues or avoidable costs but the stabilizing effect of the demand curve will be reduced in CONE is understated or the risks of participating in the capacity market are understated.
schedule capacity at a zero offer price. Indeed, in a situation in which capacity buyers may be contracting forward for baseload generating capacity with a development time longer than the three year RPM cycle, one should anticipate that new capacity might be offered into the market as a price taker, covered by longer-term energy and capacity contracts.

4. **Promote Acquisition of Capacity in Advance of Needed Timeframe**

The proposal will generally cause capacity to be procured at least 3 years prior to the delivery year, with a potential for additional capacity to be acquired in the 2nd incremental auction a year prior to the delivery year, if the initial load forecast appears to be low. Incremental auctions to replace delayed or cancelled projects will be conducted 2 years prior to the delivery year and in January of the delivery year.\(^7\)

Load serving entities are free to enter into longer term capacity contracts and to purchase capacity more than three years prior to the delivery year. The RPM design assures that capacity will be procured on behalf of consumers served by LSEs lacking a long-term obligation to serve no less than 3 years prior to the delivery year, but does not preclude LSEs from contracting for energy and capacity more than three years prior to the delivery year. The term of the procurement in the centralized auction will generally be one year at a time.

Similarly, the RPM design will not interfere with the procurement of baseload capacity (typically capacity having a greater than three year development time) by LSEs with a long-term obligation to serve. Such LSEs can enter into contracts for baseload capacity more than three years prior to delivery and then offer the capacity in the RPM auction when the project’s completion date enters the time frame of the RPM process.

It is unclear, however, whether the three year forward procurement will result in the efficient level of contracting for baseload resources on behalf of consumers served by LSEs lacking a long-term obligation to serve.\(^8\) There is some level of expected future prices relative to long-run generating costs that would induce the construction of baseload capacity to serve load under short-term contracts, but it is possible that in the absence of longer than three year forward energy and capacity contracts, various regulatory, political and market risks may lead to a suboptimal level of investment in baseload capacity to serve retail access load.

5. **Does the Proposal Make Available Transparent Price Signals?**

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\(^7\) Attachment DD, Section 17. The Delivery year will run June through May.

\(^8\) The extent to which the efficient level of baseload capacity is built depends in part on the willingness of the owners of such resources or other entities in the market to accept the energy price risk associated with such resources.
If capacity is contracted for by the RTO in the forward capacity auction, then there will be price signal to guide investment decisions in generation, transmission and demand response projects, to support a pipeline of generation, transmission and demand response projects in the development stage, and to provide information supporting regulatory decisions.

If much or all of the capacity cleared in the forward auction is capacity previously acquired through bilateral long-term contracts, the auction clearing price may not provide a meaningful price signal. However, if the implementation of RPM were to lead to all consumer capacity needs being met through long-term bilateral contracts, the RPM proposal would likely be viewed as working extremely well without regard to the quality of the price signals in the forward auction.

Special rules in the PJM RPM design for handling lumpy investments could potential introduce some murkiness into the auction price signal.

6. Does the Proposal Provide Performance Incentives?

A system of peak-hour availability charges and credits will provide improved incentives (relative to the prior PJM UCAP market design) for generation resources to be available during stressed system conditions under the PJM RPM design. The PJM RPM tariff identifies roughly 500 hours during the year that are potentially high load periods. The calculation of availability will limited to the subset of these high load hours during which the resource would have been economic to operate based on its cost-based offer price. Generators whose availability during these hours is less than their EFORd will have their resource adequacy payment reduced proportionately.

The PJM Peak Hour incentives will accommodate the needs of energy limited resources by allowing these resources to, within the constraints of the overall PJM market power mitigation plan, limit the amount of energy they are dispatched to provide during the peak hours by raising their offer price, without being penalized for reduced peak hour availability. How the RPM Peak Hour Availability Charges in practice affect the performance of energy limited resources in PJM will be observed in coming years but

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9 The PJM RPM capacity market is designed as a basically physical market with little role for arbitrage to provide transparent price signals in the event most capacity is procured through long-term bilateral contracts.

10 See, for example, Attachment DD, Sections 5.12 (a) and 5.14(d).

11 The PJM RPM tariff defines these hours as non-holiday weekdays 2-7 p.m. June- August and 7 a.m.-9 a.m. and 6-8 p.m. December through January; See Attachment DD, Section 10. The precise definition of the peak hours by PJM is not important; the definition can be modified to reflect California conditions.

12 Attachment DD, Section 10 (e).

13 There are exceptions for generation resources that are not available for reasons outside management control, such as transmission outages, gas pipeline outages, etc.
is not yet known. Since PJM currently has fewer energy limited resources than California, the application of RPM in PJM may not fully demonstrate the workability of the RPM Peak Hour Availability Charge for the CAISO resource mix.

