Exelon Corporation (“Exelon”) appreciates the opportunity to submit comments on PJM’s Capacity Performance Proposal (“PJM Proposal”), dated August 20, 2014.

The need for PJM’s proposal is urgent. As detailed below, PJM’s operational challenges during the winter of 2014 confirmed the need to improve our reliability planning construct to ensure safe and reliable electricity for customers at all times throughout the year. On January 7, 2014, nearly one quarter of cleared capacity resources experienced forced outages due to extreme cold and interrupted natural gas supply. PJM narrowly avoided the need to shed load by depleting approximately 500 MW of primary reserves and relying on about 4.2 GW of non-RPM resources that, through good fortune, happened to be available.

PJM’s analysis of historic outage rates demonstrates that 2014 was not an exception. Capacity resources – particularly gas-fired resources – tend to underperform during very cold weather. Just as Hurricane Sandy demonstrated the need to weather-harden our distribution infrastructure against extreme weather events that will inevitably recur, so too we must weather-harden our supply-side resources to maintain system reliability – not only against anomalous weather events but also against the extreme cold that is a regular feature of our winter weather. To date, RPM has performed well in attracting least-cost resources aimed at meeting summer peak demand. However, the capacity mix is rapidly transforming, exposing customers in the PJM region to the frailty of capacity resources that have received insufficient investment to perform reliably during peak summer and winter conditions. Indeed, without immediate action, we face a significant risk that resources will experience performance problems and fail precisely when customers need electricity the most.

While PJM’s Proposal will add some initial costs, the changes recommended below will help to ensure cost-effectiveness for customers over time. First, a supply stack that is “hardened” consistent with PJM’s Proposal will itself produce value by preventing loss of load. Second, in addition to reliability, PJM’s Proposal will reduce energy price volatility by providing fuel oil alternatives when natural gas prices unexpectedly spike. Third, it will also reduce uplift payments made to compensate resources called out of merit.

In May 2014, Exelon retained the NorthBridge Group to conduct an analysis of PJM’s cold weather reliability risks. NorthBridge’s expert analysis (a summary of which is attached to these comments) demonstrates that winter reliability issues will worsen in the coming years. The NorthBridge analysis concludes that the gap between the need for, and existing supply of, winter-reliable RPM generation capacity during extreme winter cold will increase from roughly the 5 GW shortfall experienced in PY 2013/2014 to nearly 16 GW in PY 2017/18. This gap assumes that approximately 10 GW of existing uncleared nuclear and coal capacity that has not already announced retirement remains in the market going forward. The gap would become even larger – growing to nearly 25 GW in PY 2017/18 – if these resources were to retire. Thus, unless changes are made, the probability of a resource adequacy shortfall will increase materially in the coming years. As PJM itself recognizes in its Proposal, a comparable rate of generator

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1 See Wind Chill versus Forced Outages, PJM PowerPoint (September 11, 2014) at 2.
outages in the winter of 2015/2016, combined with expected unit retirements, “would likely prevent PJM from meeting its peak load requirements.” PJM Proposal at 33.

With approximately 80% of residential heating units across PJM dependent on electricity to function (including direct electric resistance heating as well as gas, oil, and propane forced air systems), the loss of electricity in the teeth of cold weather presents an unacceptable danger to customers’ lives and property. Accordingly, Exelon supports PJM’s proposal to define a Capacity Performance (“CP”) product that simultaneously compensates suppliers for enhanced operational reliability and fuel certainty, while penalizing those that do not perform.

Exelon agrees with PJM that penalties for non-performance must be commensurate with the significant harm caused by system reliability failures. As FERC has recognized with regard to the ISO-New England market, “the ability for a market participant’s capacity revenues to become negative is an important aspect of [the ISO’s] proposed market design because it provides an incentive for resource owners to make investments and maintain their resources to help mitigate the risk of non-performance and helps ensure paying consumers receive commensurate reliability benefits.” PJM’s proposed penalty structure is expected to be less stringent than the one recently approved by FERC for New England. Nevertheless, Exelon believes that PJM’s proposed structure is sufficiently stringent to provide generator owners with the economic incentives needed to make investments to weather-harden their facilities, to obtain dual-fuel capability, to store fuel inventories on site, and to otherwise maintain or improve the reliability of their facilities during periods of extreme cold or heat.

To succeed, however, the PJM Proposal needs modification in certain respects to strike a fair balance for customers and suppliers:

- **PJM Should Impose a Must-Offer Requirement:** In order to achieve the fairest price for customers, certain classes of generators should be required to offer their capacity into the CP market. Failure to address the obligation to offer could result in economic withholding to the detriment of customers. Exelon supports requiring resources currently ineligible to provide the CP product to submit linked offers for both the Base Capacity product and the CP product, subject to appropriate market-power mitigation and opportunity to include necessary costs and risk in the linked offer.

