THE FUTURE OF COAL VERSUS GAS COMPETITION

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Low natural gas prices were primarily responsible for the decimation of large segments of the US coal producing sector and the resulting decline in coal consumption.

In response to the decline in natural gas prices, the rail industry largely failed to reduce its rates. Therefore, in the next few years when increased natural gas prices cause gas- and coal-fired generators to compete for market share, more flexible railroad contracting could affect coal volumes.

An increase in natural gas prices from the recent range of $2.00–$3.00/MMBtu to $4.00 will produce a substantial increase in coal burned for power generation, which will offer a hard choice for producers as existing coal contracts expire and existing contracts approach price reopeners.

How upwardly price responsive can producers be while still maintaining tonnage given the economics of many coal-fired assets? Will efficient combined cycle facilities remain in relatively close competition at this natural gas price point? And, given that railroads have been reticent to reduce rail rates over the past few years what will happen if this low natural gas price environment continues?
2.0 Issue

This report explores the topic of how an increase in natural gas prices from the recent range of $2.00–$3.00/MMBtu to $4.00 will affect coal burn for power generation. Discussions will center on questions such as: what would the potential impact of an increase be on coal prices? Is an increase in coal consumption and prices even possible given how many coal-fired plants have closed since 2011? How have coal buyers hedged against this risk? How would coal producers and power generators, including those with nuclear power, be potentially affected?

Coal use for electric power production fell from 1,042 million tons in 2008 to 740 million tons in 2015. Two forces have been at work: prices for natural gas low enough to make gas-fired power generation competitive with coal; and tightened air emission and other environmental regulations on coal burning. These forces are additive so that when owners of coal-fired plants face gas competition and must invest to comply with environmental regulations, coal units are likely to lose. Since 2008, 46,000 MW of coal-fired generating capacity has been retired, which reflects about 15% of the 2008 total coal-fired MWh generating capacity. While many coal plants remain in operation, most are running at levels far below their potential.

This report explores the reasons for the reduction in coal use and the implications for coal buyers and sellers of an increase in prices of natural gas.
3.0 Power Market Background: Coal and Gas Competition in the Electric Power Market

Existing coal- and gas-fired power plants are continually competing against each other (both hourly and daily) in the markets for electric power.

For many power producers, they compete in regional markets where producers continually submit bids and the prices are set hourly. In others, the competition is led by the internal decisions of regulated electric utilities to minimize the hourly changes in power generating costs. The mix of generating capacity varies between regions, daily power demands and by season. But in every region, there are times at which either a coal-fired or a gas-fired plant could be called upon to meet a power demand. The decisions to operate these generating plants and the resulting output are based primarily on short run fuel cost and efficiency with some consideration for ramping times, minimum down times, etc. Non-fuel variable operating costs such as for pollution control chemicals are generally a minor component of costs. Therefore, as competitive fuel prices change, plant operations change.

At present, the cost of power generation for coal- and gas-fired plants is similar. A simplified example is presented in Exhibit 1.

In this example, as was frequently the case during 2016, the gas-fired plant would be operated in preference to the coal plant. However, an increase in the delivered gas price of $0.75/MMBtu would make the gas plant costlier and reverse the decision. As will be discussed later, the actual operational decisions are more complex, given varying daily demands for power and physical constraints on the flexibility of operation of plants and the entire electric system.

<table>
<thead>
<tr>
<th></th>
<th>Coal - Illinois Basin with SO₂ Removal</th>
<th>Gas Combined Cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delivered Cost of Fuel ($/MMBtu)</td>
<td>2.54</td>
<td>3.25</td>
</tr>
<tr>
<td>Fuel use per MWh, “heat rate” (MMBtu/MWh)</td>
<td>10.5</td>
<td>7.0</td>
</tr>
<tr>
<td>Fuel cost per MWh ($/MWh)</td>
<td>27.0</td>
<td>23.0</td>
</tr>
<tr>
<td>Non-Fuel Variable O&amp;M ($/MWh)</td>
<td>3.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Total Variable Cost ($/MWh)</td>
<td>30.0</td>
<td>25.0</td>
</tr>
</tbody>
</table>

