Price Formation

Energy Price Formation Senior Task Force

December 14, 2018

Errata:

Jan. 9, 2019: edits were made on pages 19 and 20 to correct links.

Contents

Purpose

The purpose of this document is to provide background on the need for evolution of PJM's Energy and Reserve Markets and an explanation of the components of a comprehensive package as identified in the letter[1] issued by the PJM Board on December, 5, 2018.

The explanations of the changes PJM has proposed for the consolidation of the Tier 1 and Tier 2 synchronized reserve products, the implementation of a more dynamic reserve sub-zone, and the implementation of an operating reserve demand curve (ORDC), were previously presented by PJM in prior papers and stakeholder presentations. Updated explanations for each of these components are contained in this document. This document also details additional changes to the energy and reserve[2] markets that PJM believes are required to ensure a sustainable, robust Energy and Reserve Market design.

Issue Background

PJM brought this issue to stakeholders in 2017 with the first meeting of the Energy Price Formation Senior Task Force (EPFSTF) occurring in January 2018 to discuss the PJM proposals to enhance the Energy and Reserve Markets. At that time, implementation of ORDCs that aligned the prices for reserves with their reliability value and extended locational marginal pricing were the primary enhancements that motivated PJM to open this discussion with stakeholders.

In April 2018, the Board issued a letter[3] informing stakeholders that it had directed PJM management to prioritize the various issues under the scope of price formation. The letter was issued to recognize and address stakeholder concerns regarding the magnitude of the changes proposed by PJM and to drive the group to consensus on enhancements that could be implemented in the near-term to improve market performance.

The letter stated:

> *" … the Board has directed PJM management to identify those components of the reserve procurement and pricing issues that can be implemented for the winter of 2018/19. The Board respectfully requests stakeholders to deliberate timely and work to develop the details of market rule changes to address those components of the reserve procurement and pricing issues outlined above by the third quarter of 2018 such that the Board may direct a PJM Section 205 filing to implement those changes in time for the winter of 2018/19. The Board has further directed PJM management and requests stakeholders to continue work to*

[1] https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en

[2] For the purposes of this document, the term "reserves" refers to reserves used in real-time system operations, not those associated with the system planning process.

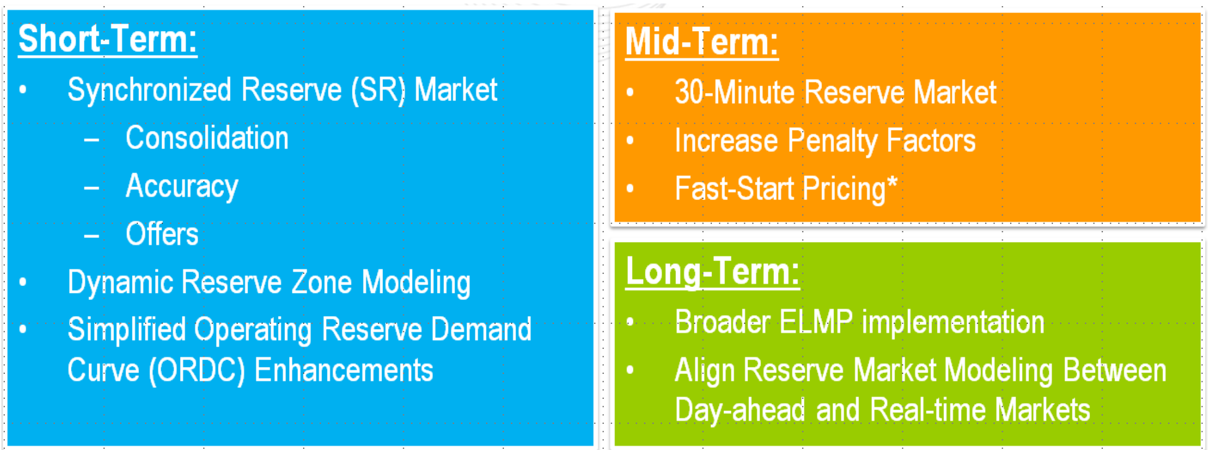
[3] https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/postings/20180412-pjm-board-letter-regarding-energy-market-price-formation.ashx?la=en.

develop the details of the remaining components of the reserve procurement and pricing issues by the first quarter of 2019 for Board action, filing with FERC and implementing the proposal by the summer of 2019."

In response to this direction, PJM management compiled Figure 1 below to categorize the various enhancements to be pursued under the price formation umbrella. This exhibit was shared with members at the April 18, 2018, EPFSTF and set the path forward for the group.

Enhancements identified in the "Short-Term" section were to be the immediate focus and were planned to be resolved for implementation for the winter of 2018/2019. The "Mid-Term" changes would be those that would meet the Board's timeline for implementation by the summer of 2019. The initiatives in the "Long-Term" section were those that PJM believed were important, but recognized may require more stakeholder deliberation.

Figure 1. Timeline for Stakeholder Discussion on Price Formation Enhancements



* Implementation dependent on FERC process and approval/rejection.

Despite meeting 10 times between the issuance of the letter and the end of the third quarter of 2018, the EPFSTF was unable to reach a vote on the changes listed in the "Short-Term" set. Because PJM felt that consensus may be able to be reached on the components in this category except for the ORDC, PJM extended the stakeholder process under the expectation that stakeholders would arrive at a vote at the EPFSTF on all items listed as "Short-Term" in the near future.

At the October 2018 meeting of the PJM Board, PJM provided a white paper detailing the reasons why the PJM-proposed "Short-Term" changes are required to ensure the market is functioning effectively. Those enhancements, which are explained in more detail below, focus on enhancing the reserve markets by more directly aligning the reliability value of reserves with the clearing price for them and strengthening incentives for performance when reserves are deployed.

Since the October 2018 meeting of the PJM Board, the EPFSTF has met three more times and cancelled a vote that was scheduled to occur following the Nov. 1, 2018, meeting. At this time, PJM does not believe there is a clear path to reaching a vote within the stakeholder process on all components contained in the "Short-Term" set. Given the pace of the EPFSTF discussions to date, PJM also believes that reaching consensus on the mid to long-term reserve pricing initiatives in a timely manner is unlikely. Therefore, PJM management has requested, and the Board has endorsed, the components of a comprehensive package and a timeline for action.

Background on the Evolution of PJM's Reserve Markets

PJM introduced reserve markets in late 2002 with the implementation of the Real-Time Synchronized Reserves Market. Prior to that time, reserves were assigned manually by system operators and paid at cost-of-service. While the market implementation represented a significant enhancement due to the migration from a cost-of-service provision to a market-based procurement, the design at this time was focused on procuring ancillary services to meet a defined requirement stipulated by entities like the North American Electric Reliability Council and not explicitly on maximizing operational efficiency or incentivizing flexibility.

In 2012, PJM implemented shortage pricing in response to Federal Energy Regulatory Commission (FERC) Order No. 719A. This set of rule changes was specifically targeted at enhancing rules for energy and reserve price formation during periods where PJM experienced reserve shortages.

Several enhancements were made to the Energy and Reserve Markets as part of this set of rule changes:

1. PJM changed its operating methodology. Initially, reserves were committed an hour ahead of time and energy was dispatched in real time around those reserve commitments. Now, a small set of reserve commitments are performed ahead of real time and the remaining need for reserves is jointly optimized with energy as part of the Security Constrained Economic Dispatch.
2. PJM implemented a Primary Reserve market to minimize the procurement cost and provide transparent pricing of total 10-minute reserves.
3. Reserve pricing was changed from an hour-ahead basis to being performed every five minutes, coinciding with the calculation of the locational marginal price (LMP).
4. PJM implemented reserve demand curves for the first time. These curves were (and still are) very rudimentary and narrowly focus on meeting a fixed requirement at less than or equal to a maximum price (i.e., the penalty factor).

Notwithstanding minor changes to the initial ORDCs implemented in 2012, the reserve market design and price formation in PJM has largely been unchanged since 2012.

PJM's Goals for Reserve Market Enhancements

PJM has proposed several significant market rule changes to ensure that the market is operating as efficiently as possible and that prices reflect the cost and value of the services being provided to the maximum extent possible. Below are several high-level goals that guide PJM's proposal.