- **Generators Must Be Allowed to Make Offers Reflecting the Risk of Low Probability But High Impact Forced Outages:** Generators should be permitted to account for the full risk premium stemming from the penalty structure when submitting their offers. PJM proposes to calculate the allowable “risk premium” based upon the average forced outage rate, the average of penalty window hours, and the average of real-time energy prices during those hours. But PJM’s use of

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“average” figures masks the reality that the expected value of penalties is driven largely by “tail risk” – that is, the risk of a low probability but high impact event, such as a prolonged outage that leaves a unit unable to meet its CP obligation and would result in massive penalties. Generators are very averse to taking on even a low probability of a high impact event, and they should be permitted to make offers reflecting the premium needed to compensate for that risk. Below Exelon suggests concepts to appropriately value such risk.

- **Penalty Structure:** Exelon generally supports PJM’s proposed penalty structure. Exelon strongly supports PJM’s proposal to exempt resources from performance penalties when “PJM did not schedule a unit, or where the unit was on line but dispatched down by PJM.” PJM Proposal at 25. In particular, suppliers should bear the risk of fuel procurement, not customers. PJM’s proposal on penalty structure should be modified in one respect: customers – not suppliers – should be credited for any penalties assessed because customers – not suppliers – are harmed by reliability failures.

- **Officer Certifications Should Be More Precise:** Given that the primary goal of the PJM Proposal is to ensure that electricity is available to customers at the moment when it is most greatly needed, PJM should specify with greater precision the officer certifications that will be required from participating units and the penalties that will be imposed if the certifications misrepresent a unit’s qualification as a CP Resource, regardless of intent. While performance penalties provide after-the-fact relief for customers, certification requirements help to ensure that avoidable misrepresentations are cured.

Finally, Exelon supports PJM’s proposal to hold supplemental CP auctions beginning with the 2015/16 Delivery Year. As described below, the threat to system reliability is urgent, and PJM must act expeditiously to ensure there is an adequate commitment of resources that can provide the CP product.

I. **A Capacity Performance Product Is Urgently Needed To Ensure Reliability.**

A. **PJM’s System Is Highly Vulnerable To Cold Winter Weather.**

The harsh weather of January 2014 spotlighted critical vulnerabilities in PJM’s reliability planning that have been steadily worsening. While RPM has successfully resulted in least-cost capacity procurements sufficient to meet summer peak load, it has also encouraged a concentration of gas-fired generation. However, the increasing reliance on gas-fired generators has had a negative effect on reliability, as gas supply infrastructure and lack of market coordination have provided insufficient gas to meet increasing generator demand.
PJM’s recent analysis of unit performance at low wind chills confirms the hazards of over-relying on gas resources to meet winter peak loads. Specifically, that analysis provides three key insights.

First, gas-fired combustion turbines tend to underperform during cold weather events. There is every reason to believe that performance failures will continue or get worse. Indeed, PJM’s data (spanning the period between 2007 and 2014) demonstrate that megawatts forced out for gas-fired resources in Western PJM are 300-500% greater when the wind chill approaches -10 degrees Fahrenheit than the typical volume of megawatts forced out at higher temperatures. As the wind chill reaches -20 degrees Fahrenheit, the volume of megawatts forced out tends to skyrocket to around 800% of the expected outages when wind chill is over 20 degrees Fahrenheit.

The data further show that natural gas interruptions highly correlate to extreme cold weather events. For example, PJM’s recent analysis demonstrates that, in Western PJM, when the wind chill is between 0 and 5 degrees Fahrenheit, gas curtailments cause megawatts forced out for peakers to approximately double from 3% to 6% of ICAP on average. And, when the wind chill falls below -10 degrees Fahrenheit, gas curtailments increase the volume of megawatts forced out to between 15% and 25% of ICAP. This is not only a problem in PJM. In ISO-New England the operators of natural gas pipelines have reported significant increases in the number of days that pipelines have been constricted – from one day during the 2009-2010 winter to over one hundred days during the 2011-2012.

Second, PJM’s data indicate that, absent dual-fuel capability, all types of gas-fired resources that source gas from local distribution companies (“LDCs”) are particularly unreliable during peak winter conditions, and in zones with a high concentration of gas-fired resources behind LDCs, gas curtailment risk rises markedly at low wind chills. Indeed, PJM’s analysis indicates that about 50% of forced outage volume in such zones is attributable to gas curtailments, despite having a mix of steam, combined cycle and peaking combustion turbines.

Third, PJM’s analysis also indicates that the installation of dual fuel capability can help to reduce forced outages due to gas curtailment. In zones with a significant number of dual-

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4 See Wind Chill versus Forced Outages, PJM PowerPoint (September 11, 2014).
5 See id. at 2, 10 (revealing that gas fired peaking resources are vulnerable to gas curtailment at low winter wind chill).
6 Id.
7 Id. at 10.
8 See Filing of ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes; Docket No. ER14-000 at 95 (Testimony of Peter Brandien, Vice President of System Operations, ISO-NE).
9 See Wind Chill versus Forced Outages, PJM PowerPoint (September 11, 2014) at 11.
10 Id. at 13.
fuel resources, relatively fewer megawatts are forced out due to gas curtailments as compared to zones with many non-dual fuel gas units behind an LDC.\textsuperscript{11}

PJM’s cold-weather vulnerability extends beyond gas plants to coal and oil plants as well, as illustrated by the near load-shed event on the morning of January 7, 2014.\textsuperscript{12} As the PJM analysis below shows, during that time, nearly a quarter of RPM-cleared capacity resources was unavailable for dispatch – including close to half of all gas resources, over 20% of all coal resources, and over 25% of all oil resources.\textsuperscript{13} As a result, real-time energy prices soared, rising to a peak of $1,841 per MWh.\textsuperscript{14}