Exhibit 1 – Coal vs. Gas Generating Cost Comparison, Southeastern US Fall 2016
The effect of the competition is that overall utilization of coal-fired plants is strongly related to the relative prices of coal and gas; and each plant’s operation depends on its fuel cost and efficiency. Frequently low- to mid-cost coal plants produce much more power than high-cost plants. For example, compare the operation of the Morgantown Generating Station in southern Maryland and the Herbert A. Wagner Generating Station in Baltimore Harbor. Both plants sell into the same PJM electric power market, but the Wagner plant has much higher operating costs. As shown in Exhibit 2, Wagner, the higher cost plant, operates at a much lower output level than Morgantown (measured by “capacity factor”—the ratio of actual to potential power generation).

The operation of both plants is quite volatile because of seasonal variations in power demand and continual changes in fuel market prices. Wagner’s operating costs are so high that during 2015 and 2016, it operated only during the periods of highest demand for power, such as the weekday afternoons. Since the minimum operating level of the plant is around 30% of rated capacity, a 10% monthly capacity factor implies that Wagner was only on about one-third of the month.

During periods of low power demand, generators with low variable operating costs, including nuclear and renewable energy plants, may be able to supply all the needed power so that neither coal- nor gas-fired power sets the market price. Generally, when gas prices are low, gas-fired plants operate and set the power price. However, in some regions, such as the Central US, there is so little gas-fired generation capacity that coal plants must operate even when gas prices are low. For these reasons, the relationship between the output of coal-fired plants and gas prices is complex and varies regionally. In this report the data is presented for the regions depicted in Exhibit 3 (SPP and MISO are combined in this report for some comparisons).
Exhibit 2 – Coal Capacity Factor Examples

Exhibit 3 – Map of Covered Regions

Source: PA Consulting Group and Energy Velocity
Some regional power organizations provide data that shows the percentage of time that coal, gas, or other fuels “are on the margin.” They indicate which fuel sets the market price for each hour. Exhibit 4 provides this information for 2010 and 2015 for three regions. During 2010, the average natural gas price was $4.39/MMBtu and during 2015 it was $2.63/MMBtu. As the price of natural gas declined, the percentage of hours during which gas was at the margin increased. Under these conditions, power prices fell and coal plant utilization declined.

Exhibit 4 – Regional Fuel on the Margin Summary.
Share of Hours on the Margin by Fuel Type Selected Regions 2010 vs. 2015

1. Annual average price at Henry Hub from US Energy Information Agency data.
These illustrations show that coal and gas are very competitive over this range of gas prices. At much higher gas prices, such as $8.83/MMBtu during 2008, coal plants were always cheaper to operate than gas-fired plants.

In Exhibit 5 the capacity factors of coal-fired plants in various regions since 2008 are shown along with the Henry Hub gas price (dashed line). The strong relationship is clear graphically, and supported by correlation coefficients of 79%–88% for all regions except WECC where the correlation is 69%. In WECC, coal plants have operated at relatively high capacity factors until gas prices declined well below $3/MMBtu.

Exhibit 5 shows that coal plants can operate at capacity factors of 70% and higher, as they did in 2008. As of 2015, the bulk of the coal-fired fleet was operating at around 50% capacity factor. Therefore, there is potential for these plants to burn around 50% more coal than they did in 2015. In addition to the decline in gas prices, increases in generation from wind and solar power have displaced some coal (and gas-fired) generation. The increase in renewable generation (including wind, solar and biomass) between 2008 and 2015 is responsible for about one-third of the decrease in coal generation over the same period. However, some of the wind and other power sources also displaced gas-fired power. Notably, over this period the total US production of electric power was essentially unchanged (a decline of 1%). Increased renewable generation displaced other sources of power making this a “zero sum game”.

The reduction in coal-based generation discussed above has two components: permanent closures of coal-fired plants and reduced operations at the remaining units. To a substantial extent, the remaining units fill in the power that was supplied by those shut down, so the effect of closures on coal demand is mitigated. The effect of the shut downs is explored in detail later in this report.

