# The 2017/2018 RPM Base Residual Auction:

# Sensitivity Analyses

The Independent Market Monitor for PJM

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# Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), addresses and quantifies the impact on market outcomes in the Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2017/2018 Delivery Year) of the Short-Term Resource Procurement Target and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The IMM will prepare a comprehensive report on the Base Residual Auction for 2017/2018 as the IMM does for each BRA. This report is published in order to provide information to help inform the discussion about the impact of demand side resources on PJM markets based on the recent decision of the United State Court of Appeals for the District of Columbia Circuit.[1]

## *Summary of Results*

Sensitivity analyses of the type reported here show what the market results would have been for identified changes, holding everything else constant. For example, the elimination of all demand side resources from the capacity markets would have increased prices, holding everything else constant. But in the absence of demand side resources, some generating resources that retired in prior years might not have retired, and some new generation resources that did not clear in prior years would have cleared and both would have affected prices in subsequent auctions. In the absence of demand side resources, the market response from generation resources would have been different. In the absence of demand side resources the market response from generation resources would be different in the future. Thus the results of the sensitivity analyses presented here are worst case because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating demand side resources.

Table 1 includes a summary of the results of the sensitivity analyses. The first column includes the total RPM revenues associated with each identified scenario. The second column is the difference in total RPM revenues between each identified scenario and the actual auction results. The third column is the percent change in total RPM revenues between each identified scenario and the actual auction results.

[1] Electric Power Supply Association, et al. v. Federal Energy Regulatory Commission, No. 11-1486 (D.C. Cir. May 23, 2014), *pet. for reh'g en banc pending*.

**Table 1 Summary of sensitivity results: 2017/2018 RPM Base Residual Auction**

| Scenario | Scenario Description | RPM Revenue ($ per Delivery Year) | Difference from Actual Results: RPM Revenue ($ per Delivery Year) | Difference from Actual Results: Percentage |
|---|---|---|---|---|
| 0 | Actual Results | $7,512,229,630 | NA | NA |
| 1 | Annual Resources Only | $9,738,222,922 | $2,225,993,292 | 29.6% |
| 2 | No Offers for DR or EE (Generation Resources Only) | $16,859,658,203 | $9,347,428,573 | 124.4% |
| 3 | No Short-Term Resource Procurement Target Reduction | $9,947,329,539 | $2,435,099,909 | 32.4% |
| 4 | No Short-Term Resource Procurement Target Reduction and Annual Resources Only | $10,932,522,889 | $3,420,293,259 | 45.5% |
| 5 | No Short-Term Resource Procurement Target Reduction and No Offers for DR or EE (Generation Resources Only) | $23,870,404,571 | $16,358,174,941 | 217.8% |

Table 2 includes a summary of the results of the sensitivity analyses associated with the removal of defined demand side products. The first column shows the cleared MW in UCAP. The second column shows the cleared MW in ICAP. The third column shows the level of reserves cleared in excess of the Installed Reserve Margin (IRM), which is PJM's target level of reserves.

**Table 2 Reserves cleared in excess of IRM with peak load forecast reduced by Short-Term Resource Procurement Target: 2017/2018 RPM Base Residual Auction**

| Scenario | Scenario Description | Cleared MW (UCAP) | Cleared MW (ICAP) | Reserves Cleared in Excess of IRM |
|---|---|---|---|---|
| 0 | Actual Results | 167,003.7 | 177,004.5 | 4.4% |
| 1 | Annual Resources Only | 166,237.1 | 176,191.9 | 3.8% |
| 2 | No Offers for DR or EE (Generation Resources Only) | 163,713.2 | 173,516.9 | 2.0% |

Table 3 includes a summary of the results of the sensitivity analyses associated with the removal of demand side resources and the Short-Term Resource Procurement Target and the simultaneous removal of both. The first column shows the cleared MW in UCAP. The second column shows the cleared MW in ICAP. The third column shows the level of reserves cleared in excess of IRM.

The difference between Table 3 and Table 2 is that the third column in Table 3 calculates the excess reserves for the cases with and without the Short-Term Resource Procurement Target in a comparable manner across scenarios.[2] The excess reserves in Table 2 are calculated using a 2.5 percent reduction to the peak load forecast.