\textsuperscript{11} Cf., id. at 11 and 13. In presenting the cited material to PJM Members, PJM Staff describe Zone “Z”, depicted in slide 13 as a PJM zone with significant gas generation resources of all types, many of which are equipped with dual-fuel sources and located behind and LDC. In comparison, PJM highlighted that slide 11 depicts Zone “X” which features a mix of combustion turbine, combined cycle and steam resources – with many of the gas resources residing behind an LDC. Both zones feature many gas units behind an LDC, but the zone with units equipped with dual fuel a starkly lower volume of megawatts out at lower temperatures, even when controlling for gas curtailments.

\textsuperscript{12} The peak winter load occurred at 7 pm on January 7, 2014, but the hour of peak system stress, as measured by real-time energy prices and operating reserve shortfalls, actually occurred at around 8:30 am that morning. The morning hour was a time of higher system stress despite somewhat lower load because generator forced outages were higher at that hour and imports fell to nearly zero due to conditions on neighboring systems. PJM Interconnection, “Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events,”, May 9, 2014, at Figures 9 and 13 (hereinafter, “PJM Analysis”).

\textsuperscript{13} PJM Interconnection, Response to Committee Questions of U.S. House of Representatives Committee on Energy and Commerce, April 18, 2014, at Figure 4.

\textsuperscript{14} PJM Analysis at Figure 18.
Faced with the absence of a large percentage of its RPM-committed resources, PJM was forced to deplete primary operating reserves and rely upon surplus wind and voluntary resources (demand response and imports) to avoid load shed. PJM was fortunate that wind over-performed relative to its RPM capacity rating during the hour of peak system stress – generating more than 1 GW in excess of its capacity rating.\(^{15}\) PJM has no control over whether the wind is blowing, and cannot plan system reliability around the vagaries of whether intermittent resources will be able to perform. In fact, later during the January 7, 2014, wind underperformed relative to its capacity rating.\(^{16}\)

PJM also was ultimately able to deploy about 3.2 GW of voluntary resources that had no particular obligation to supply energy. PJM issued a voluntary emergency demand response deployment request, to which about 2.1 GW of demand response voluntarily responded and successfully deployed.\(^{17}\) Going forward, PJM continues to lack mandatory winter interruption

\(^{15}\) PJM Analysis at slide 11.

\(^{16}\) Id.

\(^{17}\) PJM Interconnection, “PJM Demand Response Activity January 7-8, 2014,” March 26, 2014, slide 3. To the extent that these demand response providers were responding to economic incentives caused by high energy prices provided by PJM, the D.C. Circuit’s recent decision overruling Order No. 745, and today’s order denying rehearing in that case, calls into question whether those demand response providers will respond to future calls for voluntary emergency demand response. See Elec. Power Supply Ass’n v. FERC, No. 11-1486 (D.C. Cir. May 23, 2014), reh’g denied (Sept. 17, 2014).
rights for more than 95% of demand response that cleared in RPM for 2014/15 through 2016/17. PJM also relied upon approximately 1.1 GW of voluntary emergency energy imports. Finally, PJM operated with about 0.5 GW less than its primary reserves target.

As depicted below, the total of 3.2 GW of non-firm resources, 1 GW of excess wind, and 0.5 GW of primary reserve shortfall adds up to 4.7 GW of non-RPM resources necessary to operate the system during the hour of peak stress. These resources were not winter-firm capacity resources procured through RPM, and reliance on non-firm resources to meet peak demand is not a good planning practice.

![PJM Reliance on Non-Firm Resources to Maintain Reliability During the Polar Vortex (Jan 7th, 8-9 am)](image)

Source: NorthBridge analysis based on PJM data, as described in text above.

**B. Expected Changes in the PJM Supply Stack Over the Next Several Years Will Exacerbate Cold Weather Reliability Risks.**

PJM has been fortunate so far to avoid an involuntary load-shed event due to extreme cold, but its vulnerability to such an event will grow over the next several years as more coal resources retire and are replaced by natural gas resources. Indeed, 13 GW of capacity with on-site fuel is projected to retire by the end of the 2016/17 Delivery Year. Exelon estimates that an additional 10 GW of capacity with on-site fuel did not clear in RPM for the 2017/18 Delivery Year, and thus may retire. Furthermore, PJM projects that load will continue to grow in the coming years. Between the Winter of 2013/2014 and the Winter of 2017/18, PJM projects that winter peak load will grow by approximately 7 GW, meaning that PJM’s overall winter shortfall will increase by up to 20 GW if no winter-firm resources are added.

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18 PJM Analysis at 19.
19 PJM Winter Operations at slide 13.
These resources are likely to be replaced largely by new or repowered natural gas plants. Through the 2017/18 Delivery Year, about 16 GW of new or repowered gas plants are expected to come online.\textsuperscript{21} Yet many of these facilities will lack dual fuel capability and may be vulnerable to interruptions in gas supply during extremely cold weather. During January 7, 2014, approximately 20\% of existing gas plants experienced a forced outage due to fuel availability problems.\textsuperscript{22} The replacement of retiring coal plants with new natural gas plants will increase the vulnerability of PJM’s fleet to fuel interruptions by placing additional strain on the gas infrastructure.