7. **Allow for Cost-Effective Tracking Mechanism for Monitoring and Compliance**

Under RPM, PJM is responsible for contracting for capacity through the forward auction, enabling PJM to ensure that the target level of capacity is contracted for in the forward auction. PJM verifies the increase in capacity transfer capability associated with transmission upgrades and upgrades must execute a Facilities Study Agreement for the upgrade.\(^{14}\) PJM also determines the maximum capacity that can be offered by capacity sellers but the tariff does not describe what criteria are to be applied to defining the maximum capacity of planned units.\(^{15}\)

The PJM RPM design provides a mechanism for generation developers to buy replacement capacity, either through bilateral contracts or through incremental auctions, in the event that their contracted project is delayed or becomes infeasible (as a result of permitting issues for example).

Resources, whether generation, transmission or demand response are subject to paying deficiency charges if the capacity is not delivered for any or all of the delivery year.\(^{16}\) The PJM tariff also imposes a credit requirement on entities seeking to supply capacity in an RPM auction from new generation resources, from transmission upgrades, from a new demand response resource, or from a resource external to PJM that has not yet contracted for firm transmission service.\(^{17}\)

8. **Does the Proposal Complement the MRTU Market Design, Systems and Operations?**

The initial PJM RPM design provides for the development of up to 23 capacity regions and includes a process for PJM to identify additional capacity regions over time. How well this process for identifying new capacity regions works in practice will not be known for several years.

One likely issue in applying a RPM like capacity market design to California is that PJM’s energy markets provides for a much greater level of disaggregation of energy pricing than the current CAISO MRTU design. It is very likely that the number of

\(^{14}\) Attachment DD, Sections 5.6.1(g) and 5.6.4.  
\(^{15}\) Attachment DD, Section 5.6.6.  
\(^{16}\) Attachment DD, Sections 8, 11 and 12.  
\(^{17}\) PJM OATT, Sheet 523 I 02-05.
capacity regions in California under a RPM like model would greatly exceed the three LAPs currently proposed for energy pricing under the MRTU tariff.

Inconsistency between the locational requirements under a RPM type capacity market and those relevant for energy market pricing could adversely impact both investment incentives and forward hedging in energy markets. Transmission upgrades, for example, that benefit capacity buyers within a narrow capacity market region would also affect congestion and energy prices in the LAP, with the impact on energy prices spread over all buyers in the LAP, rather those within the capacity zone. This divergence in the incidence of impacts between the capacity and energy markets could complicate evaluation of both market-based and regulated transmission investments.

The RPM design does not appear to provide for intra-RPM zone delivery rights which would define entitlements to capacity transfer rights in the event new zones were created.

9. How Does the Proposal Provide Incentives for a Diverse Resource Mix?

The PJM RPM model provides incentives for the development of both demand response and transmission upgrades by allowing these resources to compete with generation resources within the forward auction. The PJM RPM model does not directly provide incentives for fuel diversity or for a mix between baseload and peaking generation.

9a-10. Locational Requirements

The initial PJM RPM design provides for the development of up to 23 capacity regions and includes a process for PJM to identify additional capacity regions over time. How well this process for identifying new capacity regions works in practice will not be known for several years. Even then it may not be clear whether the process would be applicable to the geographic distribution of load and resources in California.
9b-11. Quick Start, Fasting Ramping, and System Requirements

The settlement agreement for RPM eliminated the features involving payments for quick start and fast ramping units from the capacity market and provided that PJM would make separate filings to provide improved incentives for these resources through changes in its energy and ancillary service markets.

9c-12. Resources Able to Shift Intermittent Resource Output from Off-Peak to On-peak

The PJM RPM model does not provide any special incentives for the development of resources with inter-temporal energy shifting capability. However, any resource capable of providing 12 hours of continuous operation can qualify as providing capacity, so pumped storage and other energy shifting resources can qualify for RPM capacity payments. The ability of output shifting resources to qualify for capacity payments in the PJM RPM model does not depend on whether they are intertemporally shifting the off-peak output of intermittent resources or of baseload resources.

13. Does it Minimize or Eliminate Need to Rely on Backstop Capacity?

How well the PJM RPM model avoids the need for a backstop mechanism to support needed capacity depends in part how the PJM capacity market clears on the capacity demand curve. If the estimates for CONE, the estimates of net energy and ancillary service market revenues, and adjustments for penalties and risks are accurate, the RPM mechanism should procure the intended level of capacity and avoid the need for a backstop process. This may not be the case if any of these cost elements are materially misestimated. The process for CONE to shift over time will help to gradually resolve such errors if the errors are not too large.

The extent to which the RPM model will be successful in avoiding the need for reliance on a backup mechanism will also depend on PJM’s ability to analyze potentially constrained capacity regions and to create new capacity zones in time to be accommodated within the forward auction design.