[2] In Table 3, the excess reserves calculation includes the 2.5 percent in the numerator and denominator of the calculation for the cases with the Short-Term Resource Procurement Target reduction (scenarios 0-2). The cases without the Short-Term Resource Procurement Target reduction (scenarios 3-5) automatically include the 2.5 percent in the numerator and denominator. In Table 2, the excess reserves calculation excludes the 2.5 percent from the peak load forecast and from cleared MW (scenarios 0-2). This is how PJM calculates excess

**Table 3 Reserves cleared in excess of IRM using alternate calculation method: 2017/2018 RPM Base Residual Auction**

| Scenario | Scenario Description | Cleared MW (UCAP) | Cleared MW (ICAP) | Reserves Cleared in Excess of IRM |
|---|---|---|---|---|
| 0 | Actual Results | 167,003.7 | 177,004.5 | 3.9% |
| 1 | Annual Resources Only | 166,237.1 | 176,191.9 | 3.4% |
| 2 | No Offers for DR or EE (Generation Resources Only) | 163,713.2 | 173,516.9 | 1.6% |
| 3 | No Short-Term Resource Procurement Target Reduction | 170,362.5 | 180,564.4 | 3.8% |
| 4 | No Short-Term Resource Procurement Target Reduction and Annual Resources Only | 170,037.8 | 180,220.2 | 3.5% |
| 5 | No Short-Term Resource Procurement Target Reduction and No Offers for DR or EE (Generation Resources Only) | 164,969.8 | 174,848.8 | (0.0%) |

The analysis shows, for example, that if all Demand Resources (DR) and Energy Efficiency (EE) resources were eliminated from the capacity market (scenario 2), the capacity market would have cleared. The supply curve would have intersected the demand curve on the sloped portion of the Variable Resource Requirement (VRR), or demand curve, at a price of $282.16 per MW-day, which is below the net Cost of New Entry (CONE) and below the maximum RPM price of 1.5 times net CONE. Reliability would have been maintained. Even with the elimination of all DR and EE, the market would have cleared reserves of 2.0 percent in excess of IRM, the target reserve margin.

The analysis also shows, for example, that if all DR and EE and the 2.5 percent demand reduction (Short-Term Resource Procurement Target) were eliminated from the capacity market (scenario 5), the supply curve would have cleared on the sloped portion of the VRR or demand curve at a price of $396.46 per MW-day, which is above net CONE and below the maximum RPM price of 1.5 times net CONE. Reliability would have been maintained. Even with the elimination of all DR and EE and the removal of the 2.5 percent demand reduction, the market would have cleared reserves equal to IRM, the target reserve margin.

# Results

## *Impact of Limited and Extended Summer DR Product Types*

Effective for the 2014/2015 Delivery Year, the RPM market design incorporated Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type. Each DR product type is subject to a defined period of availability, maximum number of interruptions, and maximum duration of interruptions. The Limited DR and the Extended Summer DR product types are both inferior to Generation Capacity Resources, because the obligation to deliver associated

reserves in the BRA. In the PJM calculation, the excess is defined relative to 97.5 percent of the peak load forecast.

with both product types is inferior to the obligation to deliver associated with Generation Capacity Resources. Generation resources are obligated to provide capacity every hour of the year if called.

Effective for the 2017/2018 Delivery Year, the Minimum Annual and Extended Summer Resource Requirements were replaced by Limited and Sub-Annual Resource Constraints. The Limited Resource Constraint limits the quantity of Limited DR that can be procured, and the Sub-Annual Constraint limits the quantity of Limited DR and Extended Summer DR that can be procured. Under the prior rules, the quantity of Limited DR and Extended Summer DR were not capped in this way. Under the prior rules, if the Minimum Annual Resource Requirement were a binding constraint, the Extended Summer and Limited DR products could fill in the balance of capacity needed to meet the VRR curve. These modifications reduced the impact of Limited and Extended Summer DR on market outcomes.

The inclusion of the limited demand side products in the auction had a significant impact on the auction results.

Table 4 shows the results if only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. All offers for Extended Summer and Limited DR products were excluded from supply. All offers for Annual DR were included in supply, including those in non-coupled and coupled DR offers. The RTO clearing price would have increased by 31.5 percent to $157.80 per MW-day, and the clearing quantity would have decreased 0.5 percent to 166,237.1 MW.[3] The PSEG clearing price would have increased by 2.3 percent to $220.00 per MW-day, and the clearing quantity would have decreased 0.1 percent to 6,103.4 MW.

