Impact of Coal Plant Retirements on the Capacity and Energy Market in PJM

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INTRODUCTION

It has recently been observed that U.S. electricity providers are announcing the retirement of coal generating assets at an unprecedented rate. In just the past few months alone, more than 6 gigawatts (GW) of announced retirements or extended shutdowns have been attributed to compliance costs associated with U.S. Environmental Protection Agency (EPA) regulations. The Mercury and Air Toxics Standards (MATS) and Regional Haze programs are cited as the most common reason for the decisions. While MATS has a prescribed compliance deadline of April 2015, coal asset owners are also faced with weighing their operations in light of historically low natural gas prices. These retirements will have particular impact on the Pennsylvania-New Jersey-Maryland Interconnection (PJM), a competitive electricity market stretching from the east coast and mid-Atlantic to Northern Illinois that is projected to have close to one-half of the retirements.

While coal has long been a major and dependable source of power throughout the United States, the economic realities of regulatory compliance and cheaper, cleaner alternative fuel sources is forcing management to consider accelerating plant retirements in many areas. In competitive electricity markets like PJM, generating capacity is “bid” into the energy market each day. If a coal generator’s bid cost is higher than those of competing generators, it is likely that the coal generator will not be chosen to provide electricity in the energy market. When this is the case, the generator has to rely more on the revenue provided by the capacity market in PJM or revenues that may have been negotiated through some type of contract.

With close to 28 GW of coal-powered generation capacity announced to be retired nationwide by 2020, and with up to another 10 GW projected to be retired based on low natural gas prices over that same period, this lost generating capacity could have significant impacts on reserve margins. With typical utility reserve margins near 15 percent, a utility with an obligation to serve 1,000 megawatts (MW) needs to maintain 1,150 MW of resources to safely supply power load. Since a significant amount of concentrated coal generating capacity is being removed from the system, the need for new capacity should come earlier than previously expected, with the market reaching equilibrium in 2015.

The new capacity needed to meet the reserve margins will come from existing assets in other areas where load obligations have decreased and there is excess capacity, or via the construction of cleaner, more efficient technologies. Repowering of existing coal-fired power plants to gas-fired combined cycles will also be an option. With natural gas prices projected to remain well below their historical average in the near future and reduced profits available in the energy market, many types of electricity providers with higher fixed costs will move toward capacity payments, either through an administrative market like the one in which PJM operates or via contracts. Black & Veatch believes that the retirement of many coal generators will increase the capacity revenue streams in many administrative markets, providing incentives for the development of new capacity resources. In addition, certain areas within PJM should separate into “pockets” and provide higher capacity prices than the remainder of PJM, providing incentives for new construction or repowering of generation resources, such as combined cycles and combustion turbines.
The change in resource mix as coal generation is replaced by natural gas generation would likely have an impact on the energy market prices as well.

This paper addresses the probable impact of the coal plant retirements on the PJM capacity and energy market for 2013 to 2020.

PJM OVERVIEW

Background

The PJM is a Regional Transmission Organization (RTO) that manages the reliability and dispatch of the world’s largest centrally dispatched electric system. PJM coordinates wholesale electricity in all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The area under PJM control serves a population of approximately 51 million, comprising installed generation of around 170,000 MW over 56,350 miles of transmission lines.

The primary responsibility of PJM is the continuous monitoring and control of the reliable operation of the transmission grid serving the PJM area. Reliability is maintained by managing electricity supply and demand balance through the direct and indirect control of generating assets owned by power producers and by adjusting import and export transactions. Power producers are paid for their operation through competitively traded power markets managed by PJM and, to the extent they qualify, ancillary services. PJM is also responsible for monitoring the wholesale market to ensure that the market is operating competitively and that no market manipulation occurs.

Load and Resources (2013 to 2020)

According to information available on the PJM website, the total coincident peak demand for PJM is expected to be approximately 153.15 GW in 2013 and is expected to increase to 169.58 GW by 2020.