While there are many implementation details that have been discussed with stakeholders and PJM's Independent Market Monitor (IMM), PJM's proposal is guided by these principles:

1. Reserve and energy prices reflect system conditions and appropriately value scarcity.
2. ORDCs reflect the reliability value of reserves.

3. The actual reserve capability on the system is accurately measured.
4. Resources assigned reserves will provide them when deployed.
5. Market power is mitigated.
6. Social welfare is maximized.[4]

Today, these goals are not always met. For example, energy and reserve prices do not always align with system conditions. This can occur for a number of reasons, including that the ORDCs in use today do not accurately reflecting the reliability value of reserves and the difficulty in determining the amount of reliable reserves on the system due to the voluntary nature of some synchronized reserves.

It can also be argued that under today's design, social welfare is not maximized because the ORDCs do not reflect the true value of reserves. PJM seeks to enhance the reserve market design by ensuring that its proposal will achieve these goals.

The Relationship Between the Capacity Market and Operating Reserve Markets

In its capacity market, PJM procures capacity on behalf of load to ensure that there are adequate resources available during the delivery year to meet energy and reserve requirements. Capacity market revenues are intended to ensure that resources have an opportunity to recover fixed costs that are not recovered through the Energy Market and Ancillary Services Market. The opportunity to recover variable operating costs is through the Energy and Reserve Markets and in some cases, uplift payments.

Throughout the day-ahead and real-time operating day, the reserve markets are tasked with procuring sufficient resources so that PJM can operate reliably given the inherent uncertainty on the system. This uncertainty includes, but is not limited to, uncertainty related to resource performance and near-term load forecast error. The reserve market clearing price is intended to reflect the marginal cost of maintaining those reserves in the same way the LMP reflects the marginal cost of producing energy. The primary marginal cost associated with providing reserves is lost opportunity cost. Lost opportunity cost is the revenue that a resource foregoes in the Energy Market by not generating in order to provide reserves. Capacity market revenues are not intended to cover these costs.

By capturing the lost opportunity cost in the reserve market clearing price, reserve markets also provide incentives for resources to lower their output and provide reserves instead of providing energy. Absent a payment for reserves, resources would not have the incentive to provide them because they could maximize revenues by providing energy instead.

[4] Maximizing social welfare is the objective function of the market clearing algorithms. The goal of this objective function is to optimally allocate resources for energy and reserves such that the final allocation simultaneously maximizes the benefit to consumers and the revenues to suppliers. This is done by maximizing the difference between the consumer's willingness to pay for a product and the bid production cost of cleared supply.

The relationship between the capacity market and reserve markets is one that has been raised during EPFSTF meetings. Specifically, the assertion has been made that PJM's objective is to replace the capacity market with an energy-only market and that the ORDCs PJM has proposed serve that purpose. Both of these statements are incorrect. PJM's objective is not to replace the capacity market. PJM's goal is to improve Energy and Reserve Market pricing. While PJM's proposed reserve market enhancements will indirectly affect the capacity market because they will likely result in increased Energy and Reserve Market revenues, there is no intent to replace the capacity market. Such an endeavor would require a much broader discussion and would necessitate the removal of price caps, which PJM is not proposing.

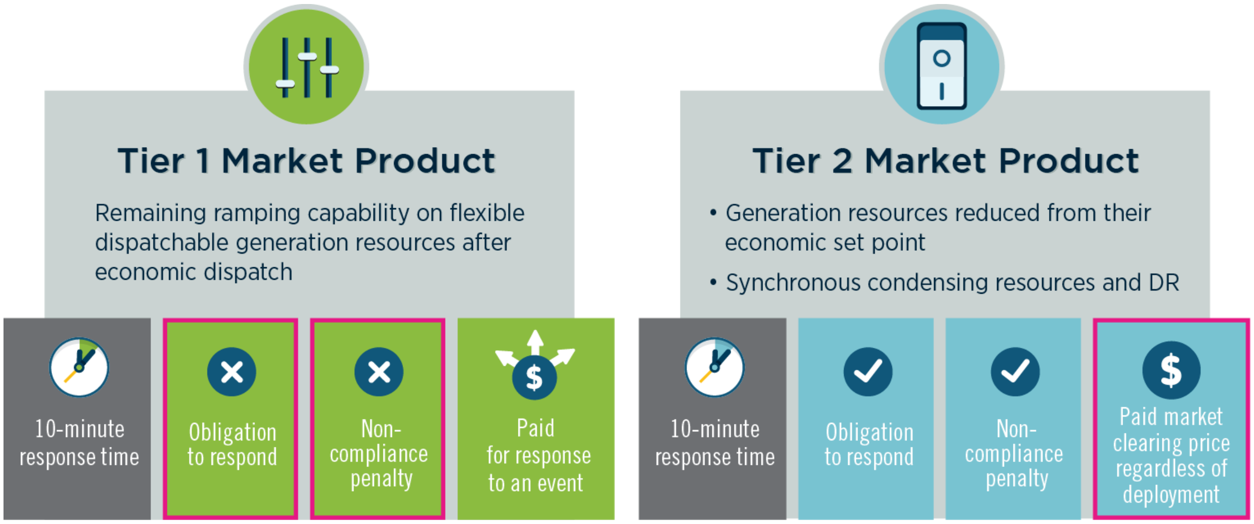
The ORDCs that PJM has proposed do not directly relate to the value of capacity. They convey the probability that PJM will not have enough reserves on the system to maintain its minimum reserve requirement given the inherent uncertainties associated with operating a power system. Nothing about these probabilities relates to the capacity market or is proposed with the intent to replace it. Although the Electric Reliability Council of Texas (ERCOT) has an energy-only market and has implemented ORDCs that are also based on expected uncertainty on their system, it is incorrect to presume that such curves are only appropriate in systems without a capacity market.

A Summary of PJM's Proposed Reserve Market Changes

Proposed Enhancement: Consolidation of Tier 1 and Tier 2 Reserve Products

Under PJM's current market rules there are two types of synchronized reserves, Tier 1 and Tier 2. Figure 2 provides a summary of the differences between these products.

Figure 2. Synchronized Reserve Market Product Descriptions



The combination of the Tier 1 and Tier 2 reserve products is used to meet the synchronized reserve requirement. The market clearing process assumes that all available Tier 1 reserve capability is free and it is counted toward the requirement first. If the requirement cannot be met solely by Tier 1, Tier 2 resources are cleared to meet the remainder of the requirement. If Tier 2 resources are assigned and there is a non-zero clearing price, only Tier 2 resources are paid the clearing price as they are the only resources that have an obligation to respond. Unlike Tier 1 resources, Tier 2 resources also face a noncompliance penalty if they are deployed and cannot meet their obligation. In 2017, on average, over 1,100 MW of the approximately 1,500 MW synchronized reserve requirement was met by Tier 1 resources, which have no obligation to respond in an event. Further, in approximately one-third of the hours of 2017, the entire synchronized reserve requirement was met solely by Tier 1 reserves.

PJM's proposed change is intended primarily to enhance the accuracy of PJM's reserve measurements and the reliability of response. In 2017, the average response rate of Tier 1 reserves was approximately 60 percent. From a reliability perspective, this response rate is unacceptable and clearly indicates an incentive problem in the market. Tier 2 reserve response rates were nearly 90 percent in 2017 and have dropped to close to 75 percent in 2018. The proposed change will also decrease market complexity and remove an inequity in compensation between Tier 2 and Tier 1 reserves that do reliably respond when deployed.

PJM believes that consolidating the Tier 1 and Tier 2 reserve products into one uniform synchronized reserve product modeled after the Tier 2 product will solve multiple issues that exist in the reserve markets today.

This unified product will:

1. Be assigned based on the market solution that maximizes social welfare
2. Be obligated to respond based on the assigned quantity
3. Be compensated at the applicable clearing price for the assigned megawatt amount
4. Face the existing penalty if the resource does not respond during an event

By applying these standards across all synchronized reserve resources, PJM expects the following benefits:

1. More accurate reserve calculations that require less operator intervention
2. More reliable reserve assignments that will improve synchronized reserve performance
3. Consistent compensation for all resources providing the same service
4. More accurate energy and reserve pricing due to improved synchronized reserve measurements

In addition to these enhancements, PJM has proposed several other market rule changes that apply to the offer structure and capability for synchronized reserve products. These additional changes are summarized in the table below. PJM has worked with the IMM to develop many of these improvements.