With regard to operations of the remaining plants, price competition between coal and gas, which determines the hourly cost of producing electric power, measured in $/MWh is critical. Hourly power markets are called “energy markets” and their profitability is a major determinant of the profitability of coal-fired plants. In several important regional markets (e.g. PJM and MISO) an explicit payment is also made to plant owners for “capacity” based on the rated MW plant output. Capacity contributes to the installed generating megawatts required to provide assurance of meeting peak-hour power demand. The determination of capacity payments in these regional market institutions is highly complex and can be controversial. Clearly, the thousands of megawatts of coal capacity that have been shuttered since 2008 indicate that the capacity payments alone are not nearly sufficient to keep all the plants in business.

Exhibit 5 – Coal Capacity Factor (%) vs. Henry Hub Price

4.0 Historical Changes in Power Generation and Coal Production

Exhibit 6 - Power Generated by Coal-Fired Plants (GWh) and % Change from 2008 to 2016

4.1 Power production and prices

In years of lower gas prices, generation has shifted rapidly between coal- and gas-fired units, resulting in reduced coal production and lower coal prices. Except for Northern, Central, and Southern Appalachian coal (a portion of which are also exported and/or used in steel making), electric power generators currently consume almost all US coal production. The export portion of Central Appalachian coal production, and the production of coal that can cross over into the metallurgical coal market, have been greatly affected by the collapse of international coal prices since 2011.

The percentage changes in generation from coal-fired plants between 2008 and 2015 are illustrated in Exhibit 6. While gas-fired power generation increased as coal power decreased, the accounts don’t balance. About two-thirds of the decline in coal power output from 2008 to 2015 was shifted to gas-fired plants. The remaining one-third of the decline in coal-fired generation was made up for by increased renewable energy production, of which the great majority was wind energy.

During this period, total US power production declined slightly (0.8%).

Exhibit 6 also includes an estimate of 2016 annual power generation based on data from January to July of 2016.

Among these regions there are striking differences in the extent of decline in coal-fired generation. The least affected region is ERCOT, where the delivered price of PRB coal remained competitive with gas at some plants until 2015. In the West, most of the coal burning plants are in areas where there is little gas-fired generation so the coal units must be operated, and many of these coal plants have delivered low fuel costs. In MISO, coal also dominates the available capacity. In the SPP area there is more opportunity for coal-gas competition. In both PJM and the South areas, where coal generation declined sharply, delivered coal prices are relatively high and there is plentiful gas-fired capacity. In ISO NE and NYISO (the northeast), delivered coal prices are high, and a great many of the coal plants are old, inefficient and have been closed since 2008.
4.2 Plant closures and their effects

A portion of the reduction in coal consumption is because of the closure of coal-fired plants. The extent of this effect has become important politically. In this analysis, we focus on the question of the long-term effect of the plant closures on coal consumption. Coal-fired capacity has been reduced because of the interacting combination of coal/gas competition, investments needed for environmental compliance, and normal maintenance of older plants. Had gas prices been higher, the investment needed to maintain these plants might have been justified. Had pollution control requirements been less stringent, some plants would have limped along even with low operating profits.

The plants that were closed were mostly those with relatively high fuel and other operating costs, so that in regions with many coal plants, they were operated the least. In 2008, the retiring plants (all three groups) aggregated to 19% of 2008 capacity in GW but 16% of 2008 power generation. The remaining coal plants therefore picked up some of the needed power output, and the other was taken up by gas or renewable capacity. Exhibit 7 shows the generating capacity in GW of the units already retired, planned for retirement, and remaining according to the coal supply region that is the major source for each plant.

Exhibit 8 shows a calculation to determine the effect of the closures on coal generation. In this comparison, the 2008 power generation at plants in all three groups of retired plants (A, B, C in Exhibit 7 above) is totaled.

This calculation begins with the total coal generation in 2008, compared to 2015, showing the reduction in production of 556,221 GWh (about 32%). Most of this reduction (370,216 GWh) occurred at the plants in groups C and D that were still operating in 2015. Note that in 2015, a fraction of the plants in group B were still operating, but closed during 2016. The important finding is that only 186,005 GWh, or 11%, occurred at the plants that shut down. Even if all the closures are attributed to pollution control requirements, clearly the dominant factor in reduced coal consumption is natural gas prices.

The coal plant closures and their effects vary regionally. Exhibit 7 shows the extent of past and planned closures grouped according to the coal source region for each plant.

