

Problem Statement on PJM Capacity Performance Definition

PJM Staff Draft Problem Statement
August 1, 2014



This page is intentionally left blank.

Introduction

The events of winter 2014 operations highlighted issues related to generation performance and increasing dependence on natural gas for power generation during winter peak conditions. Recent operational trends and the trend of resource mix clearing in the forward RPM auction 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. These recent trends together with PJM staff analysis regarding future reliability impacts with respect to observed generation performance, winter peak operations, fuel supply and operational inflexibility has revealed the current capacity product definition and the current set of performance incentives and penalties for Capacity Resources does not sufficiently address all that is required to ensure that operational reliability will be maintained through all seasons.

Recent industry and FERC discussion regarding concerns over 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 a reasonable cost. As demonstrated consistently by the RPM auction results, the current capacity market and capacity product definition has performed well in encouraging investment in demand resource technologies and in new gas generation. The current market has also been successful in satisfying planning criteria and meeting the installed reserve margin. While the forward capacity market structure has been successful, the current requirements for resources to be considered a Capacity Resource do not appear to sufficiently address the observed generation performance issues, winter peak operations issues and operational characteristics that are needed to ensure that system reliability will be maintained through the industry transformation that is occurring.

Today the capacity product in PJM is a commitment by a generation resource to make energy available in the PJM energy market or, in the case of demand response resources, to reduce energy consumption during certain system conditions. For generation resources, the chief obligations include:

1. The ability to deliver energy to load on the PJM system at all times, especially during system peak and emergency conditions, as demonstrated through a generation deliverability analysis.
2. The availability of energy output to energy consumers in the PJM system at prices at or below the offer caps established in the Tariff and Operating Agreement as demonstrated by submitting offers in the Day-Ahead Energy Market on a daily basis throughout the 12-month commitment period (June 1 to May 31), unless the resource is unavailable due to a forced or scheduled outage.
3. The availability of energy output to PJM if needed to maintain reliable operations during emergency conditions, which include PJM recall rights for off-system energy sales for committed capacity resources.
4. Avoiding scheduled outages during specified peak load periods and providing outage data to PJM.

If the resource is not on an outage and available to provide energy, generation capacity resources must submit both a cost-based energy offer and market-based energy offer into the PJM Day-Ahead Energy Market.

For demand response resources, the chief obligations are:

1. The ability to curtail consumption in accordance with its commitments when PJM approaches emergency conditions.
2. The provision of measurement and verification of load reductions following pre-emergency and emergency conditions as required.

The power industry is going through a significant transformation with the retirement of a large number of coal-fired resources being replaced by natural gas resources and Demand Resources. This changing resource mix creates greater operational stress on the power system as the interactions between the commodity gas market and interstate pipeline scheduling are not yet harmonized with power market operation and PJM must approach emergency conditions in order to access available Demand Resources. A more robust capacity product definition with enhanced incentives for performance and penalties for non-performance that address the following observations coming out of the Winter of 2014 issues is required to ensure ongoing reliable power system operations.

- Observed generation forced outage rates at more than three times the expected forced outage rate during winter peak period;
- A realization that in spite of poor performance, the current market rules provide insufficient incentives for resource performance and penalties for non-performance;
- Problems with fuel security and availability for both primary and back-up fuel;
- Gas supply inflexibility during winter peak conditions which led to sub-optimal price formation and unprecedented uplift payments to generation resources;
- Reduced and restricted generation resource availability due to fuel unavailability and operating permit restrictions; and
- Increasing amount of inflexible resource offer parameters that hinder optimal price formation and lead to uplift.

The purpose of this whitepaper is to clearly define the issues that must be resolved in order to ensure that PJM Capacity Resources perform as required in order to efficiently maintain reliability all year round. Specifically, this paper discusses the actual system conditions and generator performance observed during the winter of 2014, the reasons why the current system of incentives and penalties for Capacity Resources is insufficient to ensure the necessary level of resource performance, PJM staff analysis regarding the reliability implications of observed resource performance and lack of fuel security for future winter peak periods, and the gas/electric industry interactions and other factors that are resulting in restricted resource availability and flexibility during peak load periods.

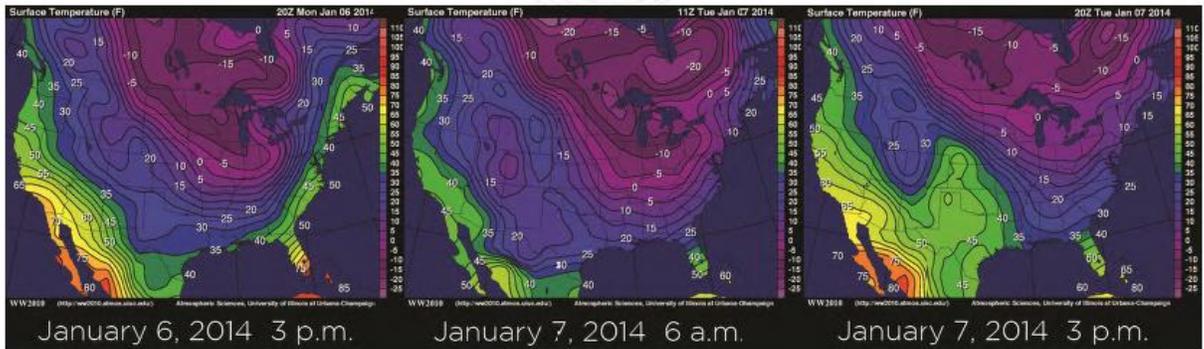
Increased Generation Outage Rates during Winter Peak Period

January 2014 was defined by several snow storms and bouts of cold weather, including the “Polar Vortex” event.

Much of the week of January 6 was quite cold, with the worst days being Monday and Tuesday, January 6 and 7. Daily low temperature records were set or tied in Chicago, Pittsburgh, Cleveland and Columbus on January 6 and in

Philadelphia, Richmond, Pittsburgh, Cleveland and Columbus on January 7. The following graphic shows how the cold weather enveloped PJM, as well as PJM neighbors, over the course of these two days.

Figure 1: Polatr Vortex



A second, longer cold weather period in January 2014 again challenged the PJM system and operators. Prolonged cold temperatures January 17 through the 29 came with a snow storm that dropped about a foot of snow on the East Coast. While there were several frigid mornings and two significant snow storms across the footprint during the latter half of the month, no one day experienced such cold temperatures across as wide an area as experienced on January 6 and 7.

Figure 2: January 2014 Minimum Temperatures: Columbus, Philadelphia, Chicago and Richmond

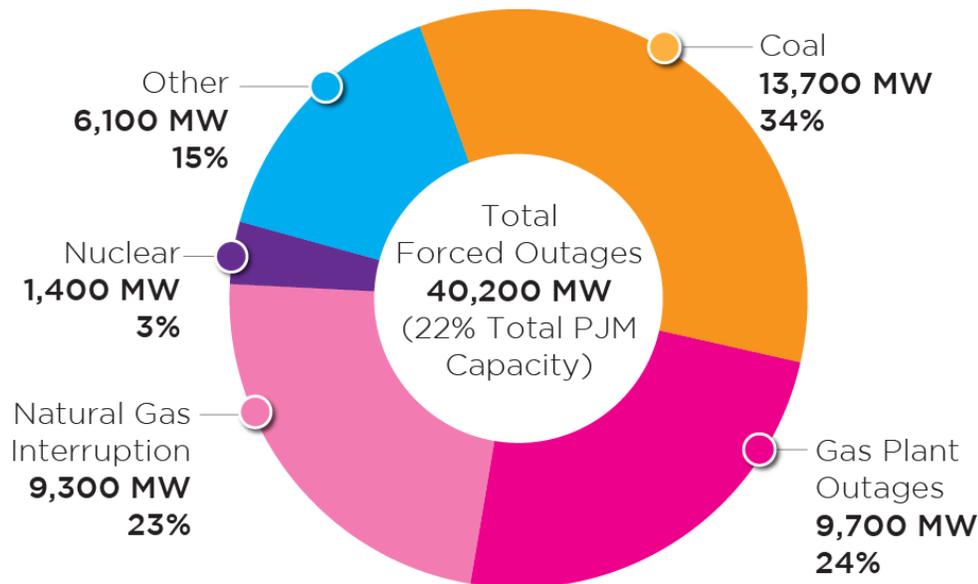


The extreme cold weather on January 6 and 7 led to higher than expected unplanned generator shutdowns and outages due to the inability of generators to start. During the latter half of January the extended period of cold