14. How Does the Proposal Allow for Effective use of Imports to meet RA R Requirements?

The PJM RPM model accounts for import supply in two ways. First, the model allows resources located outside the PJM control area to supply capacity into PJM if they have firm transmission service to PJM. In addition, the PJM RAA provides for PJM to take account of the capacity assistance available from other control areas in determining the

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18 PJM Manual 21 General, item 11.
overall PJM capacity requirement.\textsuperscript{19} Unlike California, however, the supply of import resources available to PJM during emergency conditions does not vary over a hydro cycle. The PJM capacity requirement is defined on an annual basis so would not readily accommodate capacity available in other regions as a result of peak diversity, although this can be accounted for by PJM in its determination of the overall capacity requirement.

15. **How Does the Proposal Ensure that all LSEs Recover the Cost of their Capacity Requirements and Ensure that Cost Shifting Does Not Occur between LSEs?**

Under the PJM RPM proposal, PJM contracts for capacity in the forward auction for an annual term, pays for the capacity during the delivery year, and allocates the cost of this capacity to, and recovers the cost from, the LSE serving the load on each day during the delivery year. The ability of LSEs to recover these capacity charges in unregulated retail prices or in their regulated rates depends on market conditions and the policies of state regulators. By defining the obligation on an annual basis and allocating all of the annual costs to LSEs on a daily basis, the PJM RPM design avoids the potential for cost shifts arising from differences between daily, monthly or seasonal capacity prices.

LSEs that choose to contract forward for capacity outside the framework of the PJM forward auction could incur higher or lower capacity costs than LSEs contracting for capacity through the auction, but that is a result of contracting choices, not cost shifting.

16. **How Does Proposal Accommodate Load Migration?**

Each LSE pays the capacity cost on the days for which it is responsible for serving its load, see 15 above.

17. **Is the Proposal Compatible with Short-Term and Long-Term Bilateral Procurement and/or Resource Ownership by LSEs?**

Yes. LSEs can enter into long-term capacity contracts and self-schedule the contracted capacity in the forward auction to cover their delivery year capacity obligation. The introduction of the downward sloping demand curve for capacity in the forward auction means that the amount of capacity an LSE would need to meet its obligation would depend on the price in the auction as well on its future load ratio share of peak demand. To help account for the uncertainty associated with the demand curve for capacity, there are special rules allowing self-scheduled capacity to be offered or not depending on where the capacity demand curve clears. The RPM market power mitigation provisions could require capacity to be sold in the forward auction at a low price, then charge the

\textsuperscript{19} PJM RAA Schedule 4, Sections C and D.
LSE for additional capacity purchased in a the second incremental auction at a higher price. Absent major misforecasts of demand, this effect should be small.

Bilateral contracts entered into more than 3 years prior to the delivery year to support the development of baseload capacity hedging both energy and capacity costs should be readily accommodated by the RPM design.

Conversely, LSEs that do not wish to enter into forward contracts for capacity need not do so and will pay the capacity price determined in the forward auction.

The PJM RPM proposal also includes a complex set of provisions (Fixed Resource Requirement) that permit entities with long-term obligations to serve load to meet their capacity obligations outside the framework of the forward auction.²⁰


The PJM RPM proposal accommodates self-provision of capacity. The combination of market power mitigation applied to the offer prices of existing resources and self-scheduling of new capacity could result in forward auction prices that are lower than the long-run supply price of capacity. The potential for strategic actions to depress capacity market prices in a capacity subregion is limited by the price of capacity in broader capacity regions, by the operation of the demand curve and by competition among capacity buyers to the extent it exists.

19. How Does the Proposal Mitigate Market Power?

The PJM RPM capacity market contains extensive provisions capping the offer prices of existing units and providing for the mitigation of offers by pivotal suppliers.²¹ The market power mitigation framework includes the application of preliminary market structure screens, a market structure test, mitigation of offer prices based on a calculated avoided cost metric, and extensive provisions dealing with adjustments for required capital expenditures. With regard to buyer market power (monopsony), the PJM RPM market rules contain provisions for minimum offer prices for new resources,²² but these provisions appear to have limited practical significance given the ability of LSEs to self-schedule capacity (i.e. offer capacity at a price of zero).²³

20. Will the Proposal Create Material Barriers to Entry?

²⁰ PJM RAA schedule 8.1.
²¹ Attachment DD, Section 6.
²² Attachment DD, Section 5.14 (h).
²³ Attachment DD, Sections 5.2 and 5.3.
The RPM mechanism does not grandfather the deliverability of existing capacity resources or introduce other asymmetries. Appropriately located entrants can displace incumbent generators by offering capacity at a lower price.

Credit coverage costs requirements are placed on generators, transmission projects and demand response projects that are in the planning stage. These credit requirements are not necessarily barriers to entry as they serve to assure performance, as do the sunk costs of incumbent suppliers.