Plants that burn Central Appalachian coal in the Eastern US are among the oldest, least efficient and have the highest percentage of being closed than any other group. The least-affected group are the plants that burn PRB coal. This is because they are mostly newer and larger efficient plants and the cost of pollution control is lower for plants using low sulfur coal than for plant using other types.
### Exhibit 7 - Recent and Planned Coal Plant Closures by Coal Supply Region

<table>
<thead>
<tr>
<th>Retirement Date Group</th>
<th>CAPP</th>
<th>ILB</th>
<th>NAPP</th>
<th>Other</th>
<th>PRB</th>
<th>Rockies</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Retired 2008–2011</td>
<td>1.3</td>
<td>0.5</td>
<td>1.3</td>
<td>3.3</td>
<td>1.1</td>
<td>0.2</td>
</tr>
<tr>
<td>B. Retired 2012–mid 2016</td>
<td>14.8</td>
<td>3.9</td>
<td>6.7</td>
<td>3.7</td>
<td>10.0</td>
<td>2.3</td>
</tr>
<tr>
<td>C. Planned Retire 2016-2021</td>
<td>2.4</td>
<td>1.3</td>
<td>0.1</td>
<td>1.6</td>
<td>3.4</td>
<td>1.0</td>
</tr>
<tr>
<td>D. Planned Operate post 2021</td>
<td>42.3</td>
<td>30.3</td>
<td>38.1</td>
<td>27.3</td>
<td>96.7</td>
<td>9.7</td>
</tr>
<tr>
<td>Total MW</td>
<td>60.8</td>
<td>36.0</td>
<td>46.2</td>
<td>35.9</td>
<td>111.3</td>
<td>13.2</td>
</tr>
<tr>
<td>Closures % of Region Total</td>
<td>30</td>
<td>16</td>
<td>18</td>
<td>24</td>
<td>13</td>
<td>26</td>
</tr>
</tbody>
</table>

### Exhibit 8 - Analysis of Effect of Closures on Coal Generation Since 2008

<table>
<thead>
<tr>
<th>National Total Coal GWh</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008 Generation of Plants</td>
<td>18.112</td>
<td>201,907</td>
<td>51,217</td>
<td>1,440,726</td>
<td>1,711,962</td>
</tr>
<tr>
<td>2015 Generation of Plants</td>
<td>0</td>
<td>34,014</td>
<td>30,107</td>
<td>1,091,619</td>
<td>1,155,741</td>
</tr>
<tr>
<td>Change 2008–2015</td>
<td>(18,112)</td>
<td>(167,892)</td>
<td>(21,110)</td>
<td>(349,107)</td>
<td>(556,221)</td>
</tr>
<tr>
<td>Net Loss from Shutdowns</td>
<td>(186,005)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Loss from Shutdowns as % of 2008 GWh</td>
<td>-11</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Exhibit 9 shows how the loss in coal generation from 2008 to 2015 was divided among coal supply regions.

While the reduction in output in aggregate GWh was largest for plants burning PRB coal, by far the most severe reduction as a percentage of 2008 generation was for plants burning Central Appalachian coal, whose output fell by almost half. Plants burning Illinois Basin coal were the least affected, with output falling by about a quarter during this period. Delivered prices of Illinois Basin coal are generally low, so these plants are less vulnerable to competition with gas. Mostly coal is being burned in the central Midwest (IL, IN, OH, KY) as there is relatively little gas-fired generating capacity.

The biggest group of plant closures considered here is for the 2012–2016 period (70% of the total MW closed). Exhibit 10 shows the tonnage of coal burned in 2011 by the plants closed during 2012–2016, as a percentage of total steam coal production from each coal supply region during this period. Unsurprisingly, the largest percentage declines in steam coal deliveries were incurred by the coal types that have the highest delivered coal prices (CAPP and NAPP). While current market prices are the primary determinant of unit dispatch, the existence of legacy contracts at prices that differ from market. For example, the designation of some generating units as “must-run” to balance load also affect dispatch decisions for the affected units.
**Exhibit 9** – Power Output Reduction by Coal Source 2015 vs. 2008