weather -- while not as extreme as January 6 and 7 -- challenged grid reliability and adequate power supplies due to extended generator run times that were out of merit order because of gas supply inflexibility, natural gas interruptions and fuel-oil delivery problems. A generator's inability to run due to any type of unexpected mechanical or fuel issue is considered a forced outage. PJM experienced very tight operational conditions and a significantly higher number of forced outages, due to both mechanical problems and natural gas deliverability, throughout January 2014 as compared to a more typical January. At the all-time winter peak at 7 p.m. on January 7, PJM experienced a 22 percent forced outage rate, which was far above the historical average of 7 percent, with a total of 40,200 MW unavailable due to forced outages.

The breakdown of forced outages by primary fuel type below shows that natural-gas-fired generators accounted for 47 percent of the unavailable megawatts split between natural gas interruptions (9,300¹ MW or 23 percent) and natural gas unit outages not related to fuel (9,700 MW or 24 percent). Coal-fired generators accounted for over 13,000² MW of outages or 34 percent. For a frame of reference, in PJM, plants with natural gas as their primary fuel account for 29 percent of the total installed capacity (in megawatts), and coal-fired plants represent 41 percent. These unavailable megawatts were due to either the generator's entire output being unavailable or a limitation on the amount of megawatts the generator could supply to the system.

Figure 3: January 7 Evening Peak (7 p.m.) Forced Outage

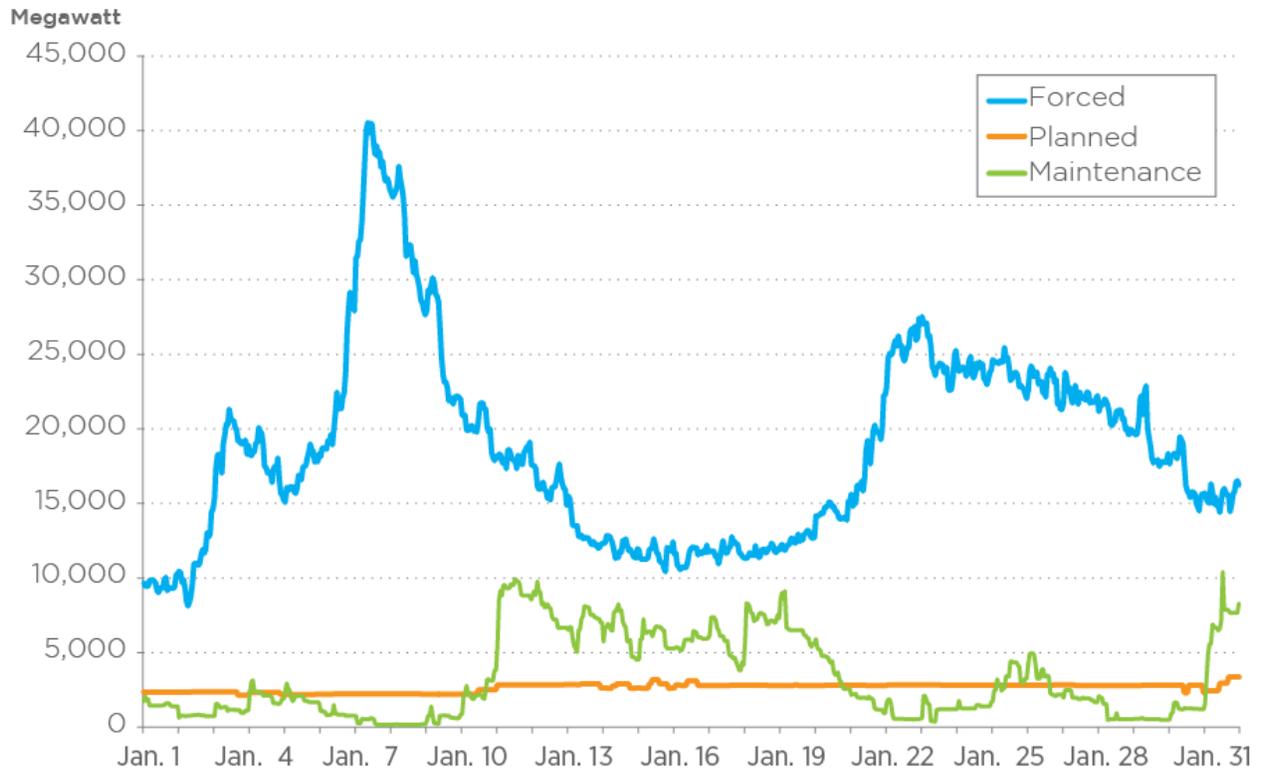


¹ The 9,300 MW value does not include coal-fired units that required but could not get natural gas to start.

² The 13,000 MW value includes coal-fired units that required natural gas to start.

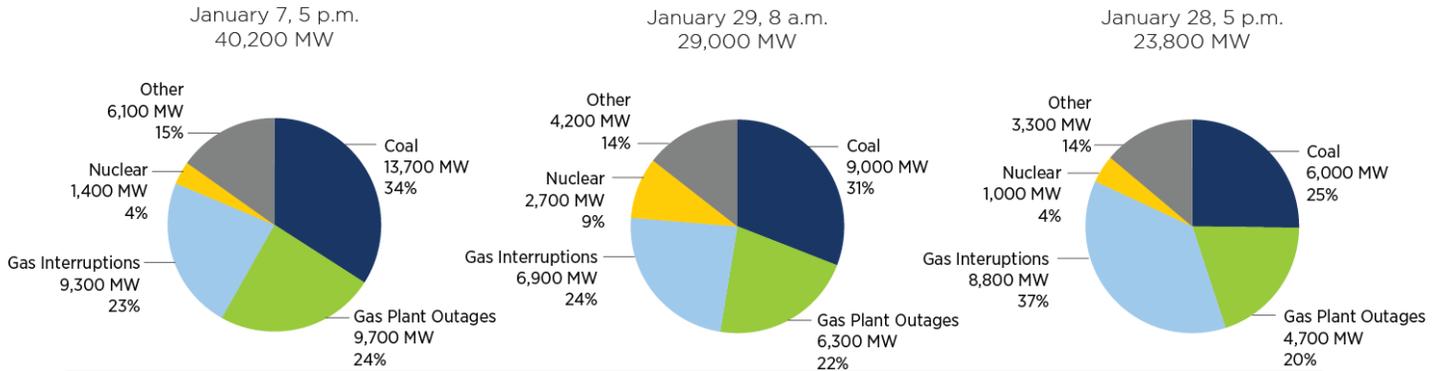
Because PJM experienced a 22 percent generation forced outage rate on January 7, similar forced outage rates were expected by PJM operations during the Winter Storm from January 17 through the 29 because of the similar forecasted weather conditions. The amount of generation available during the Winter Storm period of the month improved as compared to the Polar Vortex of January 6 and 7 but was still worse than PJM's historical average winter forced outage rate.

Figure 4: Generator Outages – January 2014



The following pie charts show a comparison breakdown of unavailability due to forced outages by fuel type for the Polar Vortex peak and the winter storms in late January. The chart below the forced outage pie chart shows the high and low temperatures for several cities across PJM for each of the three days. Conditions on January 24 and 28 were not as severe over as wide an area as during the week of January 6.