By 2017, the replacement of coal with gas will increase PJM gas demand by almost 2 BCF/day during cold days. Based on this increased demand, the 2014 level of overall gas demand will be reached when temperatures are 5 to 6 degrees warmer than they were on January 7, 2014. Thus, gas interruptions will occur much more frequently in the future. Moreover, these estimated impacts are based only on announced retirements, and do not account for the potential retirement of the roughly 10 GW of nuclear and coal plants that did not clear RPM in 2017/18 but have not announced retirement. If these plants retire, then the increase in PJM gas demand will exceed 3 BCF/day, and fuel interruptions will occur at even higher temperatures, and thus even more frequently.\textsuperscript{23}

As a result of this change in resource mix together with increased winter peak load projections, PJM’s ability to avoid significant load shed will deteriorate significantly over the next few years, even assuming that PJM can preserve all RPM-cleared nuclear, coal, oil, and dual-fuel resources that have not already announced their retirement. While PJM was able to lean on 4.7 GW of uncommitted capacity resources and reserves depletion to avoid load shed in the past winter, if similar winter conditions were to reoccur in the coming years, PJM would need to rely on several times as much uncommitted, voluntary supply to avoid load shed, making a significant loss of load event a virtual certainty. As indicated in the chart below, under extreme winter conditions PJM would need to rely on 7 GW of uncommitted resources in 2014/15, 17.5 GW in 2015/16, nearly 20 GW in 2016/17, and almost 16 GW in 2017/18. These figures assume that 10 GW of uncleared nuclear and coal capacity does not retire. If those resources do retire, PJM would need to rely on nearly 25 GW of uncommitted resources to avoid load shed in 2017/18. These looming gaps in PJM’s supply portfolio are far too large to be patched over with voluntary resources and luck, as was the case last winter.

\textsuperscript{21} Id.; PJM Interconnection, “2017/18 Base Residual Auction Results,” Table 8.

\textsuperscript{22} PJM Analysis at Figure 16. PJM indicates that roughly 24\% of outages last January, or about 10 GW, was due to gas supply interruptions. Given roughly 50 GW of gas capacity in PJM at the time, this translates to a 20\% forced outage for gas capacity due to fuel supply interruptions alone.

\textsuperscript{23} This does not consider the growing demand for gas for industrial, heating, and other purposes, all of which will further strain gas infrastructure on peak days.
C. PJM’s Proposal Will Have Significant Customer Benefits.

PJM’s proposal to introduce a Capacity Performance product will bring significant benefits to customers. Most fundamentally, of course, PJM’s proposal will result in improved reliability by giving suppliers the market-based incentives needed to invest in winter-hardening of critical equipment, fuel inventories, and dual-fuel capabilities. This is consistent with the storm-hardening benefits that resulted from transmission and distribution system upgrades in the wake of Hurricane Sandy. As the events of January 7, 2014, demonstrated, the current RPM procurement process is not designed to ensure sufficient capacity to meet peak loads during extreme winter weather, with the result that the risk of load shed is in fact higher than the once-in-ten-years planning parameter that RPM is intended to satisfy. Large quantities of RPM-cleared resources on which PJM had relied to ensure peak load plus adequate reserves turned out to be unavailable. Load shedding imposes enormous costs on customers – economic costs for factories and businesses that must shut down, but also public health and safety impacts, particularly in dangerously cold weather. While estimates of the economic cost to customers of loss of load (known as the “Value of Lost Load” or “VOLL”) vary considerably, they are uniformly very high, typically ranging from $9,000 per MWh to as much as $45,000 per MWh. If PJM were forced to shed 20 GW of load, as the foregoing analysis suggests it might, this range of VOLL implies an economic cost to customers of between $180 and $900 million for a single hour. When expanded across a multi-hour or even multi-day cold weather event, consumer costs could amount to many billions of dollars.

PJM’s proposal will also bring other important benefits to customers. First, PJM’s proposal will mandate more secure fuel supply arrangements and create incentives for generators to make investments and adopt operating practices that increase generator availability. By doing so, thereby helping to ensure the continued viability of such generators that already exist, PJM’s proposal will effectively add low-cost baseload and intermediate capacity to the energy market by making it more likely that increased aggregate low-cost capacity will be available for dispatch at any particular point in time. This additional low-cost generation will reduce energy production costs by displacing higher-cost resources that would have been dispatched if the lower-cost resources were unavailable. For example, if efforts to comply with PJM’s capacity performance program result in increasing the year-round average availability of coal generation by 2%, the program will effectively add about 1 GW of baseload capacity to the market – the equivalent of adding a large new supercritical coal unit. The value of this effect is most pronounced during winter conditions, when gas prices are typically high and the production cost savings from replacing gas with coal or nuclear generation are very large.

Second, PJM’s proposal will reduce the volatility of energy prices during the winter and summer peaks by ensuring that sufficient generating capacity can be called upon to minimize the occurrence of scarcity pricing.