As can be seen from Figure 1, the approximately 75 GW of existing coal plants in PJM constitute approximately 39 percent of the total installed capacity in the region. Coal plants provide baseload energy along with nuclear units that make up about 17 percent of PJM’s installed capacity. Natural gas-fired combined cycle and combustion turbine units make up 26 percent of the total installed capacity in the region.

Figure 1

Resource Mix in PJM Interconnection in 2012

Source: Black & Veatch
From a generation standpoint, as can be seen on Figure 2, coal plants account for approximately 49 percent of the annual energy generated from all power plants in PJM, while nuclear power plants contribute approximately 31 percent of the regional annual generation.

The capacity and generation mix of the region indicate that PJM historically has had a predominance of baseload resources and generation. Coal units made up the bulk of this capacity and generation. As in the past, coal has generally been cheaper than natural gas, and coal prices have been less volatile compared to gas prices; PJM has historically experienced relatively low and stable energy prices.

**Capacity and Energy Market Structure**

PJM has a structured energy and capacity market. In the energy market, generators bid into the PJM Day-Ahead (DA) Market. Revenue received by generator is based on Locational Marginal Price (LMP) at the injection point and the amount of generation injected into the transmission system. PJM has a well-developed auction market for capacity. Entities serving load in PJM are required to maintain adequate capacity resources to serve their peak demand and reserves as governed by the Reliability Assurance Agreements for each reliability region in PJM. These entities may acquire capacity through several means including bilateral transactions, long-term self-scheduling and/or participation in the Reliability Pricing Model (RPM) capacity market. RPM is PJM’s most recent policy developed to reduce price volatility and secure this region’s growing electricity needs with long-term voluntary investments in building capacity, securing local generation and improving the grid. The model is based on an algorithm that optimizes reliability and minimizes the cost of the needed capacity given generation possibilities and current conditions of the grid. The aim is to pay higher prices for capacity in areas with little excess capacity in an attempt to create incentives either to build generation in these areas or improve transmission.

The RPM rules require generating resources in the energy market to bid into the capacity market, and load is required to purchase capacity from the market (or secure capacity rights through other means, such as bilateral transactions) for three years into the future. The RPM is designed to produce bid prices that reflect the annual fixed carrying costs of new capacity entering the market less PJM-administered assessments for energy and ancillary services revenues. The supply and demand curve for a typical RTO base residual auction is presented on Figure 3 for illustrative purposes.
KEY REGULATORY CHALLENGES FACING COAL UNITS

All utilities across the United States are currently facing a confluence of EPA regulations, namely, MATS and Regional Haze. All these rules have stringent regulatory measures to curb emissions of pollutants from power plants. Although the Cross-State Air Pollution Rule (CSAPR) has been vacated by the court, the MATS and the Regional Haze programs are on track, and existing and future coal plants are expected to be greatly impacted by these regulations.

MATS regulates emissions of hazardous air pollutants (HAPs) from five categories of coal- and oil-fired electric generation units. The EPA proposed rule was released in March 2011 and finalized in December 2011; compliance would begin in 2015. The rule calls for strict emissions limits to be based on the top 12 percent of performing sources and does not have any provisions for trading of allowances. Emissions limits are to be strictly applied to each affected unit, and noncompliant units would need to have new emissions control equipment installed or be retired (no trading allowed). Numeric limits are proposed for mercury (Hg), metals (total, individual or particulate matter [PM], and acid gases (hydrochloric acid [HCl] or sulfur dioxide [SO\textsubscript{2}]).

The objective of the Regional Haze Program is to improve visibility at Class I areas through reduced emissions. Reasonable progress goals (RPGs) are set to achieve natural background levels by 2064. States are to determine the RPG glide path and State Implement Plans (SIPs), and impose controls. EPA is required to approve and finalize SIPs in 2012. Eligible sources would be to install Best Available Retrofit Technology (BART) to reduce emissions in the initial control period. The EPA plans periodic
reassessments and revisions of SIPs to impose additional controls. This rule mostly affects power plants located in the Western Electricity Coordinating Council (WECC) region.

