Mitigation and Shortage Pricing in PJM Interconnection

FERC Mitigation and Scarcity Workshop

Docket No. AD14-14-000: Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators

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Purpose of this Report

This report describes technical, operational and market issues related to offer mitigation and market offer caps, and shortage pricing in energy and ancillary services markets. The goal is to provide an educational foundation to understand mitigation and shortage pricing in PJM Interconnection markets.

Appropriate Pricing and Market Transparency

In PJM, Locational Marginal Pricing (LMP) sends appropriate price signals to market participants by accounting for the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM footprint. An integral part of operating an efficient energy market is maintaining consistency between the dispatch instructions sent to supply resources and the LMP at their injection points. This consistency provides the financial incentive for a supply resource to respond in a manner that promotes grid reliability at the lowest cost. The calculation of LMP uses actual operating conditions and energy flows to encourage the efficient use of the electric grid and enhance reliability.

LMP provides transparent price signals that encourage new supply resources to locate to areas where they will benefit the system by reducing transmission congestion. LMP also can identify areas where congestion is common. Additionally, LMP provides price signals that indicate where generation should increase or decrease; where demand, if responsive to price, should increase or decrease; and over time provides longer-term price signals that highlight where new generation or demand should locate or where new transmission would be beneficial. With the information about grid conditions provided by LMP, market participants can observe when and where the system is constrained. Prices also inform market participants of when congestion or supply shortages are taking place and allow them to react efficiently.

Cost-Based and Market-Based Offers in Energy Markets

All generators in PJM energy markets are required to make a cost-based offer. This offer may not exceed the value calculated in accordance with Schedule 2 of the Operating Agreement and Manual 15: Cost Development Guidelines (PJM Manual 15). Generators also may submit a market-based offer, sometimes known as a price-based offer. A market-based offer is a supply offer not constrained by the Cost Development Guidelines and may be greater or less than a generator's cost-based offer. Currently in PJM there is a $1,000/megawatt-hour offer cap that applies to the incremental energy portion of both cost-based and market-based offers.

Generator offers include three components that make up the total cost of operating the resource: 1) the start-up cost, which is a cost incurred each time the generator is brought on-line, 2) the no-load cost, which is the cost of "idling" the generator without injecting megawatts on the system, and 3) the incremental cost, which represents the additional cost of producing electricity at each level of megawatt output.

The Three Pivotal Supplier Test in the Energy Market

In the absence of transmission constraints, the PJM energy market is assumed to be competitive, and no resources are offer capped. PJM screens for potential exercise of market power when resources are determined to be needed to resolve a transmission constraint. In such instances, the "size" of the market is limited to the resources that are located in an area where such resources can relieve the constraint. PJM uses the Three-Pivotal Supplier (TPS) test to determine whether structural market power exists for a given constraint.

A transmission constraint occurs when, because of thermal or reactive limits on the transmission system, energy cannot flow freely to all areas within PJM. Transmission constraints can lead to high energy prices in specific locations because higher-priced, local generation needs to be dispatched to meet demand in areas where lower-priced generation cannot flow freely. The TPS test calculates whether there is an adequate amount of supply available to relieve a constraint while maintaining a competitive market structure.

The TPS test examines the concentration of ownership of supply compared to demand and makes collusion more difficult. PJM and the Independent Market Monitor actively monitor the markets to ensure open, fair, and equitable access to all market participants. To prevent a supplier from exercising market power, defined here as the ability to raise energy prices in a specific area, PJM performs the TPS test. This automatic test determines whether the supply of any single generation owner, when combined with the two largest remaining suppliers, is necessary to meet the megawatt amount needed to relieve a transmission constraint. In other words, if the megawatt amount needed to relieve the constraint cannot be met when removing the supply of the owner being tested and the supply of the other two largest suppliers, then the supplier being tested is determined to be "pivotal." In this context, "pivotal" means that all three suppliers jointly have the potential to exert market power.