The net CONE for the RTO for the 2017/2018 RPM BRA was $351.39 per MW-day. The price at Point A on the VRR Curve defines the maximum clearing price for a Locational Deliverability Area (LDA) in a BRA. The price at Point A on the VRR Curve for the RTO for the 2017/2018 BRA was 1.5 times net CONE, or $527.09 per MW-day.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $9,738,222,922, an increase of $2,225,993,292, or 29.6 percent, compared to the actual results (Table 1). From another perspective, the inclusion of the Limited and

[3] The MW values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs and external source zones unless otherwise specified.

Extended Summer DR products resulted in a 22.9 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the Limited and Extended Summer DR products.

**Table 4 Scenario 1: Impact of DR product types**

| | | Actual Auction Results | | Annual Resources Only | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $106.02 | 2,322.1 | | |
| | Extended Summer | $120.00 | 7,163.3 | | |
| | Annual | $120.00 | 157,518.3 | $157.80 | 166,237.1 |
| RTO Total | | | 167,003.7 | | 166,237.1 |
| PSEG | Limited | $201.02 | 177.5 | | |
| | Extended Summer | $215.00 | 154.8 | | |
| | Annual | $215.00 | 5,778.4 | $220.00 | 6,103.4 |
| PSEG Total | | | 6,110.7 | | 6,103.4 |
| PPL | Limited | $40.00 | 41.7 | | |
| | Extended Summer | $53.98 | 183.3 | | |
| | Annual | $120.00 | 9,123.5 | $157.80 | 10,543.8 |
| PPL Total | | | 9,348.5 | | 10,543.8 |

## *Impact of All DR and EE*

Table 5 shows the results if there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased 135.1 percent to $282.16 per MW-day, and the clearing quantity would have decreased 2.0 percent to 163,713.2 MW.

The net CONE for the RTO for the 2017/2018 RPM BRA was $351.39 per MW-day. The price at Point A on the VRR Curve defines the maximum clearing price for an LDA in a BRA. The price at Point A on the VRR Curve for the RTO for the 2017/2018 BRA was 1.5 times net CONE, or $527.09 per MW-day.

The inclusion of sell offers for Demand Resources and Energy Efficiency resources had a significant impact on the auction results.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $16,859,658,203, an increase of $9,347,428,573, or 124.4 percent, compared to the actual results (Table 1). From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 55.4 percent reduction in RPM revenues for the

2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

**Table 5 Scenario 2: Impact of DR and EE**

| | | Actual Auction Results | | No Offers for DR or EE | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $106.02 | 2,322.1 | | |
| | Extended Summer | $120.00 | 7,163.3 | | |
| | Annual | $120.00 | 157,518.3 | $282.16 | 163,713.2 |
| RTO Total | | | 167,003.7 | | 163,713.2 |
| PSEG | Limited | $201.02 | 177.5 | | |
| | Extended Summer | $215.00 | 154.8 | | |
| | Annual | $215.00 | 5,778.4 | $282.16 | 6,177.1 |
| PSEG Total | | | 6,110.7 | | 6,177.1 |
| PPL | Limited | $40.00 | 41.7 | | |
| | Extended Summer | $53.98 | 183.3 | | |
| | Annual | $120.00 | 9,123.5 | $282.16 | 9,879.3 |
| PPL Total | | | 9,348.5 | | 9,879.3 |

## *Impact of Short-Term Resource Procurement Target*

Under the current rules, application of the Short-Term Resource Procurement Target means that 2.5 percent of the reliability requirement is removed from the demand curve. The stated rationale is that this provides for short lead time resource procurement in Incremental Auctions for the given Delivery Year. For the 2017/2018 BRA, the 2.5 percent reduction resulted in the removal of 4,125.2 MW from the RTO VRR or demand curve and the Limited Demand Resource and Sub-Annual Resource Reliability Targets.

The Short-Term Resource Procurement Target had a significant impact on the auction results. The removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for all the RPM LDA markets. The clearing quantities of Annual Resources, including generation and DR, were reduced as a result of the 2.5 percent demand reduction.

Table 6 shows the results if the VRR curves and Demand Resource Constraints had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same. For example, the RTO clearing price for Limited would have increased 36.8 percent to $145.02 per MW-day, and the RTO clearing price for Extended Summer and Annual Resources would have increased 31.5 percent to $157.80 per MW-day. The total RTO clearing quantity would have increased 2.0 percent to 170,362.5 MW.

The net CONE for the RTO for the 2017/2018 RPM BRA was $351.39 per MW-day. The price at Point A on the VRR Curve defines the maximum clearing price for an LDA in a

BRA. The price at Point A on the VRR Curve for the RTO for the 2017/2018 BRA was 1.5 times net CONE, or $527.09 per MW-day.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If the VRR curves and Demand Resource Constraints had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $9,947,329,539, an increase of $2,435,099,909, or 32.4 percent, compared to the actual results (Table 1). From another perspective, the use of the Short-Term Resource Procurement Target resulted in a 24.5 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the 2.5 percent reduction of demand.