Third, and relatedly, by ensuring that winter peak load can be met largely with non-gas or dual-fuel resources or gas resources with a firm gas supply, PJM’s proposal will greatly reduce the amount of out-of-market payments that PJM must make to gas facilities (and ultimately charge to customers) to induce the gas facilities to operate when gas supply conditions are tight. Indeed, PJM customers were forced to pay nearly $600 million in out-of-market uplift to compensate gas facilities that lacked robust transportation arrangements for the cost of entering expensive and inflexible short-term gas supply contracts during the extreme weather in January 2014.

Fourth, the PJM proposal will benefit consumers by requiring resources to offer operating parameters consistent with their actual underlying physical capabilities. Currently, PJM allows offers that deviate from physical capabilities due to financial reasons – for example, a unit may offer on a block load basis because it does not want to incur the additional operational and maintenance costs that result from ramping up and down. PJM’s proposal, however, will require CP Resources to offer based on the technical capabilities of the unit. By doing so, PJM’s

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25 Transcript of FERC September 8, 2014 Technical Conference, “In the Matter of: Price Formation in Energy and Ancillary Services Markets,” Docket No. AD14-14-000, at pp. 86-87 (statement of Stu Bresler) (“I think as ISO-New England has done, as PJM had now proposed to do, changing some of our capacity market rules in order to make sure that we adequately compensate resources for the flexibility that we need in order to operate the system not only reliably and making sure we have the resources we need to maintain reliability, but also efficiently, will also be an extremely important step forward to keeping as much of the system operation in the transparent prices ... to ensure that going forward we incentivize the necessary investment and minimizing that which comes in through uplift does not have the transparency and the stimulus for investment that we really need.”).

26 PJM Analysis at 44.
proposal will ensure a more flexible aggregate dispatch curve of energy resources, which will enhance PJM’s ability to reliably operate the system under volatile weather or outage conditions and generally produce a more efficient economic dispatch. This will reduce energy production costs.

Finally, PJM’s proposal creates improved long-term price signals with respect to gas infrastructure and should lead to more investment in firm gas delivery capacity (if generators enter into firm gas delivery contracts) or reduced gas usage during winter peak conditions (if generators add dual-fuel backup capability). Either way, PJM’s proposal will reduce the likelihood of extreme winter price stress on gas delivery systems and related spikes in the natural gas market within its footprint, which will reduce energy production costs while also benefiting heating and industrial consumers of natural gas.

II. The Must Offer Rules In The Proposal Should Be Clarified.

The PJM Proposal suggests that at least some form of must-offer requirement will exist as part of the Capacity Performance program, but it does not provide any specifics on what form the must-offer requirement would take, or to what types of generators it would apply. See PJM Proposal at 30.

Exelon believes that a must-offer requirement is critical to ensure that customers benefit from PJM’s Proposal and that PJM is able to satisfy its reliability planning parameters. The following factors should be taken into account when the must-offer rule is designed.

First, while a must-offer requirement ensures that customers will be able to depend upon the CP product to deliver reliability, a must-offer requirement also imposes a burden on generators, who have no choice but to participate. Accordingly, a must-offer requirement must be paired with an adjustment to the risk premium as discussed below in section III(B) to account for the substantial penalties a generator could face as a result of a low-probability but extended forced outage. Unless the formula for calculating permissible offers is modified to reflect generators’ true risk premium, generators could be forced to make offers at prices below their actual costs. This would be neither just nor reasonable.

Second, a must-offer obligation should only apply to nuclear, coal, oil, and dual-fuel units. Those units typically will not need to make any major capital expenditures to meet the criteria necessary to qualify as a CP Resource under PJM’s current proposal. Imposing a must-offer requirement for these types of resources would be consistent with PJM rules that impose such a requirement on existing units in the base capacity market. If a unit suddenly became ineligible to provide a CP product, it could petition for the must-offer requirement to be waived, and the unit would then have “Base Capacity” status.

Other resources that must make significant capital expenditures to qualify as CP Resources – for example, gas units that must invest in new dual-fuel capability or gas inventory – should not have any must-offer obligation. Such a unit would be, with respect to the CP product, akin to “new build,” to which must-offer requirements do not apply. Such units would,
however, continue to have a must-offer obligation with respect to base capacity, and should also provide a linked offer to upgrade the unit to CP if the clearing price warrants.

III. The Risk And Reward For Committing Capacity Performance Resources Must Be Balanced To Assure The Desired Market Response.

A. Proposed Penalty Structure.

Under PJM’s proposal, committed CP Resources that clear in the new supplemental auction, but then fail to perform when called upon during hot and cold weather alerts and maximum generation emergency alerts, will face significant performance penalties. PJM has proposed that those penalties be calculated by multiplying the amount of megawatts not delivered by the locational marginal price (LMP) at the generator bus at the moment the generator is called upon. See PJM Proposal at 26. Exelon largely supports this method of calculating performance penalties. Moreover, Exelon strongly agrees with PJM that performance penalties must be substantial enough to prevent market participants from gaming the system by clearing offers but not taking the necessary steps to firm up their fuel supply in the hopes that they will not actually be called upon. Without an adequate penalty structure, PJM cannot achieve its goal of ensuring a firm fuel supply during times of maximum system stress.