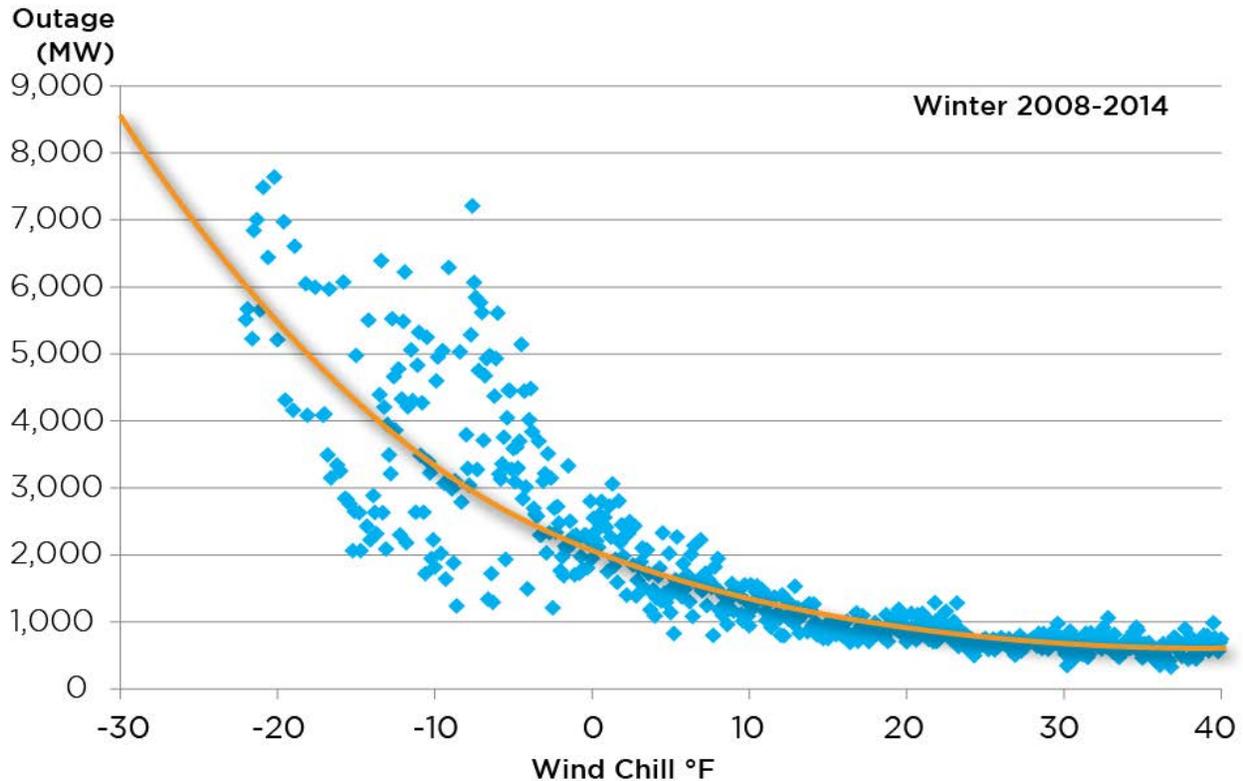
Figure 5: Forced Outages



Coldest low/high temp of the three days	January 7		January 24		January 28	
	Low	High	Low	High	Low	High
	Philadelphia	4	13	8	19	12
Richmond	10	22	11	25	14	27
Pittsburgh	-9	4	0	19	-8	7
Columbus	-7	11	0	22	-11	6
Cleveland	-11	4	-1	21	-9	7
Lexington	-4	11	-5	24	2	12
Chicago	-12	3	-6	28	-11	3

In general, PJM data show that generator outage rates can be expected to increase during cold weather conditions. As shown in the following chart which references the winters of 2008 through 2014 in the far western area of the PJM region where the coldest historic temperatures occur in PJM, generator outages increase significantly as temperatures (in this case measured as wind chill) decrease.

Figure 6: Wind Chill vs. Forced Outage – Western PJM



PJM solicited feedback from the generation owners to assess operational experiences during the January cold weather events. Generation owners reported experiencing the following issues directly related to extreme cold weather:

1. **Frozen equipment** - condensate lines, nozzles, boiler controls, fly ash transfer equipment, SCR³ and water injection systems; many freezing issues attributed to inadequate heat trace and/or insulation issues which allowed water to penetrate and freeze lines.
2. **Fuel issues** – frozen coal, coal opacity issues, fuel delivery issues (e.g. oil, gas, etc.) due to weather.
3. **Emissions equipment** – water supply for injection systems that must be operated to reduce nitrogen oxide emissions and tuning of emissions equipment that can't be simulated prior to extreme cold weather.
4. **Consumables impacts** – frozen limestone, extreme cold resulted in hydrogen seal oil system contractions causing hydrogen leaks which depleted hydrogen supply/storage.
5. **Secondary processes** - issues with systems like demineralized water systems – limited ability to make and store demineralized water used for boiler feed water make-up and injection systems.

³ SCR or Selective Catalytic Reduction is a system used to reduce NOx in combustion gas streams; water injection controls combustion temperatures to reduce NOx formation.

- 6. **Units not frequently operated** – some high cost, low capacity factor units might not have been operated since the summer peak period

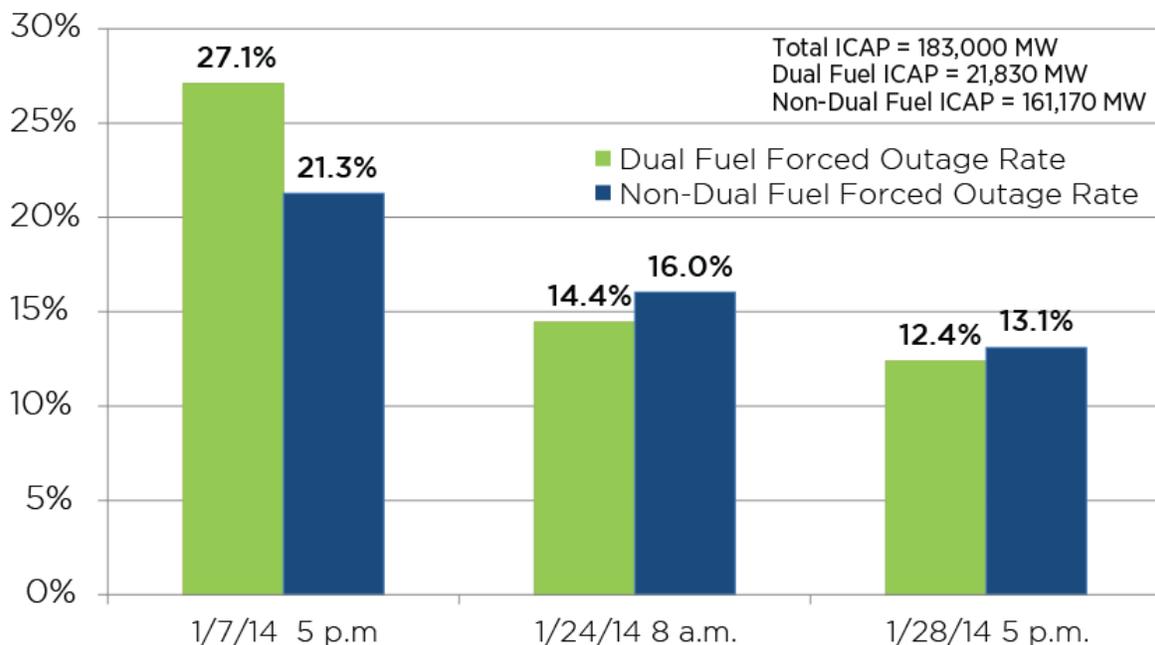
Winter Performance of Dual-Fuel Units

Some gas-fired units have the capability to use an alternate fuel (dual-fuel capability), which increases flexibility when gas supply becomes tight. While dual-fuel units increase flexibility, there were still challenges operating the units on oil. PJM requested dual-fuel generation owners unable to secure gas to operate their units on oil during the extreme cold weather events. Even with this flexibility, generation owners encountered increased failure rates for unit start-up, run-time limits related to permit-defined environmental restrictions, fuel supply challenges, and issues with dual-fuel units requiring start-up gas.