<table>
<thead>
<tr>
<th>Coal supply region</th>
<th>2011 steam coal deliveries to plants retiring in 2012-2016 (million tons)</th>
<th>2011 steam coal production (million tons)</th>
<th>% of 2011 steam coal production delivered to retiring plants</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPP</td>
<td>17.5</td>
<td>123.4</td>
<td>14.2%</td>
</tr>
<tr>
<td>NAPP</td>
<td>11.1</td>
<td>117.3</td>
<td>9.5%</td>
</tr>
<tr>
<td>ILB</td>
<td>8.3</td>
<td>115.6</td>
<td>7.2%</td>
</tr>
<tr>
<td>PRB (Wyoming portion)</td>
<td>29.7</td>
<td>426.2</td>
<td>7.0%</td>
</tr>
<tr>
<td>Rockies</td>
<td>5.2</td>
<td>89.2</td>
<td>5.8%</td>
</tr>
</tbody>
</table>

Sources: Coal production figures are from EIA or MSHA, and are shown. Net of estimated metallurgical coal production of 60 million tons from CAPP and 15 million tons from NAPP. Coal deliveries are from Form EIA-923.

**Exhibit 10** – Coal deliveries to plants retiring in 2012-2016
5.0 Analysis of Future Market Response

5.1 Dispatch

5.1.1 Model Inputs and Results

The interactions between future market dynamics including expanded coal retirements, coal and gas prices, increased renewable energy, energy efficiency and a myriad of other market factors are complex. Therefore, historical relationships between coal demand and fuel prices may break down as the market goes through a high degree of structural change. Dispatch modeling using simulation tools provides a powerful approach for examining how these relationships may change under future market conditions. For this analysis, the AURORAXMP model was used to simulate market responses to changes in natural gas prices. AURORAXMP is a power market simulation tool based on an hourly dispatch engine that represents the hourly dispatch of power plants in a chronological, multi-zone, transmission-constrained system. AURORAXMP is widely used for electric-market price forecasting, resource valuation, and market risk analysis.

The AURORAXMP detailed technical inputs include commodity and emissions prices, generator dispatch characteristics, demand forecasts, and transmission topology while the model’s outputs include generator dispatch, fuel consumption, and power prices.

Key model input assumptions

The most important model inputs for this analysis are discussed below.

Natural Gas Prices

Increasingly, across many US power markets, natural gas prices influence power prices. Coal demand is particularly sensitive to the natural gas market. Since 2012, natural gas prices have been low enough to substantially effect coal consumption, and were especially low (See Exhibit 11) during 2015 and most of 2016, reaching as low as $1.71/MMBtu in March 2016. Since March 2016, prices have seen significant recovery, climbing to the $3.40/MMBtu level by December 2016.

For this analysis, PA’s November 30, 2016 gas forecast (See Exhibit 12) was used for the base case assumptions. As of November 30, 2016, the NYMEX Henry Hub forward curve showed natural gas prices of $3.29/MMBtu in 2017, and dropping $0.42/MMBtu by 2019. Then staying virtually flat on a nominal basis through 2021. Conversely, the PA forecast begins with the same prices for 2017, with prices easing somewhat for 2018, but then rising steadily to the ~$4.00/MMBtu level by 2021.

Exhibit 11 – Recent Henry Hub Spot Prices ($/MMBtu)
These rising gas prices in the PA forecast are heavily influenced by a set of demand factors which should place upward pressure on natural gas prices over the next 5 years. This includes increased gas demand from approved LNG projects, with the consensus view (shared by PA) that the US will export around 8 Bcf per day of LNG by 2020. In addition, there is a significant amount of new gas-fired combined cycle capacity coming online in the US over the next five years (with a significant amount of this capacity located in the heart of the Marcellus and Utica shale gas plays). Additionally, industrial demand, which was just under 21 Bcf per day in 2015, is projected to grow by an incremental 3 Bcf per day by 2020, driven by demand from fertilizer/ammonia projects and methanol plants. Natural gas demand will also see an extra push from increased exports to Mexico, which are expected to average 4.5 Bcf per day by 2020. Mexico is in the midst of a vast energy revolution. The Comisión Federal de Electridad is leading an effort to convert existing oil-fired power plants to natural gas, as well as proposing new natural gas-fired facilities with a total capacity of nearly 37 GW by 2035. The combined effect of these factors is an expected ~15.5 Bcf per day of incremental gas demand by 2020, which should place upward pressure on natural gas prices over the next three to five years.