Figure 3. Proposed Market Rule Changes for Synchronized Reserves

Current Rule	Proposed Rule	Rationale
Offers for Tier 2 synchronized reserve are capped at variable operations and maintenance (VOM) costs plus a $7.50/MWh margin adder.	Offers for synchronized reserves will be capped at the expected value of the synchronized reserve penalty. This will be calculated periodically as system conditions change and will consider the average value of the penalty in $/MWh, the average performance of synchronized reserve resources when deployed, and the probability of an event occurring.	Resources providing synchronized reserve do not incur additional VOM costs beyond those already included in their Energy Market offer VOM costs. VOM costs should therefore be excluded from reserve market offers The goal of the reserve market design is to ensure that resources on the margin are indifferent to providing reserves or energy. Allowing participants to express the risk they assume by accepting an obligation via the synchronized reserve offer is key to ensuring they are indifferent. However, the $7.50/MWh level that is currently in place is arbitrary and well above current estimates of the expected value of the penalty, which are approximately $0.02/MWh. Rather than setting the cap to a static $0.00/MWh based on current conditions, reassessing the cap on a periodic basis will allow the cap to change as clearing prices, and consequently the expected value of the penalty, are ultimately impacted by the proposed reserve market enhancements.
The reserve capability of a resource is based on its offered capability into the reserve market.	The reserve capability of a resource is based on its ramping capability in the Energy Market and the reserve type being procured (10-minute reserves or 30-minute reserves).	Currently asset owners must maintain two sets of data, Energy Market offer data and reserve market offer data, which are intended to reflect the ramping capability of a resource. The reserve market data is not maintained as accurately as Energy Market offer data and leads to imprecise reserve calculations. Using Energy Market offer data to determine reserve capability will improve accuracy.

Proposed Enhancement: Locational Reserve Requirements

Under today's market rules, PJM models the Mid-Atlantic and Dominion Reserve Zone. This reserve zone has its own requirement, which can be met by either reserves within the zone itself or with reserves that can be imported from the rest of PJM. The ability to import reserves into the area is determined by the most limiting interface between the rest of PJM and the Mid-Atlantic and Dominion Reserve Zone. For example, if the Mid-Atlantic and Dominion requirement is 1,000 MW and there are only 300 MW of available flow on the limiting interface, 700 MW of reserves will need to be committed within the Mid-Atlantic and Dominion Reserve Zone to ensure that no more than 300 MW of energy flows on the limiting transmission interface during a reserve deployment. Other ISO/RTOs use similar reserve zone modeling.

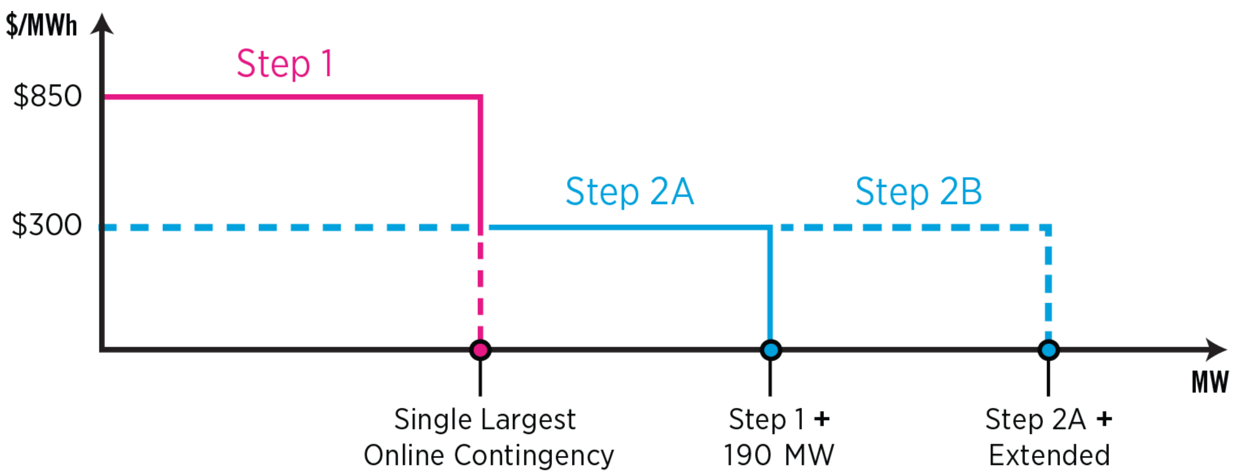
As a long-term objective, PJM is researching moving to a nodal reserve market. PJM believes a nodal model would be the most optimal and could lead to significant improvements in the accuracy of reserve assignments. However, evolving from a regional model to a nodal one is a significant enhancement that will require time to develop. Currently, no markets in the United States, or internationally to PJM's knowledge, implement nodal reserve market designs. While development on this model continues, PJM is proposing to expand the existing static reserve zone model so that there are more predefined reserve zones that can be swapped in or out on a more frequent basis to better align the reserve market model with operational needs as the limiting transmission interface changes. PJM believes that the optimal frequency to change the predefined reserve zone would be as frequent as operationally needed, but given the administrative complexity of this model, daily changes to the reserve zone are more realistic. PJM plans to use the proposed, more flexible, zonal model for the foreseeable future, unless and until a nodal reserve market model could be designed, developed and implemented.

Proposed Enhancement: Implement Operating Reserve Demand Curves

Today PJM uses penalty factors to determine the maximum willingness to pay for reserves and ultimately set energy prices during shortage conditions for both synchronized and primary reserves. The current demand curve for synchronized reserve is shown in Figure 4. The synchronized reserve megawatt demanded in the red portion of the curve, labeled Step 1, are determined by the real-time megawatt output of the single largest online contingency. This quantity criterion is the minimum reserve requirement and has been in place since 2012, when shortage pricing was implemented. The price of Step 1, $850/MWh, is based on analysis of the out-of-market make-whole payments made for reserves from an operating event in 2007.

The blue portions of the synchronized reserve demand curve, Steps 2A and 2B, were both added more recently (in 2017 and 2014, respectively). Step 2A was implemented in response to FERC's order that PJM implement transient shortage pricing. The purpose was to add a smaller step on the curve to avoid system volatility due to large swings in price for small changes in reserve amounts that would have occurred with just Step 1. Step 2B was added as a result of a package that was approved by PJM members that originated in the Energy and Reserve Pricing and Interchange Volatility special sessions of the Market Implementation Committee. The purpose of this optional step was to create the ability to extend the reserve requirement when PJM operators took actions to schedule additional reserves during conservative operations. To date, this step has not been used.

Figure 4. Current Synchronized Reserve Demand Curve



Steps 2A and 2B are both priced at $300/MWh. This value is based on analysis of the offers of quick-start resources at the time that Step 2B was added in 2014.

Under today's operating practices, PJM does not explicitly schedule flexibility beyond the requirement expressed on the Step 2A of the demand curve. This flexibility typically exists on the system due to the types of resources in PJM and is used by operators when it is available and needed. However, it is not accounted for in scheduling and not explicitly valued in the reserve markets. If there is no uncertainty on the system, this model can work properly and result in an accurate value for reserves and energy. In the existence of uncertainty, like that which exists on all power systems, this methodology falls short of acquiring enough reserves to manage that uncertainty and fails to accurately assign a value to reserves and energy.

The market models in place today for energy and reserves assume that the power system operates with a degree of precision that it physically cannot. These models commit and dispatch resources to meet energy and reserve needs, and determine market clearing prices, under the assumptions that the forecasted state of the system is known and that all resources operate as indicated by their offer data. These assumptions are not correct, and therefore system operators cannot follow all operating instructions from the market clearing tools. The required manual intervention by operators adds either energy or reserve supply on the system that is not valued by the market systems resulting in suppressed prices.