Significantly, the penalty structure proposed by PJM is not expected to be as stringent as the one recently approved by FERC for the New England market. Performance penalties in New England are assessed at a very high rate ($2000/MWh initially) compared to the proposed rate in PJM (real-time LMP). The annual expected cost of penalties under PJM’s proposal would be reached in New England after only 2 to 3 hours of forced outages based on New England’s high penalty rate.

Nevertheless, Exelon believes that the penalty structure proposed by PJM is sufficiently stringent to provide the needed economic incentives for generator performance. Moreover, Exelon strongly agrees with PJM that, when a unit fails to perform during a period in which the CP product is subject to performance penalties, an exception to performance penalties should be made in “those instances where PJM did not schedule a unit, or where the unit was on line but dispatched down by PJM.” PJM Proposal at 25. Suppliers, not customers, should bear the risk of fuel availability. There is no unfairness in placing this risk on the supplier, provided that the supplier has the opportunity to include the appropriate risk premium in its offer.

While Exelon generally supports PJM’s proposed penalty structure, it does suggest that the revenues derived from penalties should be distributed to load serving entities, as they will incur the costs of the CP program.

B. The Risk Premium Allowed to be Included in CP Resource Bids Should Take Into Account Low-Probability but High-Cost Outages.

The current PJM proposal provides that resource owners “should have the ability to reflect performance risk, up to some threshold level, during peak periods in their offers so that there is some symmetry between risk and reward of being committed as a Capacity Performance
product.” PJM Proposal at 30. Exelon agrees with the principle that generators should be able to reflect both the incremental cost and risk associated with performance penalties in their supply offers. Generators should be able to rely on their own risk management processes and should have wide discretion in determining how to reflect risk in their offers. Indeed, FERC has recognized as much in approving the ISO-NE tariff, which allows a resource owner to impute its own risk into its offer, above the risk premium established by the Market Monitor, when accompanied by an officer certification.27 Allowing generators to incorporate their true risk premium into their offer price provides economic incentives for units to reduce their exposure to risk in order to make competitive offers, and will result in the most cost-efficient mix of CP resources.

Allowing resource owners to reflect risk in their offers is particularly important to the extent that the CP program includes a must-offer requirement, which forces resources to assume a performance penalty risk. Indeed, many valuable resources might opt for early retirement rather than face the economic risk associated with the performance penalties unless they are able to account for this increased risk through their capacity market offers.

Although Exelon agrees with the basic principle of permitting generators to include their performance risk in their offers, Exelon disagrees with the formula PJM has proposed for determining the maximum allowable performance penalty risk premium. The current proposal seeks to estimate the long-term expected cost of performance penalties by multiplying an expected outage rate for a benchmark “average” generator (7%) by a historical average of penalty window hours (roughly 350 to 500, depending on region) and a historical average of real-time energy prices during those penalty hours ($70 to $100, depending on region and

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27 See ISO New England, 147 FERC 61,172 at P 64, 75 (“While the risk premiums reflected in ISO-NE’s two-settlement capacity market design may increase costs to consumers, we find that, given the nature of the fleet-wide resources performance problems facing the New England region, the market design appropriately balances the increased costs to consumers against the added reliability benefits consumers will receive from a resource fleet with more appropriate incentives and capability to reliably perform when needed.”); see also ISO-New England Tariff, § III.13.1.2.3.2.1.4, “Risk Premium” (“The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource’s risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource’s participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.”).
lookback period). Depending on the inputs, PJM’s formula produces a result of about $5 to $10/MW-day for the risk premium.

The problem with this formula, however, is that it ignores “tail risk” – the fact that the “average” penalty amount is primarily driven by low probability, but very large penalty, events. Even if these events only happen in less than 5% of years, the potential penalties are so significant that they are of preeminent concern to generators. In this regard, generators are not “risk neutral” – tying their estimate of the appropriate performance penalty premium to the “average” penalty they could face spread over a 30-year period – but rather are “risk averse” – primarily concerned with crippling penalties they could face in the worst years.

Thus, the risk calculation fails to account for critical differences in fuel-type performance. Nuclear units, for example, are far more reliable than their fossil counterparts in that they experience many fewer forced outages, but the duration of a nuclear outage when a plant does shut down is typically much longer. Moreover, given the sheer size of nuclear units, an outage can by itself trigger PJM emergency conditions and the attendant penalties for non-performance. The risk premium calculation must be adjusted to recognize the possibility that certain penalty risks, while unlikely to materialize, could be financially ruinous. Indeed, as shown by market evidence discussed below, PJM’s calculation underestimates by about a factor of ten the true risk premium that is needed to compensate generators for assuming that tail risk. It would not be just or reasonable to impose a must-offer obligation on generators unless PJM modifies its calculation of the risk premium to be consistent with market evidence.

For example, consider a nuclear unit that experienced a one-month outage during January 2014. This unit would have accumulated annualized performance penalties equal to $175/MW-day for that one month alone – penalties that are orders of magnitude greater than the $5 to $10/MW-day risk premium PJM has estimated under its proposed formula. In most years a nuclear unit will perform as required and penalties will be minimal. In the worst 5% of years, however, a lengthy outage combined with adverse weather conditions could lead to penalties ballooning to between $50/MW-day and over $100/MW-day. Calculating the risk premium based solely on the average expected penalty ignores the magnitude of these penalties, which are of the greatest concern to generators.