**Coal Prices**

For this analysis, coal prices were held constant under each modeling case, and based on the PA November 30, 2016 coal forecast. The PA coal forecast is unique to each coal generating unit in North America, with prices comprised of a commodity price (FOB price) and a transportation charge developed by Hellerworx. Commodity costs are based on a forecast of various coal specs across US basins as well imported coal, and are influenced by coal-forward market prices, as well as, supply/demand dynamics. Transportation costs for each unit change over time, with different escalation rates for each mode of transportation (rail, barge, etc.), and are influenced by projected changes in diesel, labor and materials costs.

**Exhibit 13** shows the representative FOB and delivered coal costs for major coal basins, from the PA November 30, 2016 coal forecast. The forecast reflects recent upward movements in coal pricing for 2017, as coal prices have already shown some near-term recovery from the lows of spring 2016, following the upward trend in natural gas prices.

**Coal Generating Plant Retirements**

Since 2012, the US has seen a swath of coal power plant retirements. This was driven by a combination of low wholesale power prices, increased competition from gas-fired resources, the Mercury and Air Toxics rule (“MATS”), which required the installation of costly emissions control systems on many units by April 2015, and by April 2016 for units receiving a one-year compliance extension.

While retirements related to MATS are largely completed, over the next five years continued relatively low natural gas prices, additional environmental rules including the EPA Regional Haze, Coal Combustion Residuals (“CCR”), Effluents and Cooling Water Intake Structures (“316B”), may drive some further coal retirements. This may limit some of the upside in coal consumption in response to a natural gas price increase, and is therefore an important input into the simulation model. **Exhibit 14** (repeated here from **Exhibit 7** for ease of reference) shows a summary of recent coal plant retirements, as well as retirements planned through 2021.

Just over 40 GW of coal retirements were completed between 2012 and mid-2016, with roughly half of this coming from plants burning Appalachian coal, and roughly 25% comprised of PRB burners. Currently, an additional 10 GW of firm coal retirements are slated over the next five years.

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3. The values shown in Exhibit 14 are weighted averages. For PRB coal (which has the greatest range of transportation rates on a $/MMBtu basis), the forecast 2017 delivered coal prices for individual plants can range from a low of about $1.00 per MMBtu for a plant located in Nebraska (near the PRB coal field) to a high of about $3.00 per MMBtu for a plant located in Georgia. For the other basins, there would also be a range of delivered prices though somewhat narrower than for PRB coals.
**Exhibit 12** – PA Henry Hub Base Case Forecast, and Gas Price Sensitivities, vs. NYMEX Forward Curve

**Exhibit 13** – 2017 Coal Price Assumptions from PA November 30, 2016 Forecast (Nominal $/MMBtu)

<table>
<thead>
<tr>
<th>Retirement Date Group</th>
<th>CAPP</th>
<th>ILB</th>
<th>NAPP</th>
<th>Other</th>
<th>PRB</th>
<th>Rockies</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Retired 2008–2011</td>
<td>1.3</td>
<td>0.5</td>
<td>1.3</td>
<td>3.3</td>
<td>1.1</td>
<td>0.2</td>
<td>7.7</td>
</tr>
<tr>
<td>B. Retired 2012–mid 2016</td>
<td>14.8</td>
<td>3.9</td>
<td>6.7</td>
<td>3.7</td>
<td>10.0</td>
<td>2.3</td>
<td>41.4</td>
</tr>
<tr>
<td>C. Planned Retire 2016–2021</td>
<td>2.4</td>
<td>1.3</td>
<td>0.1</td>
<td>1.6</td>
<td>3.4</td>
<td>1.0</td>
<td>9.7</td>
</tr>
<tr>
<td>D. Planned Operate post 2021</td>
<td>42.3</td>
<td>30.3</td>
<td>38.1</td>
<td>27.3</td>
<td>96.7</td>
<td>9.7</td>
<td>244.4</td>
</tr>
<tr>
<td><strong>Total MW</strong></td>
<td>60.8</td>
<td>36.0</td>
<td>46.2</td>
<td>35.9</td>
<td>111.3</td>
<td>13.2</td>
<td>303.3</td>
</tr>
<tr>
<td><strong>Closures % of Region Total</strong></td>
<td>30</td>
<td>16</td>
<td>18</td>
<td>24</td>
<td>13</td>
<td>26</td>
<td>19</td>
</tr>
</tbody>
</table>