There are several ways to address this issue:

1. **Improve forecast and resource offer data.** This is always a goal of PJM's, but it will never be perfectly accurate.
2. **Implement a stochastic commitment, dispatch, and market clearing engines.** Stochastic optimization models consider multiple potential future outcomes and weigh them based on probabilities. The result of these models produces a resource dispatch and a set of prices that reflect the most likely outcome. Stochastic optimization models are currently still under development and not implemented in any markets. Once fully developed, these models may be ideal for systems with a high degree of uncertainty such as those with high renewable penetrations.
3. **Enhance reserve market modeling to reflect uncertainty.** This is what PJM is proposing via the ORDCs. These curves recognize that additional flexibility is needed on the system beyond what the market models traditionally value. This ensures that system operators have enough resources available in the short-term to meet energy and reserve need given historic levels of forecast uncertainty and reduces their reliance on manual intervention to help maintain reserves.

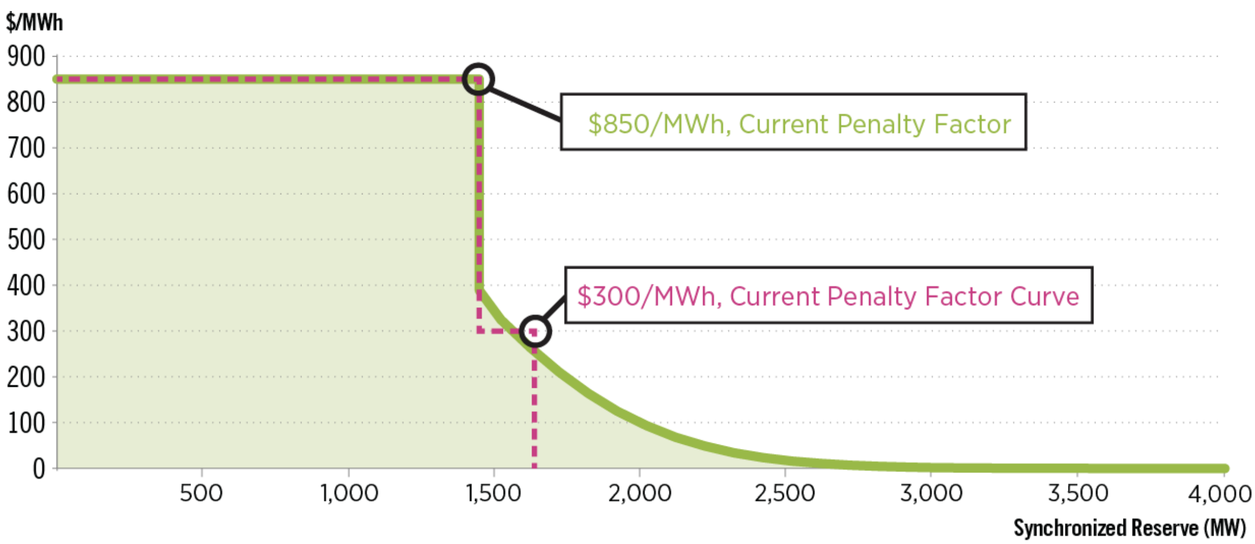
PJM believes that enhancing its reserve market design, and specifically implementing ORDCs, will be a significant improvement to align the market models with actual system operations. The current demand curves are not sufficient because they suffer from the following drawbacks:

1. **The curves do not value reserves highly enough.** In operations today, PJM will take actions in excess of $850/MWh to maintain both synchronized and primary reserves. Actions such as calling on generators with costs above $850/MWh and up to $2,000/MWh, deploying pre-emergency and emergency demand response with offers in excess of $1,800/MWh, and initiating a voltage reduction action, which has the effect of reducing load, are taken to preserve the reserves up to the current requirement. Any time PJM takes an action to maintain reserves at a cost above the $850/MWh level, reserve prices cannot reflect the cost of reserves because the current demand curves will not let prices exceed that level.

2. **Reserves beyond the identified requirements are not accurately valued.** Reserves in excess of the currently defined requirements increase system reliability because they allow the system to quickly respond to additional uncertainty beyond the loss of the largest unit, such as load forecast error, renewable generation forecast errors, and so on. This capability is not accurately valued today and PJM believes it should be recognized.

To address these drawbacks, PJM proposes replacing the current synchronized and primary reserve demand curves with downward sloping ORDCs and raising the highest point on these demand curves from $850/MWh to $2,000/MWh. The revised ORDC incorporates the minimum reserve requirement in existence today, but extends the current curve to include reserves greater than the minimum reserve requirement such that additional reserves are both scheduled and valued when it is rational to do so. Figure 5 shows the current synchronized reserve demand curve as a red dotted line compared to a downward-sloping ORDC with the same penalty factor level of $850/MWh.

Figure 5. Example of a Downward Sloping Operational Reserve Demand Curve



The downward-sloping portion of the ORDC is derived by measuring the average uncertainty on the system and also taking into account its volatility. For the ORDC in Figure 5, PJM calculated the load forecast error, solar and wind generator forecast error, and generator performance uncertainty over a three-year period based on 30-minute-ahead forecasts. Each of these errors has an average and a standard deviation associated with it to define its distribution. These three distributions are then combined together into a single distribution that determines the average and variability of the uncertainty on the system. Using this information, PJM can then determine the probability of falling short of the minimum reserve requirement given a level of reserves being procured.

To determine the price points on the curve in Figure 5, the probability of falling short of the minimum reserve requirement are multiplied by the penalty factor, $850/MWh in this example. Multiplying the probability times the penalty factor price of $850/MWh results in the expected cost of a reserve shortage in the future and therefore determines what consumers should be willing to pay to avoid it.

For example, if there is a 10 percent chance of a reserve shortage occurring in 30 minutes, and that reserve shortage will cost $850/MWh, a consumer would be willing to pay $85/MWh to procure more reserves to avoid the future shortage. Once this initial curve is constructed, a final step is taken, which is to subtract the regulation requirement megawatts from each point on the ORDC. This is done to recognize that regulation, another ancillary service in PJM, is also used to respond to uncertainty on the system. In fact, regulation is often the first line of defense to respond to uncertainty because it is deployed using an automatic control signal and has a shorter response time (five minutes) than synchronized reserves (10 minutes). The regulation requirement varies between 525 MW and 800 MW depending on the hour of the day. PJM assumed a 525 MW regulation requirement to calculate the ORDC shown in Figure 5.

By using the regulation requirement to shift the ORDC as PJM proposed, an assumption is made that the full amount of regulation capability is always available. At the November 28, 2018, EPFSTF meeting, members provided feedback that using the regulation requirement to adjust the ORDC could misrepresent the amount of regulation available to respond due to uncertainty in the availability of regulation in the up direction. PJM is performing more analysis on the regulation signal by studying historic regulation data to determine if there is a better method to more accurately account for regulation in the ORDC. More information on this enhancement will be provided at subsequent EPFSTF meetings.

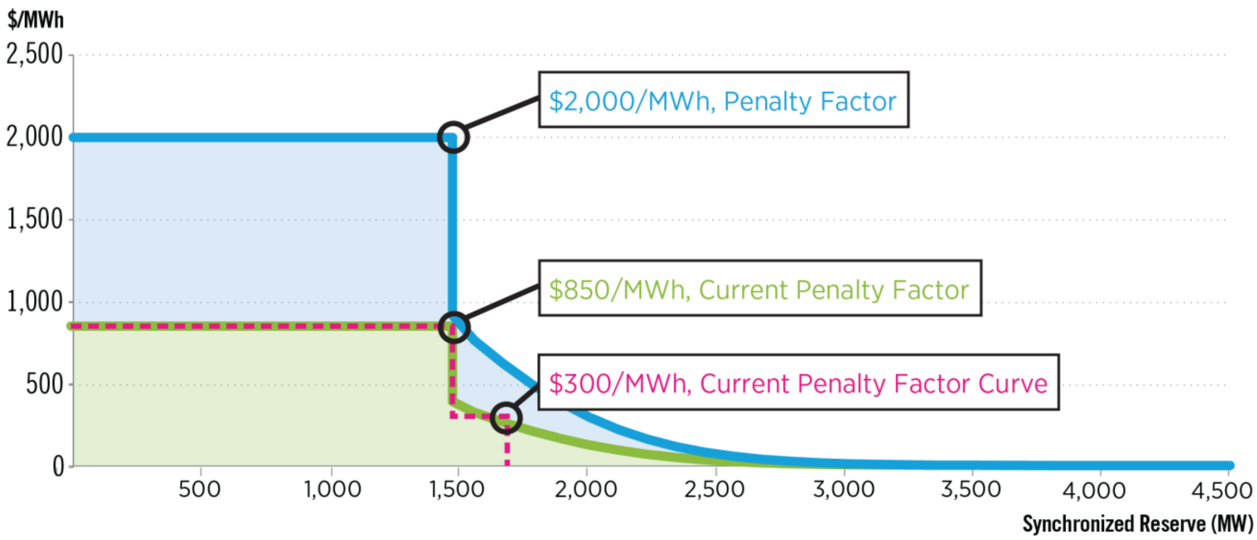
PJM has proposed a set of 24 ORDC curves for each reserve product for use during the year. The curves are calculated for six time blocks during the day for each season of the year. The purpose of using different curves for different times of the day and seasons of the year is that the uncertainties that were measured to create the curves change based on the time of day and season of the year. For example, load forecast error tends to be lower on a warm summer day than it does during an extremely cold winter day. To capture these changes, PJM has proposed multiple ORDCs for all reserve products.