PJM coordinated with generation owners that needed to decrease the maximum run time per day for their units in order to conserve run times due to permit-defined emissions limitations. There were approximately 1,000 MW of generation with decreased run times for emission reasons.

The increase in demand for oil caused another challenge for generation owners. Many units in the Northeast switched to oil as gas became unavailable, thereby increasing demand for oil. In some cases, oil suppliers began to run low on inventory or deliveries were slow because increased demand was unexpected and available delivery trucks were limited. Generation owners found it difficult to keep oil tanks full on a daily basis and had to limit run hours for their units. There were approximately 2,000-3,000 MW of generation affected by oil supply and delivery issues. Also, some generating units running on oil experienced an increased start failure rate due to clogged fuel lines due to the units not typically being operated on oil.

Figure 7: Forced Outage Rate of Dual Fuel vs Non-Dual Fuel



Generation Capacity Resource Incentives to be Available and Operate to Cover Going Forward Costs

Generation resources do not earn energy market revenues needed to cover going forward costs when they experience outages of the type observed during the winter of 2014. Generation resources earn net revenues to cover going forward costs (or in PJM tariff terms Avoidable Costs) from three main market sources within PJM: the energy market, the RPM capacity market, and ancillary services markets. If generation resources are able to cover their going forward costs from revenue sources, they will remain in commercial operation, and conversely if they are unable to cover going forward costs they will likely retire.

In order to earn energy and ancillary service market revenues, generators need to be available to run when market prices exceed running costs, as was often the case during the winter of 2014, otherwise generation owners will miss these sources of revenues making it more difficult to earn sufficient revenues to cover going forward costs. Many generators effectively “left money on the table” when they were unable to operate. To earn capacity market revenues, in theory resources should be available in as many hours as possible, especially winter and summer peak hours when they are needed most by the system, and there are penalties for being unavailable as expected. Again, failure to be available as expected and during peak hours should lead to penalties or reduced capacity market revenue that can go to covering going forward costs

Availability is within the Generation Owner’s Control

While there may be multiple factors driving revenues and costs that are largely out of the control of generation owners (market demand, prices of competing fuels and technologies, many regulatory policies that drive cost, competitive pressure from other supplies), generation owners are in control of costs related to operations and maintenance (O&M) and other investments such as dual-fuel capability, firm gas pipeline transportation, and weatherization investments that can counter-act oft cited issues of frozen coal piles, fuel lines, and water lines among others that will allow resources to be available to operate and earn energy and ancillary service market revenues through operations and capacity market revenues through availability.

However, generation owners may choose to cut O&M costs or choose not to make investments that enhance availability as a means to manage costs. In making such a decision, the generation owner has implicitly or explicitly made a calculation that the benefits of such measures (increased net revenues) do not cover these “additional” costs. This calculus can be made on three main fronts. First, some generation owners may view the need for the aforementioned investments and additional O&M as insurance against low probability peak events such as the recent Polar Vortex in January 2014, such that the expected return is negative. Second, generation owners may be unable to reflect the costs of some of these in PJM’s markets, and while such investments may mitigate risk, there is no way to reflect these costs in supply offers and therefore price formation in PJM’s markets cannot reflect these costs. Third, competitive pressure to clear in the RPM capacity market may push generation owners to not make these investments if they feel other competitors are taking a similar strategy due to the risk of pricing themselves out of the market.

As a consequence, while generation owners have an underlying incentive to be available to earn revenues, they may not necessarily have an incentive to maximize availability during all hours and contingencies and low probability events. And while this is a rational economic decision from the perspective of the generation owner, from a reliability perspective PJM commits resources through the RPM capacity market to ensure sufficient resources are available to cover low probability, high reliability impact events. If the generation owner incentives are not aligned with reliability needs, then higher forced outage rates and a higher probability of a loss of load can occur during low probability, high reliability impact events such as winter and summer peak days, or unexpectedly hot spring and autumn outside the traditional summer peak.

Penalties for Capacity Resource Unavailability during Peaks are Insufficient

Section 10 of Attachment DD outlines the Peak Hour Availability Penalty. This section defines the peak hours as the 500 hours that occur: 1) HE 1500 to HE 1900 on non-holiday weekdays June through August (approximately 340 hours); and 2) HE 800 to HE 900 and HE 1900 to HE 2000 on non-holiday weekdays January and February (approximately 160 winter hours). Penalties are only incurred if the forced outage rate during peak hours (EFORp) is greater than the 5-year average forced outage rate (EFORd₅) of the resource. Moreover, Section 10(d) explicitly states that outages Out of Management Control (OMC) are not to be included in these outage figures for calculating EFORp. And Section 10(e) states:

“...for single-fuel, natural gas-fired units a failure to perform during the winter Peak-Hour Period shall be excused for purposes of this section if the Capacity Market Seller, or Locational UCAP Seller, as applicable, can demonstrate to the Office of the Interconnection that such failure was due to non-availability of gas to supply the unit. “

where demonstration to the Office of the Interconnection refers to qualification of the outage as OMC. For example, suppose a generator with a typical EFORd of 5 percent was unavailable for 10 out of 500 peak hours (2 percent EFORp), but those 10 hours were the most reliability critical hours when that generator was needed most would incur no Peak Hour Availability Penalty in spite of its outage occurring in the most reliability critical hours.

Incentives Created by Insufficient Peak Period Penalties

Insufficient peak period penalties as currently in the PJM Tariff provide a disincentive to make investments in generation resources to make them available during low probability, high reliability impact events.

First, the penalties for being unavailable during the pre-defined peak hours more than the 5-year average EFORd provides no incentive to make investments in O&M or infrastructure to enhance availability since there is little risk of incurring a capacity market penalty for being unavailable during reliability critical events. Given this low risk, there is no reason for the generation owner to make such investments.

Second, there is an incentive to try and characterize as many outages as OMC as possible since OMC is excused from the EFORp calculation, and provides an incentive for generation owners to hide the real cause behind an outage, or to shift the cause of an outage to a third party such as a gas pipeline. And in general, in almost all cases

lack of fuel is not OMC as the choice of gas transportation or oil delivery arrangements, installation of dual fuel, and gas interconnection to an interstate pipeline or behind an LDC city gate are business decisions well within the control of the generation owner.

Current PJM Capacity Market Rules Do Not Allow Full Reflection of Costs for Low Probability, High Reliability Events

The reflection of going forward costs or Avoidable Costs, known as the Avoidable Cost Rate (ACR) is governed by Attachment DD, Section 6.8 of the PJM Tariff. Avoidable Costs or going forward costs are the costs of being a capacity resource that can be considered **fixed annual operating expenses** that would not be incurred if a unit were **not** a capacity resource for a year.

Currently the costs of Firm Transportation for natural gas are not explicitly mentioned as being included in ACR, nor are the costs of Firm Transportation explicitly excluded. Arguably Firm Transportation is akin to a fixed O&M cost that would logically fit within ACR calculations. However, there has been a general understanding among market participants and the Independent Market Monitor (IMM) that the costs of Firm Transportation are not permitted in the ACR which goes into calculating Market Seller Offer Caps.