After removing the top two largest suppliers and the supplier being tested, if the generation within the constrained area is sufficient, the owner being tested passes the TPS test, and the resource will not be offer-capped. If the remaining generation is not sufficient, the owner being tested and the two largest resource owners fail the TPS test, all three generation suppliers are deemed pivotal, and their resources are offer-capped.

Figure 1: Three Pivotal Supplier Test in the Energy Market Example

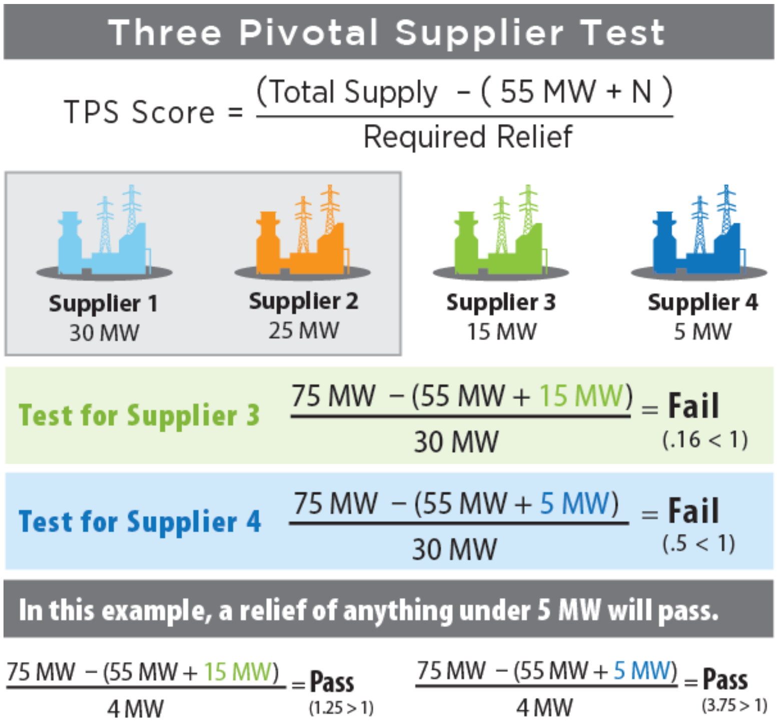

Figure 1 shows a TPS test in the energy market that requires 30 megawatts of relief for a transmission constraint. The total available supply that could help the constraint is 75 megawatts from four different suppliers. The two largest suppliers are Supplier 1, which can supply 30 megawatts, and Supplier 2, which can supply 25 megawatts, for a total of 55 megawatts. Supplier 3 can supply 15 megawatts and Supplier 4 can supply five megawatts. As Figure 1 demonstrates, to provide the 30 megawatts needed to relieve the constraint, Supplier 3 and Supplier 4 will both fail the TPS test. However, if the required relief for a constraint is only four megawatts, all generators will pass as none of the suppliers have potential market power.

A TPS test failure implies that the ownership of the supply[1] needed to meet required relief is concentrated among suppliers that are jointly pivotal with the potential to exercise structural market power. If a generation owner does not pass the TPS test, it triggers mitigation as a preventative step in the event of a concentration of ownership – it does not imply the generation owners are attempting to exercise market power. The pass/fail outcome of the TPS test determines which offer submitted by the generation owner is accepted when that generator is committed to run to relieve the transmission constraint. If the resource owner passes the TPS test, the market-based offer is accepted. When the owner does not pass the TPS test, it is offer capped and the lesser of its cost-based or market-based offer is accepted.

[1] The TPS test analyzes all of an owner's supply available at an effective cost equal to 150 percent of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint. *See* PJM Operating Agreement, 6.4.1.

Three Pivotal Supplier Test in the Regulation Market

The TPS test also is used in the PJM Regulation Market to mitigate market power and is conducted on a supplier basis for each hour. Suppliers which offer into the Regulation Market are ranked from the largest to smallest offered megawatt amount and tested in order, starting with the three largest suppliers.

