Capacity Performance Initiative

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PJM's Capacity Performance proposal will provide benefits by establishing a clear definition for the obligations of capacity resources and establishing clear performance criteria. This proposal will provide enhanced reliability at the lowest feasible cost. Operational events during the winter of 2014 highlighted issues related to generation performance and increasing dependence on gas for power generation during winter peak conditions. Recent operational trends and the changing mix of resources clearing in the forward Reliability Pricing Model capacity auctions have also highlighted the significant impact of the industry transition from coal to gas, driven by the economics of shale gas and the increasing environmental restrictions on coal-fired power plants. Concerns regarding resource diversity and potential nuclear plant retirements have also demonstrated a need to review the resource adequacy and capacity market constructs to ensure that long-term reliability of the power grid will be maintained at the lowest feasible cost. Discussion with gas industry experts has indicated a need to define clear fuel security requirements for gas-fired power plants in order to incent proper investment in gas infrastructure (pipelines and storage) to support the growing needs of the power generation sector.

The Capacity Performance proposal is designed to incent operations-related investments at existing resources for improvements such as weatherization, flexible fuel arrangements and dual fuel capability. The proposal also provides strong incentives for investment in new capacity that is highly reliable and available to meet demand during peak system conditions. The incentive structure will also encourage investment in low-operating-cost, highly flexible resources which will reduce costs in the energy markets. These incentives will result in a generation fleet that is better able to endure weather challenges and perform when needed to meet customer demand in the most economically efficient manner.

The Capacity Performance proposal is expected to increase capacity costs due to increased investments needed to ensure improved resource reliability and availability during various extreme weather events. The investments needed could include gas system infrastructure additions and improvements, dual fuel capability, weatherization and improved maintenance. However, these investments will result in lower energy market costs, will reduce operational limitations on generation resources and will result in improvements to the flexibility and operational diversity of the generation fleet which will reduce out-of-market (uplift) payments. The Capacity Performance proposal will therefore provide enhanced reliability at the lowest feasible cost.

PJM's Capacity Performance proposal represents a significant redefinition of what it means to be a capacity resource in PJM. The proposal is being actively debated within PJM's stakeholder process and it has been and will continue to be modified based on input and comments from stakeholders.

Cost Impact and Offsetting Benefits Estimates

PJM's Capacity Performance initiative will require generators to make significant investments in plant equipment, weatherization measures, better fuel procurement arrangements, expanded fuel supply infrastructure dual fuel capability and other improvements. To encourage this investment, generators must be fairly compensated, resulting in increased capacity costs, which comprised about fifteen percent of consumers' total power bills in 2013 when compared to energy costs which were about 70 percent. The increased capacity costs are expected to be substantially offset by lower energy costs and lower uplift costs, which would result from more efficient use and availability of the generating fleet. In addition, it is important to consider that the overarching purpose of capacity performance—keeping electricity reliable—cannot be considered optional. The Polar Vortex taught us that generators of all types can be vulnerable to arctic temperatures. It is important to balance the value of greater power system reliability against the cost of power interruptions, which can reach tens of billions of dollars and—especially during weather extremes—endanger human life.

Transition Period Estimates

PJM's analysis estimated the annual cost of the increased performance expectations both during the transition years and in future years. The transitional costs for Capacity Performance were based on estimates outlined in PJM's October 7 proposal. The upper bound on capacity costs was estimated by quantifying costs to procure a high estimate of available, incremental capacity at a price equal to Net Cost of New Entry (Net Cone) for the 2015/16 delivery year. The lower bound on cost estimate for 2015/16 was calculated based on a lower estimate of incremental capacity available to be committed. For 2016/17 and 2017/18, the upper bound on costs was estimated by assuming procurement of the target amount of Capacity Performance product (80 percent of capacity cleared) at the proposed price cap levels of 0.5 times Net Cone and 0.6 times Net Cone respectively. The lower bound on the cost estimate for 2016/17 and 2017/18 was calculated based on more realistic estimates of Capacity Performance product commitment in incremental auctions. The range of cost estimates listed below are based on assumptions of the costs of increasing generation performance, securing fuel sources, improving investment in weatherization and risk management costs.