One way of interpreting investment in new pipeline capacity to ensure Firm Transportation is to think about this as a capital investment to improve the availability of a generation resource. Such investments under RPM and in ACR as the Allowance for Project Investment Recovery Rate (APIR) which allows for “the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures (CapEx) for which the project investment must be completed during the Delivery Year, *that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to **continue operating or improve availability during Peak-Hour Periods** during the Delivery Year.*” (emphasis added). By this definition of project investment, Firm Transportation could easily fit in under APIR in terms of its purpose.

In contrast, the cost of installing dual fuel capability, including demineralized water production and storage can be included in APIR as well as the carrying costs for fuel storage and demineralized water storage on a going forward basis can be recovered through ACR today. So if anything, there is at best uncertainty as to whether FT can be included in RPM offers, and at worst it cannot be included and biases cost recovery to dual fuel which under the current peak period penalty structure exposes gas units to penalties they would otherwise not face.

Current PJM Energy Market Rules Either Do Not Allow Full Reflection of Costs for Low Probability, High Reliability Impact Events, or Bias Decisions Away from More Reliable Solutions

The details regarding the reflection of fuel costs in energy offers can be found in PJM Manual 15, Section 2.3. Each generation owner must submit a fuel cost policy to the IMM and as part of the policy the fuel cost is either a spot fuel market fuel cost or a contract fuel cost.

According to Manual 15, the contract price for fuel must include the locational cost of fuel for the generating unit. The source used for spot price for fuel must be publicly available and reflect the locational cost of fuel for the generating

unit. ***The locational cost of fuel shall include specification of any additional incremental costs of delivery*** (emphasis added).

Regardless of spot or contract purchases of fuel, fixed cost or the costs of leased equipment must be excluded from the cost. As a matter of course, costs of delivering fuel that are volumetric can be included in fuel costs as cited in Section 2.3 of Manual 15:

...the "charge per unit of fuel delivered" should be included in the Free on Board (FOB) delivered cost or in the calculation of the "other fuel related costs" as per the documented fuel pricing policy.

The implications for the types of costs that can be included in energy offers are straightforward. In the case of gas the cost of IT are naturally included as they are volumetric. For bundled gas commodity and transportation from asset managers or marketers, Firm Transportation is being bundled with gas volumetrically and can be included in fuel costs while stand-alone Firm Transportation cannot be included. For other fuel types, the costs of trucking, rail, or barge costs on a volumetric basis can be included while any fixed costs to reserve transportation cannot be included.

Additionally, energy markets offers in PJM are currently in place for all 24 hours of the day, and cannot be changed once a unit has been committed or dispatched by PJM. However, commodity gas prices, that may include bundled transportation, can change by hour throughout the operating day due to changing gas market conditions. The inability to reflect different hourly offers means that one energy offer price must remain in place over two different gas days (see discussion below), and that units needed in real-time cannot update their offers to reflect changing gas prices if they have not secured commodity gas prior to being dispatched. Faced with a choice of possibly running at a loss or taking an outage for which there are scant penalties, a gas unit will simply choose to take the outage rather operate at a loss which could threaten reliability.

Overarching Direct and Indirect Incentives for Enhancing Availability and Market Implications

Regardless of the timing of gas nomination schedules relative to power market clearing, there exists no direct incentive to secure Firm Transportation on a standalone basis for gas fired units as there is no clear place to reflect the cost of Firm Transportation. If anything the current market rules are biasing transportation choices toward "short-term Firm Transportation" bundled with commodity. In fact there is no incentive to purchase Firm Transportation through released transportation capacity markets as it cannot be included in energy offers because it is considered a fixed cost.

The end result is that with a greater shift toward gas-fired resources there is no incentive for generators to sign up for Firm Transportation and expand available pipeline capacity, and then greater uncertainty of which resources will be available based on the ability to secure bundled commodity and transportation on a short-term basis.

Using "short-term spot Firm Transportation" reduces the risk to generators for holding Firm Transportation that cannot be reflected in price formation and may not have value beyond relatively few hours per year, and in theory should increase the risk of non-performance penalties during the peak period, but there is really little risk of incurring the penalty. The reliance on short-term firming of transportation increases peak period energy market price volatility.

In the absence of peak period incentives against dual fuel capability for gas units, there is then a bias toward dual fuel capability even with the almost certain restrictions on run times associated with Title V operating permits. If there were sufficient peak period penalties, then dual fuel reduces the risk of these penalties and in some sense places a ceiling on energy market price volatility at the price of back-up fuel which tends to be fuel oil.

Overall, the current set of penalties and incentives will result in lower availability during low probability, high reliability risk peak events and increased energy market price volatility during such events due to spikes in fuel prices and reduced generator availability.

With the proper incentives for availability and performance and the ability to reflect costs in PJM markets, there may be higher capacity market costs, but this should also result in reduced volatility during tight supply and demand conditions associated with low probability, high reliability risk events.

Fuel Security and Reliability

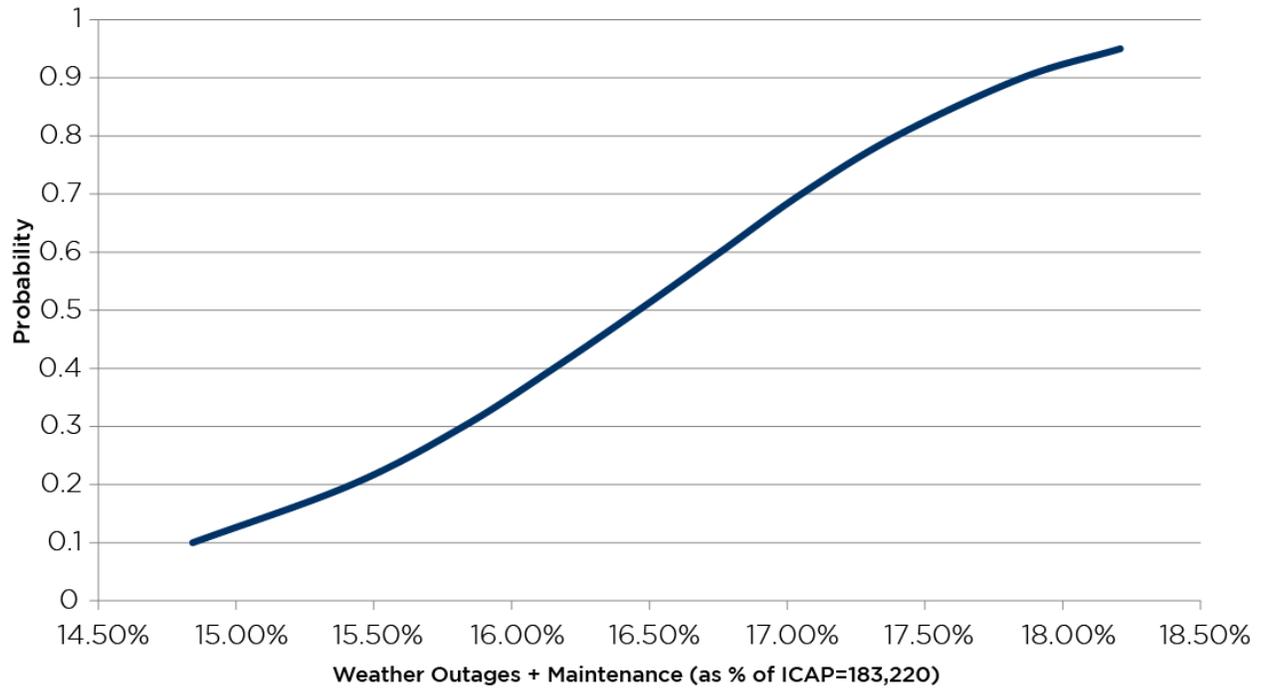
Given the extremely high loads and poor generator performance that occurred in January 2014, PJM performed analysis to assess the system loss of load risk in each of the next two winters. This analysis is based on the following assumptions:

1. PJM experiences a 90/10 winter peak load level, one that has a probability of occurrence once every ten years (consistent with the actual load experienced on 1/7/2014)
2. PJM winter generation reserves include all generators within the PJM footprint and external generators that have committed to PJM through RPM or FRR
3. Demand Resources (DR) are not available in the winter

The figure below shows the study results for the winter of 2014/15. The figure plots the probability of a loss of load event on the winter “90/10” peak day against the generator outage rate due to weather-related outages (i.e. outages that are caused by the extreme weather and are beyond the normal expected outage rate of about 7 percent). For *example*, the PJM total outage rate on January 7, 2014 was 22 percent, or 15 percent above the expected outage rate of 7 percent. A 15 percent outage rate over and above the 7 percent expected outage rate on the figure below indicates about a 10 percent probability of a loss of load event for the 2014/2015 Winter peak.