Thus, PJM’s risk premium formula should be modified to allow CP Resources to include the risk they will face from low probability but high cost outages – including outages that are unrelated to fuel availability. Exelon believes the best way for PJM to recognize the real cost to generators associated with this additional risk would be for PJM to use market-based evidence on the appropriate pricing of such risk.

There are at least two potential sources of such market-based evidence that should be considered in revising PJM’s risk premium formula. First, the spread between liquidated damages (“LD”) contracts and unit contingent (“UC”) contracts provide one useful benchmark. LD contracts obligate a seller to deliver power to a buyer at a fixed price regardless of the outage status of a given generating unit. That is in contrast to UC contracts, which only obligate the seller to deliver power if the unit to which the sale is linked is available. A seller supplying energy through a contract with LD provisions will thus need to source power out of the spot
market (and sell that power at a fixed price) if its unit is unable to generate electricity. By contrast, a UC seller will not need to take on this additional cost and risk. There is almost no expected cost related to selling LD power versus UC power because spot prices at the time of an outage could be lower or higher than the fixed sales price. But selling LD power is significantly riskier than selling UC power because of the possibility of an extended outage when spot prices are very high. Because an LD seller accepts the risk of an outage occurring at the same time that spot prices are high, the risk profile that exists in an LD contract is very similar to the risk profile a CP Resource would accept under the CP program.

The graph below shows the cumulative distribution of performance penalty costs for an Eastern PJM nuclear unit, as well as the cumulative distribution of annual losses incurred for an LD seller versus an all-else-equal sale of UC power for a typical nuclear unit in Eastern PJM. As the graph demonstrates, the tail outcomes (90th, 95th, and 99th percentile) for performance penalties are very similar to the tail outcomes for the realized losses of an LD seller as compared to a UC seller. Therefore, the market-based spread between UC and LD forward power sales is an excellent proxy for the appropriate market-based risk premium for performance penalties.

![Graph showing cumulative distribution of performance penalty costs](image)

Source: Exelon Internal Simulation Modeling

Exelon has extensive real-world transaction experience with both UC and LD power sales and purchases. In Exelon’s experience, UC all-hours energy sales linked to nuclear units typically trade at a $1.5 to $4.0 per MWh discount to LD products with otherwise identical terms, depending on the reliability of the unit in question. Translated into dollar-per MW-day terms, LD contracts thus receive a market-based risk premium of roughly $35 to $90 per MW-day.
Second, insurance contracts provide a useful market-based benchmark for the appropriate risk premium. Generators such as Exelon can purchase insurance to offset the risk that their units will have a forced outage during a hot or cold weather alert. This insurance would be structured to pay the generator the real-time LMP in the event that it is forced out or derated during a hot or cold weather alert and thus completely offsets all costs and risks associated with performance penalties. Thus, the price of this insurance product is a direct market-based estimate of the appropriate risk-adjusted cost of performance penalties.

PJM could develop a fixed risk premium value — or “safe harbor” — based on currently available market data or a PJM-run solicitation of insurance products that mitigate the performance penalty risk for a typical generator. This safe harbor would provide all generators the ability to bid up to a default risk premium level without additional justification. However, the actual cost of such an insurance policy and related premium could be higher for certain units, depending on their location and particular characteristics. For example, proximity to a liquid trading point (for purchasing replacement energy) and other factors could play into the premium calculation.

In line with this proposal, Exelon has obtained indicative quotes for a limited liability insurance product linked to its Limerick 1 unit. This insurance is structured to pay Exelon the real-time LMP at PJM West when Limerick 1 is on a forced outage and PJM is under either a hot or cold weather alert. These quotes represent a low-end estimate of the market-based risk premium of performance penalties faced by market participants at large because (1) they are linked to a highly reliable nuclear unit, rather than a less reliable gas or coal unit, (2) the quotes are tied to real-time prices at the PJM West Hub rather than the generator bus, which creates less price risk during a generator outage, and (3) they contain a fixed loss-limitation of $225/MW-day, rather than the 2.5 multiple of the RPM clearing price that PJM has proposed. Even though this product would only cover a portion of a generator’s penalty risk, the indicative quotes result in a value that is a multiple of PJM’s proposed formula.

Using market-based evidence, PJM should be able to establish a safe harbor price as a default risk premium. If PJM chooses this option, however, it should also develop tariff provisions that would allow generators to confidentially submit market-based evidence, such as a unit-specific insurance quote, in support of a risk premium in excess of the default amount determined by PJM.

IV. Certification and Monitoring Must Be Strengthened.

Exelon supports PJM’s proposed resource qualification criteria. However, the proposed officer certification and enforcement provisions must be strengthened in several respects, in order to ensure that participating resources are truly able to meet the qualification criteria.

For example, PJM has proposed that, in order to qualify as a CP Resource, a resource must be able to operate at its Capacity Performance Installed Capacity value for at least 16 hours.