**Exhibit 14** – Coal Plant Retirements by Retirement Group and Coal Source Basin
New Gas Additions
While the relative price between coal and gas is a significant factor in coal-to-gas switching, switching is limited in regions without much installed gas capacity. Thus, future levels of regional gas generation shown in Exhibit 15 are an important input in determining a relationship between natural gas prices and coal burn.

In total, ~37 GW of new gas combined cycle capacity is slated to come online between 2016 and 2020, with the bulk of this capacity planned for regions where there is a large amount of installed coal capacity. Roughly half of this comes from the PJM region alone, where ~5 GW of new combined cycle capacity has cleared each of the last several forward capacity auctions, replacing nearly all of the ~20 GW of coal retirements seen in the market between 2012-2015. The South has seen substantial new combined cycle development, with ~7 GW expected online between 2016 and 2020, threatening to intensify coal-to-gas switching dynamics in the market over the next few years.

Exhibit 15 – Firm Gas Combined Cycle Additions 2016–2020
5.1.2 Model Approach and Results

AURORAXMP was used to simulate market results over the next several years under four scenarios based on differing natural gas prices. This includes a base case, with natural gas prices set based on PA’s base Henry Hub forecast of $3.29/MMBtu for 2017, and three additional cases with Henry Hub prices set at a nominal price of $2.50/MMBtu (“Low Gas Case”), $3.00/MMBtu (“Mid Gas Case”), and $4.00/MMBtu (“High Gas Case”). In each case, all model inputs were identical except for differing natural gas prices, in order to evaluate the independent impact on power prices and power-sector coal demand from a change in gas prices.

Coal Demand Impacts

Exhibit 16 shows incremental power sector coal burn under each of the three nominal gas cases considered. For each case, incremental coal demand is calculated as total coal burn in each basin under the respective gas case, less the coal demand for that basin from the PA base case.

These results show the substantial sensitivity of power sector coal demand to natural gas price swings at gas prices in the $2.50–$4.00 per MMBtu range. In particular, at current base case coal price levels for 2017, coal demand is particularly vulnerable to switching when gas price levels fall below $3.00/MMBtu. Conversely, at gas prices above $3.50/MMBtu, coal volumes begin to pick up substantially. A summary of results for each case for 2017 are outlined below.

---

Exhibit 16 – Incremental Coal Burn under Henry Hub Scenarios (millions of tons)
At current coal price levels, these results represent a possible swing of 314 million tons of power-sector coal burn across the full range of natural gas prices examined. However, it is important to point out that dispatch simulation models can overestimate potential fuel consumption movements, and thus these values should be thought of as maximum levels of potential switching. Dispatch models can overestimate switching levels due to several key factors including:

- Dispatch models have perfect foresight into commodity prices. Since in reality, coal must be purchased well ahead of the power dispatch decision, and before natural gas price levels are known, large instantaneous shifts in coal burn may not be possible given the risks associated with fuel procurement.
- The majority of coal is still procured through contract versus spot market purchases. Many of these contracts are structured as take-or-pay arrangements or require substantial liquidated damages for failure to take contract tonnages. As a result, coal burn levels tend to be “stickier” versus fuel price movements that would be simulated in a dispatch model. Among coal deliveries during the past 12 months, roughly 25% were procured under contracts with three or more years remaining on the contract, while an additional ~11% had contracts with two years remaining.
- Economic frictions and ownership issues may prevent some possible coal-to-gas switching from occurring. In a dispatch model, coal can potentially be displaced by a gas generator separated by several balancing authorities. While this is possible in reality, potential trading frictions associated with moving this power may make this difficult. Additionally, ownership differences between coal and gas plants outside of ISO markets may make it less likely all switching will be realized. As an example, in the Southeast, virtually all of the coal capacity is owned by vertically integrated utilities, while roughly half of the gas combined cycle capacity is merchant. Thus, to realize all potential switching, utilities may have to make arrangements with regional merchant generators that involve trading frictions, and making it unpalatable for utilities to choose not to run owned-assets in lieu of merchant plants for long periods of time.