In addition to the MATS and Regional Haze programs, other key environmental regulatory drivers that could impact fossil fuel-based power plant operations are the Clean Water Act 316(b) and the Coal Combustion Residuals Act. Additional retrofit requirements associated with the Clean Water Act 316(b), Coal Combustion Residuals and other effluent discharge restrictions are not expected to have additional impacts on plants as estimated under MATS and Regional Haze, and therefore, the impacts have not been discussed in this analysis.

MODELING APPROACH

The modeling work for this study is based on the Black & Veatch proprietary Energy Market Perspective (EMP) Model. The EMP provides a 25-year fuel, energy and capacity outlook for all U.S. electric regions including PJM.

The EMP is underlain by a series of fundamental structural energy market models as shown on Figure 4. Black & Veatch utilizes its Integrated Market Model (IMM) as a basis for the current industry structure as well as a starting point for long-term analysis. In order to arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, natural gas finding and development costs, and gas pipeline expansions. Black & Veatch uses these data in a series of vendor-supplied and internally developed energy market models to arrive at its proprietary market perspective.

From the EMP process, Black & Veatch has developed an independent forecast of every North American wholesale electricity market. This zonal analysis of the regional markets incorporates the results of Black & Veatch’s assessment of market-based capacity additions and retirements, the impact of potential greenhouse gas legislation, and the interzonal transmission transfer capabilities implicit in the existing transmission system and the new transmission facilities needed to facilitate renewables development.

Black & Veatch’s market perspective considers the resource adequacy value of capacity in each market with a "Net Cost of New Entry" process, and to the extent that forecasted energy prices are insufficient to induce reliable levels of generation, Black & Veatch calculates the equivalent of a capacity price forecast that “fills the gap” between energy market net operating revenues and new entrant revenue requirements. This approach is structurally consistent with the administrative capacity markets in Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO) and PJM and is reasonable to use as an indication of value in other markets where there are no administrative capacity markets.

Figure 4 also provides a snapshot of the modeling approach. For modeling the energy and capacity markets, Black & Veatch uses the PROMOD model, which it licenses from Ventyx.
RETIREMENT ANALYSIS

In order to understand the impact of the EPA regulations, Black & Veatch used a five-stage approach as follows:

- **Stage 1** – Retire all announced coal units on the announced date.
- **Stage 2** – Dispatch units with current fuel costs and no emissions allowance costs to identify and retire coal units that fail to make a profit in three consecutive years until 2015, before MATS comes into effect. The units that fail this stage of analysis will be retired in 2015.
- **Stage 3** – Assess the remaining national fossil-fuel generation fleet at a unit level to determine what controls, if any, would be required to be put on each of those units to make them compliant with MATS. This analysis was done with the help of other professionals from Black & Veatch’s management consulting division.
- **Stage 4** – Units that were more than 50 years old and needed new sulfur oxide (SOx) and nitrogen oxide (NOx) emissions control equipment to be put on for MATS compliance were instead retired at the end of 2015 because it was assumed that utilities would be hesitant to make heavy investments on old coal units that would reach end of life in the near future.
- **Stage 5** – For the remaining units, retrofit costs were estimated, and the model was run to dispatch units to identify and retire coal units that fail to make a profit in three consecutive years until 2019. The units that fail this stage of analysis will also be retired in 2015.

On the basis of this retirement analysis and as shown on Figure 5, approximately 19.7 GW of coal units are likely to be retired by 2020, out of which about 16 GW are expected to retire by the end of 2015 before MATS compliance comes into effect. These retirements account for approximately 26 percent of the existing coal units in PJM.
Because of these retirements and simultaneous load growth in the region, PJM would need additional capacity in 2015. On the basis of the different operating costs and economic parameters for different technologies, combined cycle units were primarily chosen to replace the retired units.