The PJM capacity requirement is defined under RPM in terms of unforced capacity. Gross capacity procurement will be based on resource EF0Rd (Section 2.4) so if the resources offered in the base residual auction have low EF0Rd ratings, larger quantities of gross capacity will be procured in order to obtain the desired quantity of effective capacity. Resources will specify their EF0Rd in the base auction, and for the 1st and 2nd incremental auction. EF0Rd ratings for the 3rd incremental auction will be determined by PJM. Thus, the owner of a 100MW resource could initially offered the resource into the forward auction with an EF0Rd of 50%, selling 50MW of effective capacity in the forward auction. In the third incremental auction, PJM might assign the resource an EF0Rd of 75% based on the unit’s performance and characteristics. The additional 25MW of effective capacity could then be offered for sale in the third incremental auction, potentially being purchased by entities having lower current EF0Rds than they specified at the time of the forward auction. Significantly, increases between the initial EF0Rd and the EF0Rd specified by PJM do not change the total amount of effective capacity purchased by consumers and thus avoid the potential for consumers to pay for more capacity than PJM intended to contract for. This framework also enables non-traditional resources with low EF0Rds to compete with traditional resources on a level playing field.

The potential for capacity suppliers to physically withhold capacity from the forward auction by specifying an excessive EF0Rd is addressed by the requirement that existing resources be offered at an EF0Rd no higher than their actual EF0Rd over the preceding 12 months. The potential for capacity suppliers to be required to purchase capacity in the third incremental auction to cover an increase in EF0R gives rise to a risk that the supplier may need to buy capacity at a loss to cover a forward sale that was mandated by the market power mitigation provisions at a price determined by the offer cap. To

24 RAA schedule 8, Attachment DD sections 2.26, 2.55 and 5.4.
25 Attachment DD section 6.6 (a)
address this risk, capacity sellers are permitted to offer a portion of their existing capacity (based on historical variations in EFORd) at a price above the cap for existing capacity.

22. **How Will the Target Level of Capacity be Established?**

The PJM RPM model provides for PJM to forecast load based on a 50% probability of the forecast being higher or lower than the actual peak and does not address the energy price that should be assumed in developing this forecast.

23. **How Will the Cost of Excess Capacity be Allocated to LSEs Across the Various Zones?**

The cost of excess capacity procurement (arising from load forecast errors) will be allocated prorata to all LSEs serving load within the regions with misforecasted load during the delivery year.

24. **How Will the Proposal Account for the Affect of Low Hydro Years on Resource Capacity?**

The PJM RPM model does not explicitly account for variations in the available capacity of hydro generation associated with low hydro conditions. PJM requires that capacity resources be able to sustain their capacity rating for 12 continuous hours. In addition, capacity resources would be subject to penalties for outages during the peak hours. There is no other explicit adjustment for the impact of hydro conditions on hydro capacity. Section 6.6 (a) might operate to require that hydro resources be offered at a lower EFORd than they would be able to sustain during a low hydro year.

25. **How Will the Proposal Account for Energy Availability Constraints Associated with Western Hydro Cycle? Will all Resources have an Unlimited Energy Availability Requirement?**

The RPM model does not explicitly account for energy constraints on generation availability. PJM requires that capacity resources be able to sustain their capacity rating for 12 continuous hours. In addition, capacity resources would be subject to penalties for outages during the peak hours. The only energy availability requirement is the ability to generate for 12 continuous hours, but this does not mean 12 continuous hours 365 days a year. It is not known how the PJM RPM capacity model would perform during an Western energy constrained low hydro year.

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26 Attachment DD section 6.6 (b) and 6.7 (d) iii
26. Does the Mechanism Assure Performance by Capacity Suppliers?

Resources, whether generation, transmission or demand response are subject to paying deficiency charges if the capacity is not delivered for any or all of the delivery year. The PJM tariff also imposes a credit requirement on entities seeking to participate in each RPM auction by supplying capacity from new generation resources, from transmission upgrades, from a new demand response, or from a resource external to PJM that has not yet contracted for firm transmission service to ensure that resources offered in the forward auction have a financial commitment to carry through on the construction of the resource.

27. How will performance incentives for Suppliers affect the incentive of LSEs to bid in the Day-Ahead Market?

The Peak Hour Performance incentives will not undermine the incentive of LSEs to buy power in the day-ahead market as the peak hour availability charges are calculated based on forced outages and deratings. Resources will not incur peak hour availability charges if they are not on line because they were not committed in the day-ahead market. The peak hour performance charges will therefore not serve to insulate LSEs from the financial consequences of failing to buy power in the day-ahead market during high load conditions.

27. Attachment DD, Sections 8, 11 and 12.

28. Sheet 523 I 02-05.