To illustrate how the ORDCs function, consider a scenario where PJM schedules supply to meet forecasted load and its minimum reserve requirement of 1,450 MW of synchronized reserves; also assume that all generators perform as scheduled. If the load forecast is perfect, PJM's minimum reserve requirement is met without issue. However, if the actual load is 200 MW above the forecast, additional resources are required to meet the 1,450 MW synchronized reserve requirement and serve the additional 200 MW of system load. If this additional flexibility is not available on the system and ready to be deployed, it can result in the inability to meet the minimum reserve requirement and lead to shortage pricing, or, result in an out-of-market action by the system operator.

Based on the ORDC shown in Figure 5, the probability of not meeting the minimum reserve requirement of 1,450 MW in 30 minutes when 1,650 MW are available is approximately 31 percent. When viewed with respect to the forecast data, it can be translated that there is a 31 percent chance that the combined forecast errors for load, solar and wind, and thermal generator performance will be greater than or equal to 200 MW. If the maximum willingness to pay to meet the minimum reserve requirement is $850/MWh, then it follows that the willingness to pay for 200 MW of additional reserves, or 1,650 MW, to prevent a shortage of the minimum reserve requirement would be ($850/MWh * 31 percent), or approximately $263.50/MWh. Similarly, at 2,000 MW of reserves, there is an 11 percent chance that in 30 minutes the uncertainty on the system will exceed 550 MW and PJM will not be able to meet its minimum reserve requirement. Therefore, the willingness to pay for 2,000 MW of reserves is ($850/MWh * 11 percent), or about $93.50/MWh.

PJM believes that the ORDC methodology is an intuitive, straightforward, way to align the reliability value of reserves with the price. However, to ensure that prices can reflect all actions that system operators are willing to take to maintain reserves, it is important that the penalty factor be set high enough so that prices can reflect those actions. Currently, PJM system operators will take actions in excess of $2,000/MWh to maintain reserves such as purchasing emergency energy from neighboring areas. However, FERC has implemented a cap of $2,000/MWh on all offers that are eligible to set price. These high-cost actions include the deployment of generators with offers up to $2,000/MWh and the deployment of other expensive resources such as emergency demand response. To ensure that the reserve and energy prices can reflect these actions and not be artificially suppressed, the penalty factors for synchronized and primary reserves must be increased from $850/MWh to $2,000/MWh. Any lower penalty factor will result in reserve and energy prices that are suppressed during tight system conditions and scarcity pricing signals that are muted. Raising the penalty factor will result in a "shift up" of the ORDC by a factor of about 2.3 such that the final synchronized reserve ORDC would be the blue curve shown in Figure 5.

Figure 6. Comparison of Operating Reserve Demand Curves for synchronized reserves



PJM believes that adopting the proposed methodology to construct ORDCs for synchronized and primary reserves will have the following benefits:

1. Reserves in excess of the minimum reserve requirement will be appropriately valued based on their benefit to system reliability.

2. PJM will assign additional reserves, when economic to do so, that will result in fewer instances when 1) system operators take out-of-market actions to maintain reserves and 2) the minimum reserve requirement is not met and reliability is degraded.

3. Reserve prices will be able to reflect all system operator actions taken to maintain reserves up to the $2,000/MWh penalty factor.

Proposed Enhancement: Align Reserve Products Between Day Ahead and Real Time

In the current market model, PJM operates a 30-minute reserve market, the Day-Ahead Scheduling Reserve Market, that is co-optimized with the Day-Ahead Energy Market, and 10-minute reserve markets that are co-optimized with the Real-Time Energy Market. PJM's initial implementation of its real-time, 10-minute reserve market occurred initially in December 2002, and then was enhanced in 2012 with shortage pricing. The implementation of the 30-minute reserve market in the Day-Ahead Energy Market occurred in June 2008 as a result of a settlement agreement reached by members on the Reliability Pricing Model (RPM). Originally, the RPM proposal contained requirements that capacity resources meet specific operating characteristics, such as the provision of 30-minute reserve capability. During settlement discussions between PJM stakeholders on the RPM proposal, that component was taken out of the RPM and the Day-Ahead Scheduling Reserve Market was implemented in its place.

Clearing 30-minute reserves in the day ahead and not maintaining or valuing that product in real time creates a modeling discrepancy between the day-ahead and real-time markets. This occurs because the imposition of a requirement for 30-minute reserves in the Day-Ahead Energy Market will impact the commitment and dispatch of resources in the Day-Ahead Energy Market and ultimately influence both reserve and energy prices. In the Real-Time market, the megawatts scheduled as 30-minute reserves are viewed as no longer needed as reserves and can then be converted into energy with no consequence. This results in an injection of supply into the Real-Time Energy Market that was held in the Day-Ahead Energy Market as reserves and therefore creates commitment, dispatch, and price discrepancies between the markets. These price discrepancies can be arbitraged by virtual transactions without adding value back to the market because the discrepancy was driven by a modeling difference. In real time, the same scenario occurs, but in the opposite direction because 10-minute reserves are procured in real time, but not in the Day-Ahead Energy Market.

Based on the current market rules, the average requirement for 30-minute reserves in the Day-Ahead Energy Market is 5,600 MW per hour and the average requirement for 10-minute reserves in the real-time market is about 2,200 MW per hour. At a high level, these two reserve requirements likely offset each other to some extent. However, given that the products are different and the resources that can provide the different products may also be different, there is no direct offset or guarantee that the resources procured to meet reserves in the Day-Ahead Market will be the same resources that provide reserves in the Real-Time Market.

Absent better alignment, PJM's proposed ORDCs would further exacerbate the existing discrepancy between the day-ahead and real-time markets. This is because the proposed ORDCs will result in PJM procuring more reserves for the system because they have a benefit to addressing system uncertainty. This will widen the gap that exists today which is created by the misalignment of reserve market models. While PJM has discussed aligning the reserve markets between day-ahead and real-time in the past, PJM believes that now is the appropriate time to make such a change. PJM therefore proposes to add 10-minute reserve markets to the Day-Ahead Market and a 30-minute reserve market to the Real-Time Market. Doing so will ensure that the Day-Ahead and Real-Time Energy Market models are aligned, eliminate false arbitrage opportunities that result from these modeling differences, and ensure there are no unintended consequences from implementing the proposed ORDCs that stem from this lack of alignment.

To ensure consumers do not pay twice for reserves, PJM plans to implement a full balancing settlement for all reserve products. In the same way energy quantity deviations between day-ahead and real-time and settled at the real-time price, reserve deviations between day-ahead and real-time would be settled at the corresponding real-time reserve price. This has the additional benefits of allowing loads to hedge some or all of their reserve costs in real-time by procuring them day-ahead and also strengthens incentives to provide reserves in real-time. In real time, adding a 30-minute reserve market will fill an existing gap in the market design. As stated previously, PJM system operators rely on 30-minute flexibility to respond to forecast error, backfill 10-minute reserves once deployed, and recover from larger losses of resources that could result from a contingency on the gas network. Today this flexibility is not valued in the market.