The 2.5 percent offset was implemented to permit DR to clear in Incremental Auctions as indicated in the name of the adjustment, the Short-Term Resource Procurement Target. The offset was not added to counter persistent forecast errors. Forecast errors should be addressed directly and explicitly for all PJM forecasts. It is essential that PJM use the same forecasts for capacity markets and for transmission planning to ensure the long term consistency of Regional Transmission Expansion Planning Process (RTEPP) and RPM. PJM does use the same forecast for both, but then effectively reduces the forecast in the capacity market by 2.5 percent. To effectively use a lower forecast for capacity requirements in RPM by reducing demand by an arbitrary 2.5 percent results in biasing the overall market results in favor of transmission rather than generation solutions to reliability issues.

**Table 6 Scenario 3: Impact of Short-Term Resource Procurement Target**

| | | Actual Auction Results | | No Short-Term Resource Procurement Target Reduction | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $106.02 | 2,322.1 | $145.02 | 2,322.1 |
| | Extended Summer | $120.00 | 7,163.3 | $157.80 | 7,288.7 |
| | Annual | $120.00 | 157,518.3 | $157.80 | 160,751.7 |
| RTO Total | | | 167,003.7 | | 170,362.5 |
| PSEG | Limited | $201.02 | 177.5 | $207.22 | 175.4 |
| | Extended Summer | $215.00 | 154.8 | $220.00 | 157.0 |
| | Annual | $215.00 | 5,778.4 | $220.00 | 6,056.7 |
| PSEG Total | | | 6,110.7 | | 6,389.1 |
| PPL | Limited | $40.00 | 41.7 | $75.00 | 63.4 |
| | Extended Summer | $53.98 | 183.3 | $87.78 | 161.6 |
| | Annual | $120.00 | 9,123.5 | $157.80 | 10,421.5 |
| PPL Total | | | 9,348.5 | | 10,646.5 |

## Impact of Short-Term Resource Procurement Target and Limited and Extended Summer DR Product Types

Table 7 shows the results if the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased 44.8 percent to $173.76 per MW-day, and the clearing quantity would have increased 1.8 percent to 170,037.8 MW.

The net CONE for the RTO for the 2017/2018 RPM BRA was $351.39 per MW-day. The price at Point A on the VRR Curve defines the maximum clearing price for an LDA in a BRA. The price at Point A on the VRR Curve for the RTO for the 2017/2018 BRA was 1.5 times net CONE, or $527.09 per MW-day.

The combination of the Short-Term Resource Procurement Target and Limited and Extended Summer DR products had a significant impact on the auction results.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $10,932,522,889, an increase of $3,420,293,259, or 45.5 percent, compared to the actual results (Table 1). From another perspective, the use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products resulted in a 31.3 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the Short-Term Resource Procurement Target or the Limited and Extended Summer DR products.

**Table 7 Scenario 4: Impact of Short-Term Resource Procurement Target and DR product types**

| | | Actual Auction Results | | No Short-Term Resource Procurement Target Reduction and Annual Resources Only | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $106.02 | 2,322.1 | | |
| | Extended Summer | $120.00 | 7,163.3 | | |
| | Annual | $120.00 | 157,518.3 | $173.76 | 170,037.8 |
| RTO Total | | | 167,003.7 | | 170,037.8 |
| PSEG | Limited | $201.02 | 177.5 | | |
| | Extended Summer | $215.00 | 154.8 | | |
| | Annual | $215.00 | 5,778.4 | $225.00 | 6,381.6 |
| PSEG Total | | | 6,110.7 | | 6,381.6 |
| PPL | Limited | $40.00 | 41.7 | | |
| | Extended Summer | $53.98 | 183.3 | | |
| | Annual | $120.00 | 9,123.5 | $173.76 | 10,546.7 |
| PPL Total | | | 9,348.5 | | 10,546.7 |

## *Impact of Short-Term Resource Procurement Target and All DR and EE*

Table 8 shows the results if the VRR curves had not been reduced by the Short-Term Resource Procurement Target and no DR or EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased 230.4 percent to $396.46 per MW-day, and the clearing quantity would have decreased 1.2 percent to 164,969.8 MW.