Regulation TPS test result = (Total Regulation Supply – (Suppliers 1 +2 + N)) / Regulation Requirement

The two largest suppliers are combined with the supplier being tested (N), and their total megawatt supply is subtracted from the total regulation supply offered by all resources. The net amount of supply is divided by the Regulation Requirement for the hour to determine the TPS test result. If the test result is less than or equal to one, then the three suppliers in question are deemed jointly pivotal, fail the TPS test, and their regulation offers are capped at their cost-based offer for the hour in which they failed. If the test result is greater than one, no mitigation is required.

Shortage Pricing

History & Development

Scarcity occurs when there are not enough resources available to balance of generation and load and maintain reserve requirements that are sufficient to respond to short-term system contingencies. In 2006, PJM implemented a scarcity pricing construct designed to allow prices to rise during times of scarcity. The mechanism worked such that when PJM initiated certain emergency operating procedures in a pre-defined market area, offer caps on mitigated resources in the area would be lifted and the LMPs within the region would be set to the highest offer of all resources in the region. While there were a very small number of scarcity events under this construct, PJM had concerns with some design components of the scarcity mechanism as prices did not always react appropriately and consistently to scarcity conditions. For example, the clearing prices of Synchronized Reserve[2] did not accurately reflect scarcity conditions and in some cases remained at zero as energy prices rose. This disconnect between energy and reserve pricing during these events was counter-intuitive, as both should rise during a reserve shortage. There also was a loss of dispatch and pricing granularity within the region which was defined to be scarce because LMPs were set to a uniform value across the region, creating challenges controlling local transmission constraints within the large scarcity region.

As a result of the these issues and in light of FERC Order No. 719[3], which required PJM to revise its rules related to pricing energy and operating reserves[4] during shortage events, PJM and its stakeholders worked to develop

[2] Synchronized Reserve service supplies electricity if the grid has an unexpected need for more power on short notice. The power output of generating units supplying synchronized reserve can be increased quickly to supply the needed energy to balance supply and demand; demand resources also can bid to supply synchronized reserve by reducing their energy use on short notice

[3] *Wholesale Competition in Regions with Organized Electric Markets*, FERC Order No. 719, 125 FERC ¶ 61,071 (2008).

[4] In the current PJM market design, pool-scheduled generation resources that operate as requested by PJM are guaranteed to fully recover their daily day-ahead offer amounts in order to ensure adequate Operating Reserves and to support the PJM Real-Time Energy Market. Day-ahead and real-time operating reserve credits are paid to generation owners; these credits are paid by PJM market participants as operating reserve charges.

new market rules. Despite active and thorough discussion throughout the stakeholder process, PJM stakeholders did not reach a consensus on new market rules. However, because Order No. 719 required PJM to act, PJM filed a shortage pricing mechanism that provides clear and consistent market signals during shortage events and enhances the ability of resources to react to system conditions and meet reliability needs.

Components of Shortage Pricing

Non-Synchronized Reserve Market: Non-Synchronized Reserves are operational reserves that are not currently synchronized to the grid but are able to be started within 10 minutes. With shortage pricing, PJM implemented a Non-Synchronized Reserve Market to be operated along with the current Synchronized Reserve Market. Prior to Shortage Pricing, there was no formal pricing mechanism for Non-Synchronized Reserves. Shortage pricing allows Non-Synchronized Reserves to substitute for Synchronized Reserve when such substitution is cost-effective.

Joint Optimization: Shortage pricing implementation required changes to the real-time dispatch and pricing software. The previous software dispatched energy and reserves in separate applications, and the newly implemented software uses joint optimization to dispatch and price both energy and reserves every five minutes. This ensures consistency between market clearing prices for energy and reserves and reduces out-of-market uplift payments. This optimization between energy and reserves occurs at all times regardless of whether reserves are short or adequate and thus provides market efficiency benefits beyond shortage pricing.

Reserve Demand Curves: Along with the implementation of the joint optimization of energy and reserves, PJM also implemented an Operating Reserve Demand Curve (ORDC), as suggested by FERC Order No. 719. Like the joint optimization, the ORDC is implemented at all times regardless of the reserve level. However, the ORDC is only relevant during shortage conditions when the desired amount of reserves cannot be procured at a price less than that described by the penalty factor. The penalty factor is the dollars/megawatt-hour upper limit set on reserves by the ORDC. During reserve shortages, the clearing price for reserves is set to the penalty factor and provides a clear indicator to market participants that reserves are short.