Figure 7. Example Operating Reserve Demand Curves for 30-Minute Reserves

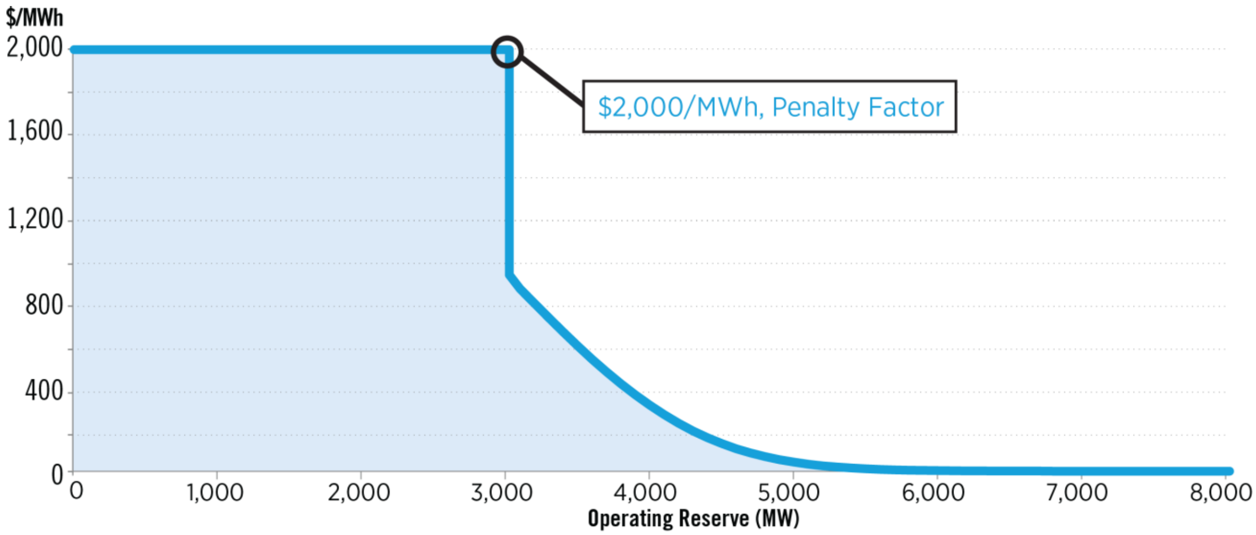


Figure 7 provides an example of the ORDC that PJM is proposing for 30-minute reserves in the day-ahead and real-time markets. This curve was created using the same methodology of statistical uncertainty that was used for the 10-minute reserve product ORDCs. This curve incorporates a $2,000/MWh penalty factor, a minimum reserve requirement of approximately 3,000 MW, about 2 times the largest unit on the system, and a downward-sloping section that is calculated using the 60-minute forecast uncertainty for load, interchange, wind and solar generation, and anticipated thermal generator performance, given the longer-term nature of the 30-minute reserve product compared to energy. The curve shown in Figure 7 also features a shift by the regulation requirement like the 10-minute ORDCs.

PJM is proposing a $2,000/MWh penalty factor for 30-minute reserves as well due to the fact that PJM operators will dispatch all economic generation to maintain 30-minute reserves. Because offers for those resources can reach $2,000/MWh, PJM believes that this is an appropriate penalty factor to ensure PJM's dispatch tools take all necessary actions to maintain 30-minute reserves and those actions are reflected in prices. The simulation results provided in this document were performed with a penalty factor of $500/MWh, not $2,000/MWh. Given the extremely low average clearing prices of the 30-minute reserve market, PJM does not anticipate changing this parameter will have a meaningful impact on the overall simulation results.

To minimize the modeling differences between the Day-Ahead and Real-Time markets, PJM plans to implement identical ORDC curves in the Day-Ahead and Real-Time markets for each of the 10-minute and 30-minute reserve products.

Proposed Enhancement: Transition Energy and Ancillary Services Offset Mechanism

The Energy and Ancillary Services Offset is calculated by PJM prior to each RPM Base Residual Auction (Auction) to estimate the average energy and ancillary services net revenues that the reference unit will collect in the delivery year for which the Auction is being executed. This value is subtracted from the gross cost of new entry to determine net cost of new entry, which is then used to construct the demand curve for the Auction.

The Energy and Ancillary Services Offset is calculated using Energy Market results from the three calendar years preceding the Auction. For the upcoming 2022/2023 Auction that will be run 2019, the Energy Market results from the calendar years 2016, 2017, and 2018 will be used. This means that the actual Energy Market revenues for 2016, 2017, and 2018 will be used to estimate Energy Market revenues in 2022/2023.

Should PJM's energy and reserve price formation enhancements be approved, an historic Energy and Ancillary Services Offset would likely underestimate future Energy and Reserve Market revenues considering that PJM's proposal will likely result in increases in the energy and reserve prices compared to the historic values. To account for this expectation, PJM has proposed a transition mechanism that will estimate Energy and Ancillary Services revenues as if PJM's proposed Energy and Reserve Market rule changes had been in place.

PJM proposes to simulate the Energy and Reserve Market outcomes based on actual operating conditions, but with the proposed reserve market modifications once accepted by FERC. This simulation will be conducted in the same manner PJM simulated market results to measure the impact of its proposed changes. Using this methodology, the E&AS Offset would remain a historic calculation, but be calculated in such a way that it would reflect the additional energy and reserve revenues expected based on the proposed reserve market changes.

Figure 8 provides an example of how PJM's Energy and Ancillary Services Offset proposal would work if PJM's proposal is approved by FERC prior to the 2022/2023 Auction in August 2019 and is implemented on June 1, 2020, coinciding with the beginning of the 2020/2021 delivery year. Assuming that the proposed changes are implemented mid-year in 2020 for the sake of this example, half of that year will need to be simulated to take into account the energy and reserve revenue changes and half of it will be captured in the actual results.

Figure 8. Example Scenario for Proposed Energy and Ancillary Services Offset Calculation

Auction Execution Date	Delivery Year	Revenue Year	Revenue Calculation
August 2019	2022/2023	2016	Simulated
		2017	Simulated

Auction Execution Date	Delivery Year	Revenue Year	Revenue Calculation
		2018	Simulated
May 2020	2023/2024	2017	Simulated
		2018	Simulated
		2019	Simulated
May 2021	2024/2025	2018	Simulated
		2019	Simulated
		2020	Half Simulated + Half Actual
May 2022	2025/2026	2019	Simulated
		2020	Half Simulated + Half Actual
		2021	Actual
May 2023	2026/2027	2020	Half Simulated + Half Actual
		2021	Actual
		2022	Actual
May 2024	2027/2028	2021	Actual
		2022	Actual
		2023	Actual

This methodology will result in an enhancement to the Energy and Ancillary Services Offset so that it better reflects expected energy and reserve revenues in the delivery year. At this time, PJM is not proposing any revenue adjustments to capacity auction results for delivery years that have already been cleared. PJM recognizes the concern with this approach but believes augmenting the results of cleared capacity auctions would be extremely disruptive to the market and result in justified complaints from capacity suppliers.

Estimated Impacts of PJM's Reserve Market Proposal

Increases in Potential Maximum Prices for Energy and Reserves

As a result of the changes in the ORDCs proposed by PJM, the maximum prices that are achievable during stressed system conditions will increase. This will occur for three reasons.

1. In the current design, PJM implements a form of price-cutting that does not allow the simultaneous additivity of the penalty factors by product and location. PJM is proposing to remove this price-cutting.

2. The introduction of a new 30-minute reserve market in day-ahead and real-time that will be co-optimized with energy.

3. The use of a $2,000/MWh penalty factor for all products.

While the maximum prices will increase, it is important to note that reaching significantly elevated pricing levels is extremely unlikely. Historically, PJM has only experienced several periods where shortage pricing has occurred, and, under its new proposal, will be procuring additional reserves to mitigate the uncertainty that can be a driver of these shortage pricing events. PJM's proposal will result in higher prices during shortages due to the increase in the penalty factors, however, accurate pricing during these periods is extremely important in sending the appropriate pricing signals, incentivizing behavior, and reducing uplift.