28 To the extent that an insurance policy contains a fixed loss limitation, an additional risk premium would need to be added to cover the uninsured portion of the potential loss.
per day for three consecutive days throughout the delivery year. PJM has indicated that, to satisfy this criterion, “it is expected” that a coal-fired resource will have on-site fuel and that a gas-fired resource will have oil backup. See PJM Proposal at 8 (emphasis added). Further, PJM has indicated that “it is assumed” that a gas-fired resource has “appropriate transportation arrangements to ensure delivery of fuel when it is needed…”. Id. (emphasis added).

Yet PJM stops short of requiring an officer to certify that, in fact, PJM’s expectations and assumptions are borne out in reality. That aspect of PJM’s proposal should be modified. PJM should require an officer to certify not only that a resource is able to operate for at least 16 hours per day for three consecutive days, but also that the conditions exist that would enable such operation – fuel on site in the case of a coal-fired facility, and dual-fuel capacity or firm gas delivery arrangements in the case of gas-fired facility.

Further, Exelon is concerned that the lack of oversight regarding officer certification could lead to gaming. While the concern could be assuaged by PJM or third-party review, Exelon recognizes that such review may be impractical. However, the lack of oversight regarding certification underscores the need to maintain a materially high penalty structure in order to encourage proper market behavior.

PJM should also strengthen its enforcement provisions to verify the truthfulness of the officer certification in the event that a unit is called upon but unable to perform. For example, PJM should require that any CP Resource that experiences a forced outage during times in which performance penalties are in effect must submit a post-outage report. That report should affirmatively demonstrate that the outage was not caused by a failure to implement measures necessary for the resource to meet the criteria for the CP product. If the report fails to make such a demonstration, or if the officer certification is determined to be false, the unit should be subject to enhanced penalties, including:

- Disgorgement of all capacity revenues for the unit in question.
- Disgorgement of any fuel-scarcity-related uplift payments received by the unit.
- Referral to FERC for enforcement action.

These enhanced penalties should be imposed in addition to the usual penalties for non-performance.

V. Procurement Quantities.

Exelon supports PJM’s approach to establishing the CP procurement target.

VI. Supplemental Auctions.

As discussed above in Part I, there is an urgent need to enhance winter reliability. Indeed, PJM’s own analysis confirms that, if there were a comparable rate of generator outages in the winter of 2015/2016, those outages, combined with expected coal retirements, “would
likely prevent PJM from meeting its peak load requirements.” PJM Proposal at 33. Plainly, PJM cannot continue to use a reliability planning construct that is “likely,” id., to result in a blackout in the event of extreme cold.

PJM needs to move expeditiously in addressing its system vulnerabilities for a number of reasons. First, a number of generators will need to retrofit their plants or take other additional steps in order to guarantee firm fuel. These steps will take time, and thus the sooner the process starts, the better. Second, the CP program will have an impact on the incremental auctions, and the promulgation of clear rules regarding the CP program will minimize disruption to the incremental auctions. Third, parties continue to engage in retail contracting, and clarity on the CP program is necessary to guarantee that retail contracts accurately reflect wholesale capacity pricing. Fourth, generation owners are actively making decisions about whether to retire resources that have not cleared but have not yet announced retirement. Those decisions obviously will be affected by the incentives established by the CP program, and generation owners need clear market signals on which they can rely. Fifth, the urgency is only underscored by the D.C. Circuit’s decision overturning Order No. 745 and today’s order denying rehearing of that decision. To the extent that the voluntary demand response resources relied upon by PJM in January 2014 were motivated by energy market compensation, the D.C. Circuit’s decision disallowing that compensation makes it all the more important for PJM to preserve existing generation.

Accordingly, it is critical not only that PJM institute the Capacity Performance product as part of the RPM auction for the 2018/2019 Delivery Year, but also that it hold supplemental auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years. As PJM correctly recognizes in its Proposal, it must “incrementally procure a sufficient amount of capacity that adheres to the performance standards and requirements of the Capacity Performance product” in order to ensure reliability. PJM Proposal at 33. PJM cannot obtain reliability assurance for the transitional years leading up to the 2018/19 Delivery Year without an explicit high availability capacity product.

Those supplemental auctions should be nondiscriminatory and structured similarly to the auction for the 2018/2019 Delivery Year, and the full quantity of CP Resources needed to ensure reliability should be procured. For the supplemental auctions, all resources that already cleared in previous auctions (base residual and incremental) should be permitted to offer in the CP auction and effectively switch their obligation from the Base Capacity product to the CP product. This switching will naturally decrease the quantity of the base product. Further, if PJM implements a must-offer requirement for certain resources, these participants should be permitted to offer an “adder” above the previous auction price for taking on the additional obligations related to the CP product. This adder should reflect the penalty risk premium as discussed in Part II(B) above and any incremental costs required to comply with the CP obligations.

To the extent that PJM wants to phase in the penalties described in Section III(A) in rather than immediately imposing whatever it determines to be the final, appropriate, amount, Exelon proposes a rapid ramp up in the supplemental auctions to that final number. Although market participants may need some time to develop infrastructure and refine offer strategies in light of the CP program requirements, the acceleration of penalties (and concomitant incentives
for generators to create firm fuel resources) should be quick in light of the urgency of the problem faced by customers in the winter.