This figure indicates that, should a Polar Vortex event occur again in the winter of 2014/15 (a 10 percent probability event), PJM may be at an acceptable level of loss of load risk given the generation reserves that are committed for the 2014/15 Delivery Year. Even with the additional 15 percent outage rate that occurred on January 7, 2014, the loss of load probability remains only about 10 percent.

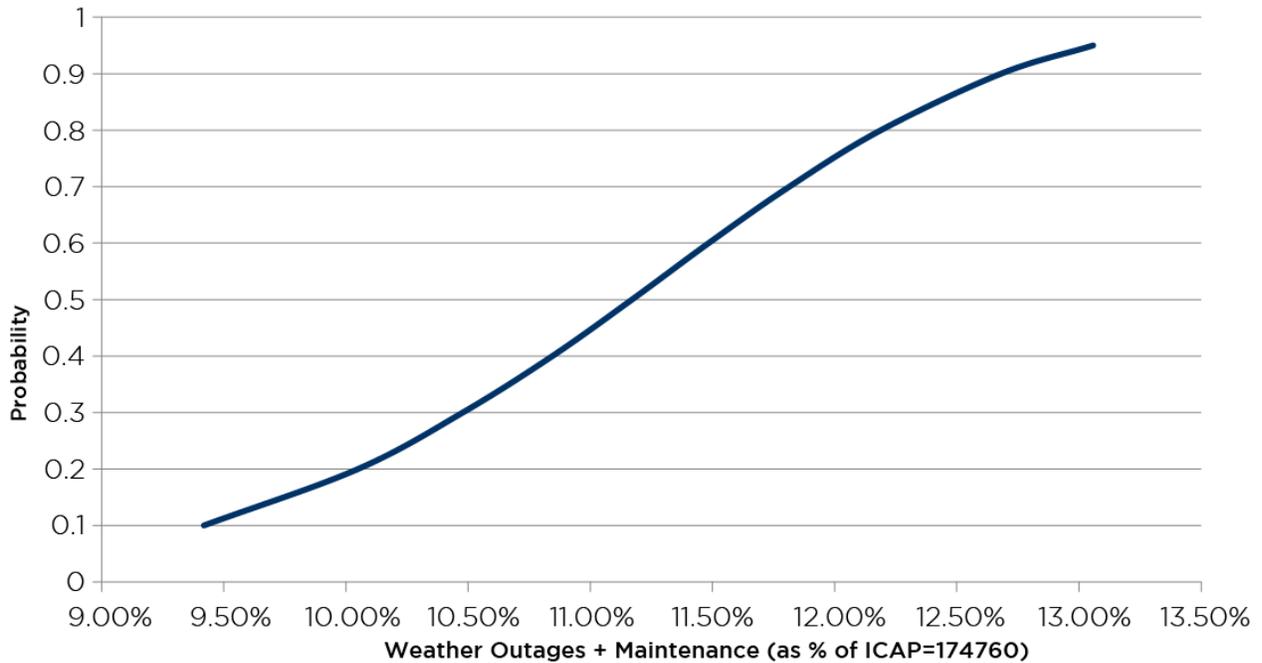
Winter 2014/2015



PJM generation reserves are projected to decrease by about 8,500 MW between the winters of 2014/15 and 2015/16 due primarily to generator deactivations. This lower reserve margin has a significant impact on the 2015/16 winter loss of load risk as shown in the figure below. This graph indicates a much greater reliability concern than for the winter of 2014/15.

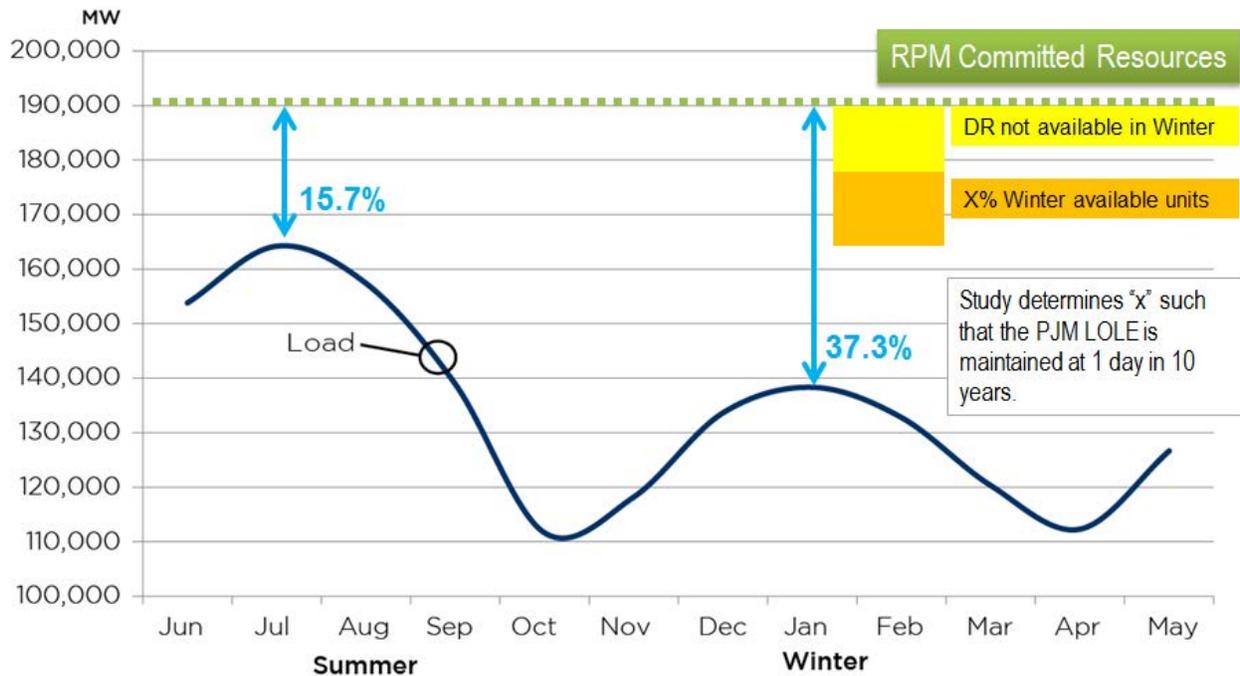
If Polar Vortex conditions occurred in 2015/16 and outage rates were as high as PJM experienced in January, 2014 - 15 percent over and above the expected 7 percent forced outage rate -- the study results indicate PJM would almost certainly experience a loss of load event.

Figure 8: Winter 2015/2016



In addition to examining each of the next two winters, PJM is also performing studies to evaluate the balance between summer and winter loss of load risk. To understand this analysis, it is necessary to first describe PJM's general approach in performing Loss of Load Probability (LOLP) studies. The PJM Installed Reserve Margin (IRM) is established based on an LOLP study that models the full, 12-month Delivery Year. The study's methodology is depicted in the figure below. Given the load profile of the entire year, the study determines the amount of resources that must be committed to PJM year-round (the green dashed line) to satisfy the LOLP standard of "one day in ten years." The level of required resources is expressed as a percent of the summer peak load (in this case 15.7 percent). As the figure indicates, the 15.7 percent summer reserve margin results in a winter installed reserve margin of 37.3 percent.