The price-cutting process in place today was implemented in 2012 with shortage pricing as a safeguard against the concern of many events where energy prices could rise higher than they had been in the past. It is designed to remove the ability for the simultaneous additivity of the penalty factors across products (Synchronized and Primary Reserves) and locations (the RTO and the Mid-Atlantic and Dominion reserve zone). With price-cutting in place and with simultaneous shortages across all products in all locations, the maximum energy price, notwithstanding the impacts of congestion and losses, is $3,700/MWh. Without price-cutting, the maximum price would be $5,400/MWh.

PJM believes it is important to construct these ORDCs such that the price of any particular product in any particular location accurately reflects the value of that product, especially in cases where the system is short a product in a given location. Constructing each ORDC in this manner, and then co-optimizing the three reserve products along with energy, will result in maximum energy prices higher than what can be reached today. Although the ORDCs create the hypothetical possibility of prices reaching these levels, it is important to note that PJM does not anticipate that this situation will occur. This is not only because historical experience has demonstrated that these conditions are unlikely to occur, but also because the implementation and maintenance of a real-time 30-minute reserve requirement will lead to the procurement of additional reserves that will assist in staving off shortages of the 10-minute reserve products. As noted earlier, PJM also has a capacity market that further incentivizes resource investment and therefore believes that sufficient resources will be available on the system to prevent a simultaneous shortage of all three reserve products across the entire system.

Energy and Reserve Market Simulations

To simulate the market and consumer impacts of PJM's reserve market proposal, PJM utilized the Perfect Dispatch application, with modifications, to simulate the impacts of PJM's proposed changes on the real-time markets for energy and reserves. This simulation was performed for the period of June 1, 2017 through May 31, 2018.

Because the Perfect Dispatch software is provided by PowerGem and has some simplifications compared to PJM's production software, which is provided by General Electric, PJM first executed a base case using the Perfect Dispatch software under the current set of market rules, with the exception that the Tier 1 and Tier 2 reserve products were consolidated into a single product. This change was included in the base case in this analysis due to a software limitation. However, considering that the estimated increase in costs of consolidating the Tier 1 and Tier 2 reserve products is less than $8 million over that period, the impact of that proposal was not considered as significant relative to the overall impact of PJM's changes.

Although PJM proposes to implement the proposed changes in both the Day-Ahead and Real-Time Reserve markets, PJM has only simulated the impacts on the real-time market due to software limitations that prevent simulating the day-ahead impact. However, given the better alignment the proposed changes will bring to the Day-Ahead and Real-Time markets, and the fact that day-ahead and real-time prices generally converge over time, PJM believes that simulating the Real-Time Market outcomes should reasonably quantify the overall market impacts to both the Day-Ahead and Real-Time markets. In addition, PJM allowed the simulation to perform a full recommitment of all resources, similar to what occurs in the day-ahead market clearing. This allows the simulation to better take into the account the effect of the alignment of the Day-Ahead and Real-Time reserve markets would have on day-ahead resource commitment.

The simulation results provided in this document were performed with a penalty factor for 30-minute reserves of $500/MWh, not $2,000/MWh. Given the extremely low average clearing prices of the 30-minute reserve market, PJM does not anticipate changing this parameter will have a meaningful impact on the overall simulation results. In the simulations performed by PJM, the following configurations were made to the base case and the simulation case.

Figure 9. Base Case Versus Simulation Case Differences for Price Formation Simulations[5]

		Base Case	Simulation Case
Real-Time Reserve Market	30-Minute	Not Modeled	Modeled with ORDC + $ 500/MWh Penalty Factor
	10-Minute	Status Quo	Modeled with ORDC + $2,000/MWh Penalty Factor
Reserve Offer Prices	10-Minute	As submitted	Set @ $ 0.00/MWh
	30-Minute	Not Applicable	Set @ $ 0.00/MWh
Locational Reserve Requirements	10-Minute	Not Modeled	Not Modeled
Resource Commitment		Recommitment of fast start units only	Full recommitment of all resources
Energy Market Offers		As submitted	As submitted

[5] At the time this simulation was performed, PJM assumed a level of $500/MWh as the penalty factor for 30-minute reserves. At the current time, PJM believes that the penalty factor for 30-minute reserves should be consistent with all other products at $2,000/MWh.

Energy and Reserve Market Simulation Results

To measure the impact of PJM's proposed changes, PJM measured changes to the following variables:

Figure 10. Energy and Reserve Market Simulation Results[6]

Variable	Base Case	Simulation Case	Difference
Weighted LMP ($/MWh)	31.24	33.51	2.27
Energy Revenues ($ millions)	24,800	26,600	1,800
Weighted SRMCP ($/MWh)	2.36	8.21	5.85
Weighted NSRMCP ($/MWh)	0.99	3.97	2.99
Weighted ORMCP ($/MWh)	N/A	0.001	0.001
Hourly Average Cleared SR (MW/hour)	2,075	2,964	889
Hourly Average Cleared NSR (MW/hour)	1,215	749	-466
Hourly Average Cleared OR (MW/hour)	N/A	2,828	2,828
Total Cleared SR (millions MWh)	18.2	25.4	7.4
Total Cleared NSR (millions MWh)	10.6	6.4	-4.2
Total Cleared OR (millions MWh)	N/A	24.2	24.2
Reserve Revenues ($ millions)	40	230	190
Uplift ($ millions)	160	90	(70)
Total Energy and Reserve Market Revenues ($ millions)	25,000	26,920	1,920

As seen in Figure 10, the analysis PJM has performed shows that the proposed reserve market design will result in an increase in Energy and Reserve Market revenues of approximately $1.92 billion. This is composed of an increase in energy revenues of about $1.8 billion due to an average increase in the LMP of $2.27/MWh and a $190 million increase in reserve revenues largely due to the implementation of the ORDC. The simulations also show a decrease in uplift of approximately $70 million, however, a portion of that reduction can be explained by the simulation software performing the unit commitment with perfect foresight into the actual operating conditions because of the nature of the simulations. Determining the exact proportions would be difficult and require more analysis.

Capacity Market Simulations

To complete the picture with respect to total changes in wholesale costs as a result of PJM's proposal, PJM also simulated the impact of the increased energy and reserve revenues on capacity market results. Figure 11 illustrates the impacts on the capacity market resulting from the increased Energy and Reserve Market revenues. There were two components to the impact of the increased energy and reserve revenues on the capacity market results:

[6] The Hourly Average Cleared Synchronized Reserve and Non-Synchronized Reserve (MW/hour) and the Total Cleared Synchronized Reserve and Non-Synchronized Reserve were taken from the actual Real-Time Market results and not the simulated base case. This was done because the base case simulation did not recognize the distinction between Tier 1 and Tier 2 reserves and therefore reported values that were not calculated consistently with current market rules.

1. A reduction in the net cost of new entry (Net CONE) value that forms the basis for the variable resource requirement (VRR) curve. This was estimated at $280 million.

2. Estimated reductions in capacity market offers resulting from increases in energy and reserve market revenues. Savings of this nature will be dependent on bidding behavior.

PJM conducted several simulations of the capacity market results using combinations of these two effects. As shown in Figure 11, the minimum simulated reduction in capacity payments of $440 million occurs with a shift in the VRR curve with an average supply offer reduction of $5/MW-day. The maximum simulated reduction in capacity payments resulted from the combination of the VRR curve shift and the entire average increase in energy and reserve revenues of $30/MW-day applied as a reduction in supply offers into the capacity market. This creates a range of potential capacity market cost reductions between $440 million and $1.5 billion.

Figure 11. Capacity Market Simulation Results

	Scenario 1	Scenario 2	Scenario 3
Savings Due to Reduction in Net CONE ($ millions)	280	280	280
Assumed Capacity Market Offer Reduction ($/MW-day)	5.00	10.00	30.00
Savings from Offer Reduction and Reduction in Net CONE ($ millions)	440	640	1,500

As described previously, the capacity market utilizes a three-year, rolling average of energy and reserve revenues to determine the net cost of new entry value used to set the VRR curve. Absent PJM proposed enhancement to simulate energy and reserve market revenues to determine the Energy and Ancillary Services Offset, the savings associated with a reduction in the net cost of new entry would take several years to fully occur. PJM's proposal would result in these cost savings occurring in full in the next Auction. The savings associated with a reduction in capacity supply offers would likely be realized more gradually over a three-year period as resources owners actually realize the anticipated revenue increases.