Mitigation of Market Power: Resources that are offer capped under shortage pricing remain offer capped throughout shortage events, thus ensuring that market power remains mitigated during such events. The continued mitigation of market power throughout shortage events provides confidence to market participants that higher prices are a result of system conditions and reliability needs, not the potential exercise of market power.

Benefits

The implementation of PJM's current shortage pricing mechanism has yielded several notable benefits including:

- More accurate price signals that reflect a higher degree of consistency between ancillary service prices and prevailing energy prices due to joint optimization.
- Resources becoming financially indifferent to whether they provide energy or reserves, thereby enhancing operational reliability.
- The removal of the price suppression effect of emergency actions in which reserve prices did not rise during shortage events even though energy prices rose.

Shortage Pricing Mechanics

Shortage pricing is intended to send a clear signal to market participants that, as the reserve clearing prices approach the penalty factor amount, the system's ability to maintain reserves is becoming increasingly tenuous and a reserve shortage may occur. The mechanics of shortage pricing center on three factors: (1) the existence of a reserve shortage or shortage condition, (2) the implementation of the ORDC and (3) the use of a joint optimization of energy and reserves.

Shortage pricing will be triggered under either of two conditions: (1) the amount of available reserves dips below the reserve requirement for a predetermined amount of time or (2) a Voltage Reduction Action or Manual Load Dump Action is initiated. Conditions that trigger shortage pricing are outlined in the PJM Manual 13 Emergency Operations protocol. Shortage pricing is triggered by reserve zone, regardless of the condition that triggers the reserve shortage. Therefore, if a reserve shortage event occurs in one region of the PJM footprint it may not occur in another if reserves in the other region are adequate. Shortage pricing will remain in effect until the reserve shortage is rectified, and it cannot be terminated if a voltage reduction and/or manual load dump is in effect in the region.

When the reserve requirement cannot be met, the reserve shortage will be priced utilizing the ORDC, which has a two-pronged effect.

1. It sets reserve prices to a clear, pre-defined value (the penalty factor) indicating to market participants that the system no longer has adequate resources to meet the demand and reserve needs of the system.

2. It is incorporated into the LMP calculation to ensure that LMPs during a shortage period do not decline, which could occur as a result of reducing the output of inexpensive generation to provide reserves.

Shortage Pricing Example

Table 1: Generator Energy Offer, Total and Reserve Capacity: Reserve Requirement 200 megawatts

		Energy Offer ($/MWh)	Total Capacity (MW)	Reserve Capability (MW)
Generator	A	$25	300	80
	B	$40	400	100
	C	$60+$1/MW Output	400	120
Reserve Requirement 200 MW		Penalty Factor for Being Short Reserves $400		

In this example, in the region, there are three generators that provide energy and reserves. The regional requirement for reserves is 200 megawatts, and the penalty factor, according to the ORDC curve, is $400 per megawatt- hour.

Table 2: Generator C cost curve example

Output (MW)	Calculation	Offer ($/MW)
10	**$60 + (10 MW * $1/MW)**	**$70/MW**
100	**$60 + (100 MW * $1/MW)**	**$160/MW**
250	**$60 + (250 MW * $1/MW)**	**$310/MW**
300	**$60 + (300 MW * $1/MW)**	**$360/MW**

Generator C has an energy offer of $60 + $1 per megawatt. This is intended to simulate an offer curve rather than a fixed offer like units A and B. (*see* Table 2).