The offsetting energy market cost reductions are based on energy market simulations that quantify the benefit of improving generation outage rates, generation availability and flexibility. PJM executed simulations of actual day-ahead market cases with changes in generator forced outages in order to calculate the benefit to customers of better generator availability. To perform the analysis, PJM re-executed actual day-ahead cases from both the summer and winter periods of 2014, but adjusted generator availability in order to simulate improvements in generation forced outage rates. Cases were executed to simulate improvements of 3 and 6 percentage points in forced outage rates for each of the summer and winter cases in order to ensure that sufficient sensitivities were performed to gauge the reduction in load payments for various scenarios.

The simulations demonstrated that in the winter period, with a 3 percentage point improvement in forced outage rates, load payments were reduced by an average of 5.4 percent. With a 6 percentage point improvement in forced outage rates in the winter simulations, load payments were reduced by 8.7 percent. In the summer period simulations, a 3 percentage point improvement in forced outage rates resulted in an 8.5 percent reduction in load payments, and a 6 percentage point forced outage rate improvement resulted in an 11.6 percent reduction in load payments.

The table below shows actual, monthly average forced outage rates for the 2013/2014 delivery year. From this data, PJM believes that a 6 percentage point improvement in forced outage rates in the winter period and a 3 percentage point reduction in forced outage rates in the summer period are achievable given the incentives and potential penalties outlined in the PJM Capacity Performance proposal.

Month	Year	EFORd (%)	Month	Year	EFORd (%)
June	2013	7.2	December	2013	8.6
July	2013	8.2	January	2014	14.2
August	2013	7.5	February	2014	11.7
September	2013	6.6	March	2014	11.3
October	2013	6.0	April	2014	7.6
November	2013	6.8	May	2014	7.2

Given the average load experienced in winter months and the actual Locational Marginal Prices experienced in January and February of 2014, an 8.7 percent reduction in load payments would be about $975 million. Similarly, given the average load experienced in the summer months and the actual average Locational Marginal Prices observed in June, July and August of 2014, an 8.5 percent reduction in load payments would be about $725 million. Therefore, the total potential reduction in load payments in the five peak winter and summer months combined would be about $1.7 billion. Note that this relatively conservative estimate assumes no benefit in the seven non-peak (shoulder) months of March through May and September through December.

PJM also expects that the limitation on generator dispatch parameters to their physical characteristics during Hot and Cold Weather Alerts would provide a significant reduction in uplift costs during peak periods. Adding a conservative estimate of $500 million in reduced uplift costs (roughly 83 percent of the costs experienced solely in the month of January 2014) would bring the total energy benefit estimate for the Capacity Performance proposal to $2.2 billion.

Delivery Year	Incremental Capacity Cost Range	Energy Market Cost Reduction	Net Incremental Cost
2015/2016	$200 to $600 Million	-	$200 to $600 Million
2016/2017	$2.5 to $3.6 Billion	$2.2 Billion	$0.3 to $1.4 Billion
2017/2018	$3.1 to $4.2 Billion	$2.2 Billion	$0.9 to $2.0 Billion

2018/19 Delivery Year

Based on projections of supply and demand conditions, estimated impacts of the pending market rule changes already filed with FERC and the uncertainty of Demand Response participation, the price of capacity for the 2018/19 delivery year could be between 0.6 and 0.8 times Net Cone absent the proposed Capacity Performance changes. Simulations of the Capacity Performance proposal indicate the price of this product could be between 0.7 and 1.0 times Net Cone in the 2018/19 delivery year. Therefore, based on these simulations, the estimated incremental capacity cost of the Capacity Performance proposal in this year is between $1.9 billion and $ 5.0 billion. The offsetting energy market benefits are conservatively estimated to be approximately $3.0 billion as resource performance, availability and flexibility continue to improve. Therefore the net cost of the Capacity Performance proposal in this year is estimated as between -$1.1 billion and $2.0 billion.

Longer Term Estimates

Both PJM's and the Independent Market Monitor's analysis indicate that over time the price of the Capacity Performance product and the price of the Base Capacity product should trend toward the Net Cost of New Entry. The incremental costs of achieving Capacity Performance requirements for new entry resources are driven by securing reliable fuel sources and by weatherization investment. However, these investments will tend to reduce energy market costs and uplift costs by reducing outage rates and by protecting electricity market customers from increased costs due to gas system limitations. Therefore the long-term net incremental cost of Capacity Performance is estimated in the $300 to $700 million-per-year range, assuming average weather. Preliminary analysis indicates that in extreme weather years, the Capacity Performance proposal could result in net cost savings.