Total Impact on PJM Market Billing

Based on the analysis provided in Figure 10, PJM estimates that its proposal will increase Energy and Reserve Market revenues by approximately $1.92 billion. However, there will be an offsetting effect from the capacity market that ranges between about $440 million to $1.5 billion as shown in Figure 11. Figure 12 combines these two affects to provide a net impact to PJM billing.

Figure 12. Net Impact to PJM Market Billing

Net Cost Impacts			
	Scenario 1	**Scenario 2**	**Scenario 3**
Increase in Energy and Reserve Market Costs ($ millions)	1,920	1,920	1,920
Capacity Market Cost Reduction ($ millions)	440	640	1,500

Net Cost Increase ($ millions)	1,480	1,280	420
Net Cost Increase as a Percentage of 2017 PJM Billing	3.4%	3.0%	1.0%

Impacts to Retail Customers

While PJM's proposal will result in an increase in energy and reserve market revenues, it will also result in a decrease in uplift. Based on the simulations, PJM has estimated that its proposal could reduce uplift by up to 42 percent. As stated previously, some of the reduction in uplift can be attributed to the fact that the simulations are run with perfect foresight and no uncertainty. Because of this, the unit commitment and dispatch can be done optimally based on known conditions as opposed to what occurs in real-time operations where there is uncertainty that leads to suboptimal commitments. Regardless, PJM believes that this uplift reduction is beneficial to the market because it results in prices that are more reflective of actual operating conditions and it reduces the unknown level out-of-market charges allocated to retail customers. As a result of this reduction, PJM believes that the portion of retail rates associated with a risk premium to ensure adequate revenues are collected to offset uplift costs will decrease. This decrease in retail rates associated with risk premiums will result in a net savings to retail customers that should be considered.

Despite reaching out to several member companies, PJM was not able to identify the exact portion of the retail rate that applies to an uplift risk premium. However, PJM did calculate a range of estimates based on known information regarding retail rates in its territory.

Figure 13. Assumptions for Retail Rate Reductions due to Uplift Reduction

Average Retail Rate in PJM ($/kWh)	0.124
Percentage of Retail Rate Attributable to Wholesale Costs (%)	43%
Portion of Average Retail Rate Attributable to Wholesale Costs in PJM ($/kWh)	$0.0532
2017 PJM Energy Served (MWh)	773,697,000

Figure 13 shows several components of information important for deriving PJM's estimates. The information regarding the average retail rate in PJM as well as the portion that is attributable to wholesale costs were compiled based on research of publicly available information posted by the Energy Information Administration, the Edison Electric Institute, and also information available in the 2017 State of the Market Report for PJM published by Monitoring Analytics. The net result of this information is that PJM can determine that, on-average, the retail rate charged to PJM consumers is $0.124/kWh and 43 percent of that, or $0.532/kWh, is collected to cover costs associated with the wholesale market.

Figure 14. Cost Savings Due to Reduction in Retail Rates

	Scenario 1	Scenario 2	Scenario 3
Potential Retail Rate Reduction ($/kWh)	0.001	0.00075	0.0005
Percentage of Wholesale Cost Component of Average Retail Rate (%)	1.88%	1.41%	0.94%
Cost Savings to PJM Retail Customers ($ millions/yr)	770	580	390

Figure 14 provides a range of estimates on the reduction in costs to retail loads resulting from a modest reduction in the wholesale portion of the retail rate due to the reduction of uplift. These estimated reductions in the retail rate, while small, can add up very quickly when those reductions are realized across all PJM loads.

Net Impact of PJM's Proposal

The range of net impacts of PJM's proposal can be estimated using the matrix provided in Figure 15. The values in the light blue row across the top represent the expected cost reductions in the capacity market. The values in the light blue column represent the cost savings associated with reductions in the uplift risk premium portion of the retail rate. To determine the net impact, the sum of each row and column combination was subtracted from the $1.92 billion dollar increase that is estimated in the energy and reserve markets.

Figure 15. Net Impact to PJM Consumers

		Capacity Market Cost Reduction ($ millions)		
Cost Savings to PJM Retail Customers ($ millions)		**440**	**640**	**1,500**
	770	710	510	-350
	580	900	700	-160
	390	1,090	890	30

Red: Maximum net additional costs associated with the proposal. **Green**: Least net additional costs associated with the proposal

Based on this analysis, in the most optimistic case for consumers, the net impact could result in a cost savings of $350 million. While this is possible, it is optimistic because it assumes that all capacity resources collect enough additional energy and reserve revenues to reduce their capacity market offers by $30/MW-day and a maximum reduction in the uplift risk premium in retail rates. A potentially more realistic outcome is that these changes will increase costs to loads in the range of $700 million. PJM believes these changes are justified because much of the reserve capability PJM has today is either undercompensated or not compensated at all.

Figure 16. Net Impact Expressed as a Function of 2017 PJM Billing

		Capacity Market Cost Reduction ($ millions)		
Cost Savings to PJM Retail Customers ($ millions)		**440**	**640**	**1,500**
	770	1.7%	1.2%	-0.8%
	580	2.1%	1.6%	-0.4%
	390	2.5%	2.1%	0.1%

Figure 16 expresses the same results as Figure 15 but as a percentage of total PJM billing in 2017). Based on PJM's analysis, an increase in costs in the 1-2 percent range is a likely outcome.

Conclusion

Energy and reserve market reforms are necessary in PJM. PJM continues to believe that accurate reflection of operational needs in Energy and Reserve Market prices is a critical component to the continued success of the competitive electricity markets. The proposed changes will not only more accurately reflect operational needs in Energy and Reserve Market prices, but also reduce the need for operators to take price-skewing, out-of-market actions to maintain reserves by more accurately measuring the reserves on the system and procuring additional reserves, when it is economic to do so, in recognition of the uncertainties that operators must manage. The more the market prices are able to capture the operation of the system and the value of all products, the better the market can function for all stakeholders.

The level of uplift, while small on average, is consistently high during stressed conditions. The failure of the current market rules to produce prices that fully reflect the reliability value of reserves contributes to uplift in both the Energy and Reserve Markets, inappropriately shifts costs, and suppresses price signals that inform resource investment and retention decisions. The proposals described in this paper will enhance the consistency with which prices reflect the value of the resources being counted upon to maintain the energy and reserve requirements on the system. In turn, this will reduce uplift and ensure the market has more reliable price signals upon which to make resource investment decisions.

A further benefit of PJM's proposal to more accurately value reserves is that it puts PJM's market in an advantageous position should there be continued growth of zero-marginal-cost intermittent renewable resources. These resources add to the uncertainty on the system because they are not always directly controllable like a conventional generation resource. More appropriately valuing reserves will send a clear signal for needed flexibility under these conditions.

By moving forward with PJM's proposal, the uncertainty related to increased renewables will be directly accounted for in PJM's reserve requirements and energy and reserve prices, and better reflect the value of a controllable reserve product. Further, while the zero marginal cost nature of these resources would otherwise lead to ever-decreasing energy prices, the incorporation of ORDCs to accurately set reserve prices, which then feed into accurate energy prices, will result in more efficient and transparent energy and reserve prices even in the face of a greater proportion of zero marginal cost resources. The alternative would be to allow the capacity market to pick up a greater and greater proportion of resource revenues, which would not incentivize the flexibility the operators will need to account for in increasing intermittent resources in real-time operations.

PJM recognizes that this package represents a significant evolution to the reserve markets and that some stakeholders may prefer to see a more incremental approach to reserve market reform over time. However, the difficulty in reaching stakeholder consensus on issues that have significant financial impacts makes the passage of successive, significant market reforms extremely challenging. PJM is concerned that attempting to address the proposed reforms through multiple stakeholder efforts would result in a patchwork set of changes that do not holistically address the issues at hand or which create unintended side effects by only partially addressing them. PJM strongly believes that the best course of action is to pursue this comprehensive package of market reforms, which address the full set of reserve market issues. Assuming it is accepted by FERC, this approach will result in the implementation of a complementary set of changes, which will produce efficient market outcomes.