Figure 9: Summer vs. Winter Loss of Load Risk



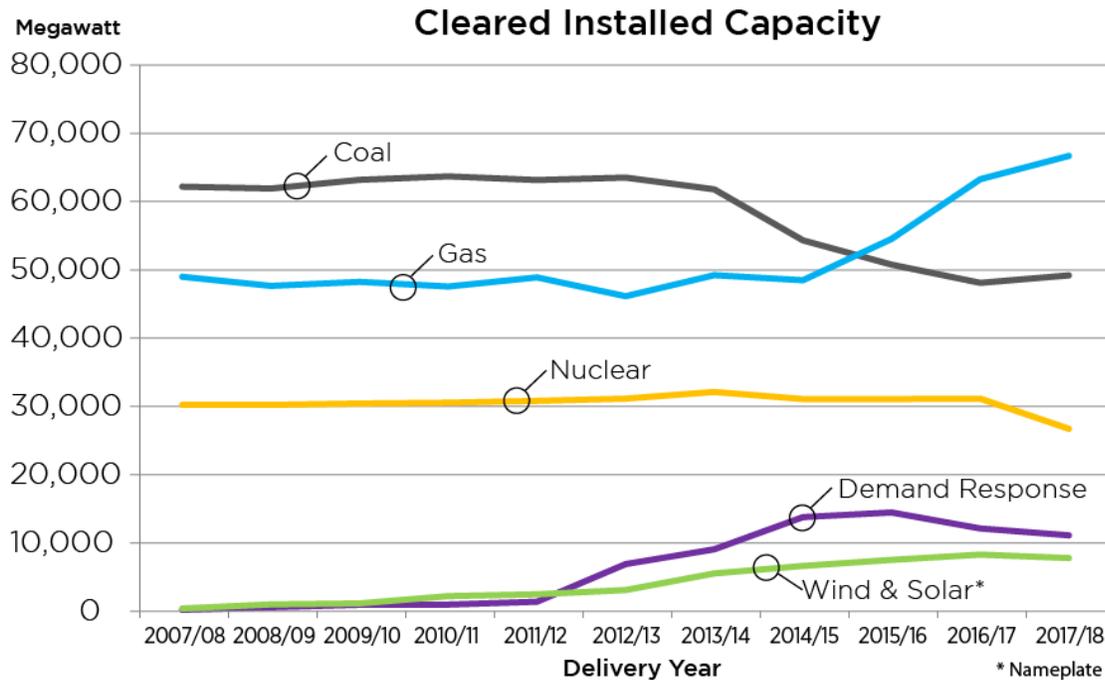
The full 37.3 percent winter reserves, however, are not required to maintain the “one event in ten years” reliability requirement during the winter period. Some amount of resources, indicated by the yellow and orange rectangles in the figure, can be unavailable on the peak winter week without compromising PJM reliability. The yellow area represents the amount of summer only (i.e. – Limited and Extended Summer) Demand Resources and is capped per RPM auction rules. Summer only DR is not obligated to interrupt in the winter season. PJM is in the process of conducting further analysis to determine the size of the orange area at which the “one day in ten years” standard is not satisfied. (The orange area represents resources, beyond summer only DR, that are unavailable at the time of the winter peak).

Performance data from January, 2014, clearly indicate that, under extreme winter conditions, the amount of unavailable generation can exceed 20 percent of the total generation fleet. As discussed in other sections of this whitepaper, these high levels of generator outages are due to many factors including fuel unavailability and mechanical failure. Gas-fired units, in particular, are subject to fuel interruptions during periods of extreme temperature.

As indicated in the figure below, PJM’s dependence on gas-fired units has increased dramatically in recent years such that gas is expected to displace coal as the most common fuel type in PJM by the 2015/2016 Delivery Year. Unless PJM changes the performance incentives and penalties for non-performance and ensures the costs of securing gas through FT arrangements can be reflected in PJM markets on an equal footing with dual fuel capability, gas-fired forced outages are sure to increase during the winter peak period. The penalties, terms, and conditions for non-performance would need to be sufficiently high such that it is attractive to reflect the costs of securing fuel to run

in all of PJM's markets. Moreover, such penalties would also incentivize other non-gas generation resources, which accounted for more than half of all outages on January 7th, to make investments needed to ensure operation under the most extreme of weather conditions.

Figure 10: Cleared Installed Capacity



Lack of Coordination between Natural Gas Commodity and Transportation Markets and the PJM Electricity Market

It is well known that there is a lack of coordination between the timing of scheduling natural gas transportation and the clearing of PJM's Day-Ahead Energy Market. Today timely transportation nominations are due more than 3 hours before day-ahead market commitments are known. Moreover, the timing of the electric day (12 a.m. EPT to 12 a.m. EPT) encompasses parts of two gas days, where the gas day is (10 a.m. EPT to 10 a.m. EPT). For generators holding Firm Transportation, waiting until the evening nomination cycle when day-ahead commitments are known may result in the desired receipt and delivery point being unavailable. For generators using Interruptible Transportation (IT), even if transportation is nominated and confirmed, it can be "bumped" up through Intra-day 1 (ID 1) Nomination cycle, known by 3 p.m. EPT and starting at 6 p.m. EPT of the current gas day, meaning gas supply can be interrupted one-third of the way through the gas day. Once a scheduled confirmed IT schedule makes it through ID 1, it cannot be "bumped" or interrupted.

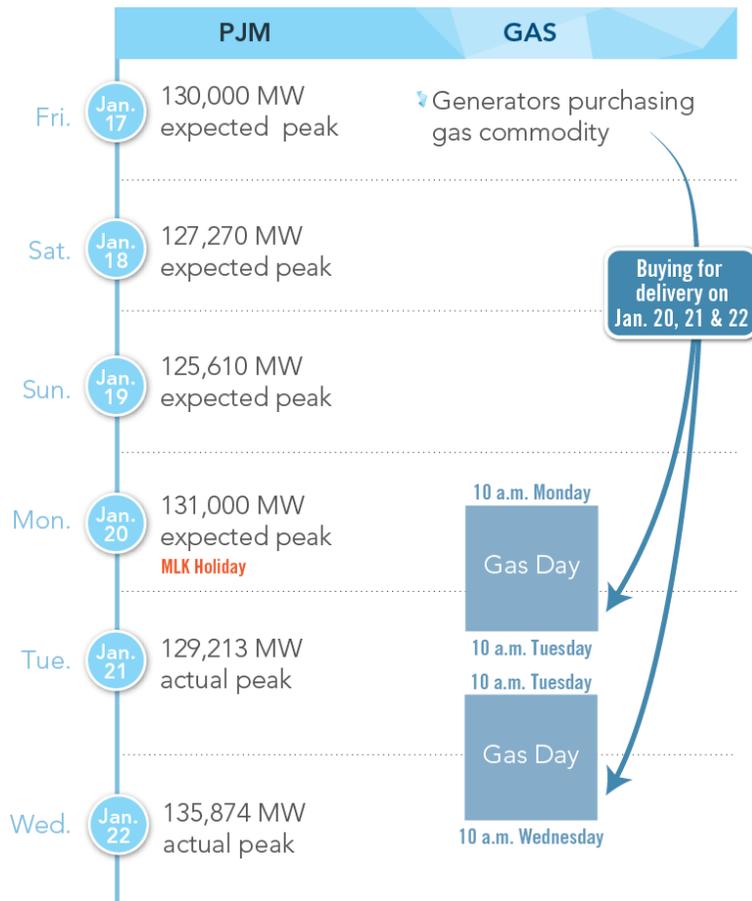
Operationally, during winter peak seasons, it is common practice for pipelines to issue Operational Flow Orders that hold gas generators to a ratable hourly take (meaning consistent, hourly quantity of consumption of gas from the pipeline) over each of 24 hours, reducing gas unit flexibility unless there is an Operational Balancing Agreement (OBA) in place between a pipeline and generator to allow deviations from ratable takes for a price. Moreover, there

are about half of PJM's gas-fired resources that are connected to the gas system behind an LDC city gate. In many cases, LDC tariffs have provisions that define temperature triggered restrictions that result in the interruption of gas supply to the generators so that pressure on the LDC pipelines can remain within tolerances.