Figure 6 shows the capacity mix in 2016, after 16 GW of coal units are retired and replaced with natural gas-fired combined cycle units.
Compared to the current resource mix for the region as seen on Figure 1, Figure 6 shows that coal capacity has decreased to 32 percent from 39 percent while combined cycle capacity has increased from 13 percent to 16 percent.

**Figure 6**
Resource Mix in PJM Interconnection in 2016
*Source: Black & Veatch*

**IMPACT ON PJM ENERGY AND CAPACITY PRICES**

Removal of coal plants can have a measurable impact on capacity prices in PJM. Typically, coal plants bid into the capacity market at very low prices, primarily driven by the fact that they are baseloaded units and can recover much of their revenue requirements in the energy market. To illustrate the effect of the removal of coal from the PJM capacity market, Black & Veatch assembled a typical Base Residual Auction Supply & Demand Curve as shown on Figure 7.
In this example, 5,000 MW of coal were removed from the supply stack at a zero price (with no replacement), which shifted the supply curve to the left and lifted the capacity prices by approximately 35 percent. It can also be observed from this graph that the addition of resources that have the ability to bid zero into the RPM market would have an effect in the other direction. The addition of resources such as wind, solar, demand response and energy efficiency will shift the supply curve to the right and lower capacity prices.

While the absolute removal of coal with no additional resources, or the addition of unconventional resources in isolation can have notable impacts on the RPM market, lately this has not been the case. In the latest auction (2015/2016), additional combined cycle and gas turbines were bid into and cleared the market. Figure 8 shows an example of the removal of 5,000 MW of coal, as in the previous example, but with the addition of some combined cycle and combustion bids placed into the market. The supply curve with the removal of coal follows the same trajectory as the previous example but starts to shift as new conventional resources are bid into the market at levels consistent with the Minimum Offer Price Rule (MOPR) in the PJM RPM. In this example, 8,000 MW were added to the system at prices between 70 dollars per kilowatt-year ($/kW-yr) and 100 $/kW-yr. Due to the difference in MW added to the supply curve, the new supply curve shifted to the right of the original curve, and prices were lower.
The amount of coal that is removed from the market will also have an effect on the energy market. Recent history has shown a decline in coal generation because of lower natural gas prices. In addition to current EPA regulation, these low prices are contributing to some of the decisions for coal plants to be idled or retired. With the retirement of coal generation, the natural replacement for this coal generation is combined cycle generation, given its efficiency and low capital costs. The effect of replacing coal with natural gas, over time, should naturally drive gas demand higher, and subsequently the price of natural gas. The resulting increase in natural gas prices should drive energy prices higher, and given the same level of capital costs, could lower the capacity clearing price as generators recover more of their revenue requirement in the energy market.

CONCLUSIONS

The examples listed herein for capacity are representative of how capacity additions and removals can affect the clearing price. The impact of these capacity changes can differ in different areas of PJM. In terms of capacity, resources located in certain areas of PJM may not be able to count toward reserve requirements in other areas. This causes the prices within PJM to separate into “pockets.” There are many other administrative rules in place that can affect the clearing price for capacity, such as the MOPR, transmission limit capabilities and how capacity cleared in a constrained area is transferred to another area within PJM. Each of these factors can have different effects on the capacity clearing price. When new capacity is added to replace the retired capacity, the new generating resources are most likely to be very efficient natural gas-fired resources like 2-on-1 combined cycles. As a result, energy prices will be more dependent upon natural gas prices moving forward. Should natural gas prices rise and increase the energy margin realized by efficient combined cycles and combustion turbines, the amount that a new generator can bid into the capacity market as a new entrant will be affected because...
of market rules. In this case, plant efficiency will become important because new generation will want to capture as much revenue from the energy market versus being subject to the constant changes in the capacity market.