Table 3: Example when Load is 490 megawatts

Generator	Energy Offer ($/MWh)	Total Capacity (MW)	Reserve Capability (MW)	Assigned Energy (MW)	Assigned Reserve (MW)
A	$25	300	80	300	0
B	$40	400	100	190	100
C	$60+$1/MW	400	120	0	100
Reserve Requirement 200 MW			Penalty Factor for Being Short Reserves $400		

Table 3 shows that, when load is 490 megawatts and the reserve requirement is 200 megawatts, the total system requirement is 690 megawatts. In this scenario, the marginal unit for energy is unit B, which sets the LMP to $40/megawatt-hour, and the marginal unit for reserves is unit C, which sets the reserve clearing price at $0.

Table 4: Example when Load is 890 megawatts

Generator	Energy Offer ($/MWh)	Total Capacity (MW)	Reserve Capability (MW)	Assigned Energy (MW)	Assigned Reserve (MW)
A	$25	300	80	300	0
B	$40	400	100	320	80
C	$60+$1/MW	400	120	270	120
Reserve Requirement 200 MW			Penalty Factor for Being Short Reserves $400		

When load increases to 890 megawatt in the region (Table 4), the region is getting close to shortage, as the capacity in the region (1,100 megawatts) is barely able to cover load plus the reserve requirement of 200 megawatts (1,090 megawatts needed in total). Energy prices reflect the LMP for the region at $330 ($60+ $1*270 megawatts= $330/megawatt-hour) which is set by unit C. The reserve price of $290 equals the cost of procuring the next megawatt of reserves. It is the cost of exchanging one megawatt of energy on unit B ($40) for one megawatt of energy on unit C ($330) and is calculated by subtracting the price of unit B from the price of unit C. In other words, the least expensive way to get the next megawatt of reserves is to reduce unit B's output by one megawatt to get another megawatt of reserves and replace that megawatt of energy with one from unit C. The cost of that is the $330 cost of the next megawatt from unit C minus the $40 offer of unit B that is saved by backing it down by one megawatt. It can also be viewed as the lost opportunity cost to generator B for reducing energy output to provide reserve (energy price ($330) minus the offer of generator B ($40)).

Table 5: Example when load is 920 megawatts

Generator	Energy Offer ($/MWh)	Total Capacity (MW)	Reserve Capability (MW)	Assigned Energy (MW)	Assigned Reserve (MW)
A	$25	300	80	300	0
B	$40	400	100	340	60
C	$60+$1/MW	400	120	280	120
Reserve Requirement 200 MW			Penalty Factor for Being Short Reserves $400		

When the load increases to 920 megawatts in the region (Table 5), the region is in a reserve shortage event as the generation capacity (1,100 megawatts) cannot serve load and maintain the region's reserve requirement (1,200 megawatts). In this instance, reserve price is set to the reserve penalty factor of $400. The energy price ($440) reflects the penalty factor of $400 plus the offer of the marginal unit for energy, unit B. It is critical to note that, without the ORDC and the use of a joint optimization, the energy price in the case would be $40. This is because, without jointly recognizing the energy and reserve needs on the system, there is no recognition that dispatching unit B up another megawatt of energy causes a shortage in reserves. By using a joint optimization, the impact of both products on each other is accounted for in the dispatch and price calculation, and, therefore, the reserve shortage is reflected in the LMP.

Impact of Shortage Pricing

PJM's implementation of Shortage Pricing on October 1, 2012, was intended to address the short comings of the original scarcity pricing mechanism. The two graphs below demonstrate the harmony that is produced by the joint optimization of energy and reserves.

Figure 2: Pre-Shortage LMP Implementation and MidAtlantic Dominion Synchronized Reserve Price