The gas commodity market timing also is not in synch with PJM market timing. During weekdays, purchases in the gas commodity market occur prior to timely nominations, and gas purchases would need to be made prior to knowing day-ahead commitments. However, this unsynchronized timing is exacerbated on weekends where three-day strips (for Saturday, Sunday and Monday) are the most commonly offered and purchased contract on Fridays, and even into Tuesday on a long, holiday weekend. While PJM staff discussion with gas marketers and some generators indicate single day contracts over the weekend are available, they are more expensive and more difficult to find. The mismatch between gas commodity and power market timing and institutions can result in what are normally low cost and highly flexible generators becoming high cost and extremely inflexible generators, if they are available at all. At times, PJM may be required to provide generator owners with notice prior to the Day-Ahead Market that the units are needed for reliability. For example, over a three-day holiday weekend period PJM may have to notify the generator owner as early as 9:30 a.m. EPT on a Friday to be prepared for the run times needed from Saturday morning through Wednesday morning (see graphic below).

During the winter of 2014, these market timing issues were further exacerbated by the three-day holiday weekend from January 17 through the 21. High demand for electricity was expected for the Tuesday and Wednesday mornings after the Martin Luther King Jr. Day on January 20, which coincided with the Tuesday-Wednesday 10 a.m. to 10 a.m. gas day. Generation owners told PJM that in order to ensure they had natural gas for Tuesday and Wednesday mornings they needed to know from PJM on Friday, January 17 whether their units would be scheduled to run. In some instances these units were only needed to cover the morning peak from about 5:00 a.m. to 9:00 a.m., yet the units had to buy 24-hours' worth of gas. PJM's needed to make these unit/gas scheduling requests outside of the Day-Ahead Energy Market increased the level of uplift (out of market) payments in the latter half of January. These terms and conditions requiring multi-day commitments from generators was significantly at odds to the traditional Day-Ahead Market commitment and, along with the record high gas prices, increased the level of uplift.

Figure 11: Timeline.



Reduced and Restricted Availability of Generation and Demand Resources

In February 2014 PJM solicited feedback from generation owners about the reasons generation resources are offered into PJM with offer parameters that are less flexible than the actual capability of the resource such as long startup and notification times, higher economic minimum output values, and extended minimum run times. The common themes in the responses are listed below.

1. Fuel procurement restrictions; primarily natural gas.
2. Environmental limitations that limit the total run hours for a generation resource.
3. A lack of compensation for resource flexibility

In addition to the responses received from generation resource owners, PJM offers the following facts as additional key drivers of decreased capacity resource flexibility:

1. A shift in the supply curve has rendered resources designed to be base load into the role of peaking resources.
2. Reductions in staff at some generation sites to minimize costs have negatively impacted the operational flexibility and availability of some resources.

3. The increased emergence of Demand Response (DR) as a capacity resource in PJM despite its availability and flexibility limitations that has increased competitive pressure on generation resources leading to cuts in staffing and O&M costs.

All of these drivers contribute to a reduction or restriction in the availability and flexibility of capacity resources in PJM. This decrease in availability and flexibility results in inefficient grid operations because resources must be operated during times when they are not needed to ensure that they can be online when their energy production is required. The unnecessary energy injections during times when such resources are not economic leads to reduced energy prices as units being run due to operating limits are treated as price takers resulting in increased uplift payments.

The most recent example of the impact of the drivers listed above, specifically regarding fuel procurement restrictions, was in January 2014 where many gas-fired resource owners had difficulty with natural gas procurement largely due to either extremes prices or contractual terms and conditions (ratable takes, etc.). The two most common complications were 1) the perceived need to procure gas for multiple days, multiple days in advance, to ensure delivery on the desired date and, 2) the need to procure gas for all 24 hours of a given day at a peak burn level (i.e. a ratable take). The first issue, regarding gas procurement for an extended period to ensure availability on a desired date, often resulted in PJM communicating dispatch instructions multiple days in advance of the operating day for which a unit was anticipated to be necessary to run. This effectively increased the notification time to something like 48 hours on what would otherwise be a flexible combined cycle resource. The second issue of ratable takes required resource owners to purchase enough gas to run their resource at the maximum output anticipated for the day, for the entire 24 hour period of the day. In order to meet these contractual, ratable take requirements, resource owners indicated to PJM that they needed to operate at the same output level for a 24 hour period which effectively eliminated the dispatch flexibility of the resource because it had to run at the constant output to ensure its costs would be recovered, and forcing the resource's minimum run time to 24 hours.

Availability and flexibility concerns with PJM's capacity resources are not unique to generation resources. Demand Resources have been eligible to compete as Capacity Resources in RPM since its inception in 2007. While the goal of RPM was to create an arena for competition between all resources capable of providing capacity in PJM, it permitted demand response resources to collect the same capacity payment as a generation resource with much lower availability requirements. In recent years PJM has made changes to the requirements for demand response resources in the RPM by creating additional products such as Limited, Extended Summer and Annual DR to incentivize increased availability of demand resources. However, the most recent BRA for the 2017/2018 Delivery Year cleared only 1,489.4 MW of Annual DR. That amount represents less than 14 percent of the total DR cleared for that Delivery Year. The remaining 9,485.4 MW (86.4 percent) of DR cleared in that BRA have significant availability restrictions which basically render them available only during the summer. Further, the summer only DR products cleared with a very small price difference from that of Annual resources, with no discount for Extended

Summer resources and only a \$13.98 discount for Limited resources in the vast majority of the PJM region⁴. This summer only DR represents only about 5 percent of the total PJM capacity committed for that year, it is completely voluntary outside of the summer and therefore impossible to rely upon outside the period from May through October from a reliability perspective.

Increasing Amount of Inflexible Resource Offer Parameters

In order to better optimize more expensive, less efficient, generation assets – some generation resource owners have chosen to decrease staffing at sites whose run hours have either decreased over time due to economics. This was reflected in the business rule changes in 2012 that allowed unit owners to manage startup and notification times in excess of 24 hours. During recent summer days, the amount of generation capacity with startup and notification times greater than 24 hours has exceeded 5,000 MW. Some units have also communicated limited run hours due to environmental restrictions. Under reduced staffing levels, PJM has seen the notification time of some resources increase dramatically, sometimes up to multiple days, and results in a generation significantly reduced resource availability and flexibility.

Until recently, PJM's practice has been to schedule longer lead time resources as economically as possible when it believed that scheduling such resources would be economic and not create additional uplift payments. This practice however is imperfect because scheduling resource multiple days in advance requires reliance on forecasted data that is less and less accurate the further from the operating day it is determined. Following the winter of 2014, PJM has all but eliminated this practice because it could lead to additional uplift payments to resources scheduled through the normal market procedures (the Day-Ahead Energy Market and Reserve Adequacy Commitment) and does not decrease the incentive for long lead time resources to maintain long lead times because PJM was committing them and ensuring they recovered their operating costs even when they weren't economic.

Conclusion

PJM believes these issues should be addressed within the current capacity market structure. The requirements for capacity resources should be refined and the incentives and penalties related to performance should be strengthened. In a forthcoming (part 2) draft whitepaper, PJM staff will propose a detailed draft solution for stakeholder consideration and comment.

⁴ The PL zone was the only exception, where the Extended Summer clearing price was \$66.02 less than that for Annual, and the Limited clearing price was \$80.00 less than Annual.