The net CONE for the RTO for the 2017/2018 RPM BRA was $351.39 per MW-day. The price at Point A on the VRR Curve defines the maximum clearing price for an LDA in a BRA. The price at Point A on the VRR Curve for the RTO for the 2017/2018 BRA was 1.5 times net CONE, or $527.09 per MW-day.

The combination of the Short-Term Resource Procurement Target and demand side products had a significant impact on the auction results.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and no DR or EE were offered in the 2017/2018 RPM Base Residual Auction, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $23,870,404,571, an increase of $16,358,174,941, or 217.8 percent, compared to the actual results (Table 1). From another perspective, the use of the Short-Term Resource Procurement Target together with the inclusion of DR and EE offers resulted in a 68.5 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the Short-Term Resource Procurement Target, DR or EE offers.

**Table 8 Scenario 5: Impact of Short-Term Resource Procurement Target, DR and EE**

| | | Actual Auction Results | | No Short-Term Resource Procurement Target Reduction and No Offers for DR or EE | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $106.02 | 2,322.1 | | |
| | Extended Summer | $120.00 | 7,163.3 | | |
| | Annual | $120.00 | 157,518.3 | $396.46 | 164,969.8 |
| RTO Total | | | 167,003.7 | | 164,969.8 |
| PSEG | Limited | $201.02 | 177.5 | | |
| | Extended Summer | $215.00 | 154.8 | | |
| | Annual | $215.00 | 5,778.4 | $396.46 | 6,421.7 |
| PSEG Total | | | 6,110.7 | | 6,421.7 |
| PPL | Limited | $40.00 | 41.7 | | |
| | Extended Summer | $53.98 | 183.3 | | |
| | Annual | $120.00 | 9,123.5 | $396.46 | 9,879.3 |
| PPL Total | | | 9,348.5 | | 9,879.3 |

# Conclusions and Recommendations

Demand Resources have played a significant role in the PJM capacity market. But should a legal or policy decision be made to eliminate Demand Resources from its current participation as supply in the PJM capacity market, PJM markets could adapt. The sensitivity analyses in this report show that holding everything else constant, if all DR and EE had been eliminated from the 2017/2018 BRA (scenario 2), the PJM capacity market would have had clearing prices substantially below the level required for new entry and maintained a reserve margin in excess of PJM's target reserve margin.

The fact that the sensitivity analyses reported here hold everything else constant is important for considering the actual impacts of the elimination of DR. The elimination of all DR from the capacity markets from the inception of the RPM market design would have increased capacity prices, holding everything else constant. Those price increases would likely have meant that some generating resources that retired in prior years would not have retired, and some new generation resources that did not clear in prior years would have cleared and both would have affected prices in subsequent auctions. In the absence of DR, the market response from generation resources would have been different. In the absence of DR, the market response from generation resources would be different in the future. In the absence of DR, PJM would not have reached emergency status as frequently and generating resources would have produced energy rather than DR reducing load.[4] Thus, the results of the sensitivity analyses presented here are worst case, in the sense that the increases in prices and reductions in quantities cleared are at maximum levels, because the sensitivity analyses do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR.

DR has cleared in PJM capacity markets, where 90 percent of all DR revenues are earned in PJM.[5] While there are questions about the details of the measurement and the exact level of response, DR has responded when called. It should not be considered unusual or extraordinary or even noteworthy that a resource being paid the capacity price responds when called consistent with its obligations to respond. Any assertions about the critical role of DR in actual markets ignores the fact that DR displaced generating units that would have provided both capacity and energy more reliably than DR, for many more hours and for much lower energy prices. Limited DR has an obligation to perform for only 60 hours in a year compared to 8,760 hours for a generating unit. The energy strike price of limited DR is generally in the range of $1,000 per MWh to $1,800 per MWh while the average cost of a gas fired combined cycle unit is around $50 per MWh.[6]

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[7] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

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4 DR is only dispatched when PJM calls an emergency. An emergency exists when the supply of available generation is low relative to load. When DR displaces generation it means that emergency conditions exist at lower load levels.

5 See the *2013 State of the Market Report for PJM* (March 13, 2014), Volume II, Section 6, “Demand Response,” p. 199.

6 The actual cost of a combined cycle is a function of the cost of natural gas.

7 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

As a result of the IMM recommendations, this report includes sensitivity analyses of the combined impact of eliminating DR and eliminating the 2.5 percent offset in order to capture the potential maximum impacts of eliminating DR. The results show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained.

The fact that this second set of sensitivity analyses also hold everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are also worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.