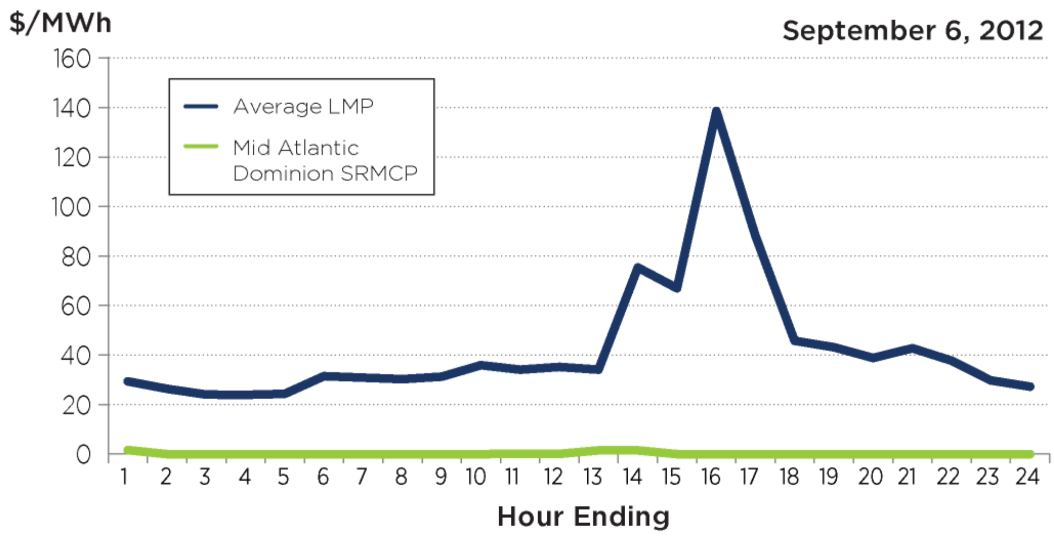

Figure 2 shows the average LMP and Mid Atlantic Synchronized Reserve Market Clearing Price (SRMCP) during pre-shortage implementation in September 2012. The graph depicts high LMPs due to escalating system conditions, but reserve prices are counterintuitively unresponsive.

Figure 3: Post-Shortage Implementation and MidAtlantic Dominion Synchronized Reserve Price

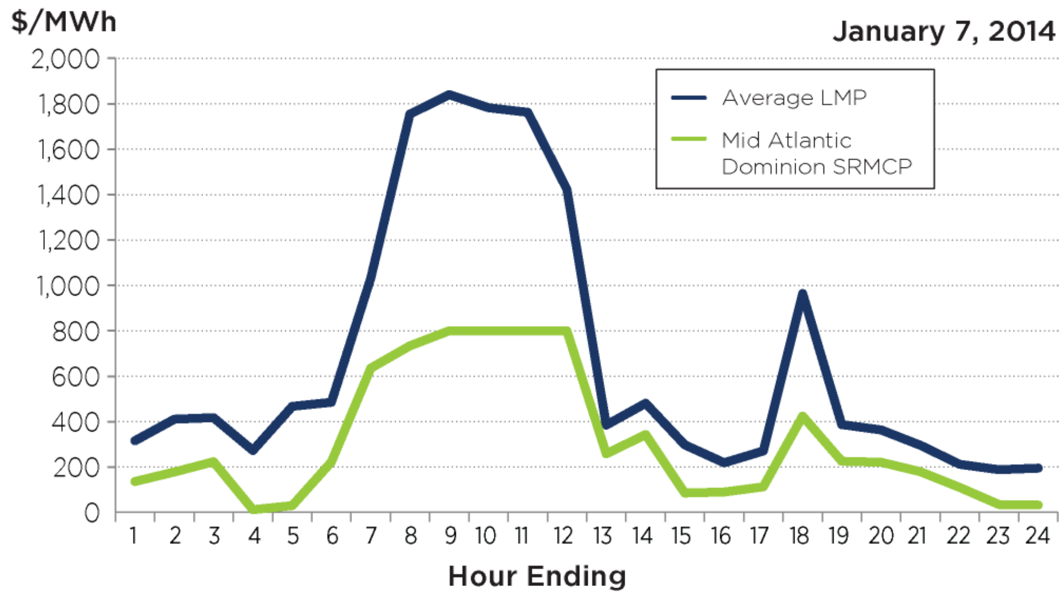

Figure 3 illustrates the value of the joint optimization as the price of energy and reserves are now calculated simultaneously. Both average LMP and the Mid Atlantic Dominion Synchronized Reserve Market Clearing Price, which reflects the price of reserves, move together in a much more correlated manner because they are now co-optimized.