- $2.50 Henry Hub – At these gas prices, which are $0.80/MMBtu below the PA base case forecast for 2017, coal volumes across all basins drop by 185 million tons, or 21% of 2015 basin production. PRB coal would see the largest decline absorbing 99 million tons of lost tonnage, or 24% of 2015 production, while the Appalachian and Illinois basins could see volume declines reaching 14-17% of 2015 production. Gas demand would increase by 7.0 Bcf/day.

- $3.00 Henry Hub – At $0.30/MMBtu below the PA base case forecast for 2017, coal volumes across all basins drop 69 million tons compared to base case levels, or 8% of 2015 coal production. PRB coal would again see the largest decline losing 38 million tons, or 9% of 2015 production, while the Appalachian and Illinois basins could see volume losses comprising 5-7% of 2015 volumes. Gas demand would increase by 2.58 Bcf/day.

- $4.00 Henry Hub – Gas prices in this case represent a -$0.70/MMBtu upside to PA’s base case forecast for 2017, but within the range of outcomes that might be seen by 2021. At gas price levels in this range, coal volumes could see a -129 million ton uptick versus base case levels, with PRB again comprising the lion’s share of swing volumes, with an incremental 68 million tons of demand. Central and Northern Appalachian basins could also see a combined incremental 27 million tons of coal burn as a number of Mid-Atlantic coal units become competitive versus regional gas plants. With Henry Hub prices in 2017 of $4.00 the total estimated coal consumption would be about 790 million tons, compared to 1,046 million tons in 2008. In 2008, the plants that have since been retired burned approximately 100 million tons, at a gas price of almost $9/MMBtu.

- Two conclusions emerge: a $4.00 gas price is not nearly high enough to restore coal consumption to peak historical levels, and neither would the restoration of the retired plants. Note that at a gas price of $4.00 the old high-cost retired plants would burn much less than the 100 million tons they consumed in 2008.
Power Price Impacts

AURORAXMP was utilized to examine incremental impacts on regional wholesale power prices in 2017 resulting from movements in natural gas prices. As was done for the analysis of coal burn, all variables, including coal prices, were held constant with only natural gas prices changed between each case.

Exhibit 17 shows the impact on regional around-the-clock (ATC) wholesale power prices under each Henry Hub price case relative to PA’s Base Case forecast.

Exhibit 17 indicates a varying degree of impact to wholesale energy prices across the gas scenarios evaluated. The WECC region, which includes all of the US Western Interconnect, shows the most sensitivity of average power prices to changes in gas prices, with prices falling $4.56/MWh in the low gas scenario relative to power prices under the PA base case, and rising $4.56/MWh in the high gas scenario.

Other large impacts to wholesale energy prices would occur in the South and ERCOT regions, where ATC power prices were found to fall by over $4.00/MWh relative to the base case in each of these regions under the low gas case, with prices rising over $3.50/MWh in the scenario where Henry Hub prices rise to $4.00/MWh. Prices in the ERCOT market have historically been heavily influenced by natural gas, with a rash of recent coal retirements and conversion of many coal units to natural gas, coupled with continued regional combined cycle development, making the South region sensitive to gas price swings.

<table>
<thead>
<tr>
<th>Case</th>
<th>ERCOT</th>
<th>MISO/SPP</th>
<th>PJM</th>
<th>SOUTH</th>
<th>WECC</th>
<th>ISO-NE/NYISO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Gas Case</td>
<td>-4.27</td>
<td>-3.50</td>
<td>-3.80</td>
<td>-4.36</td>
<td>-4.56</td>
<td>-5.45</td>
</tr>
<tr>
<td>Mid Gas Case</td>
<td>-1.48</td>
<td>-1.27</td>
<td>-1.40</td>
<td>-1.59</td>
<td>-1.73</td>
<td>-2.04</td>
</tr>
<tr>
<td>High Gas Case</td>
<td>3.64</td>
<td>2.95</td>
<td>3.13</td>
<td>3.82</td>
<td>4.32</td>
<td>4.81</td>
</tr>
</tbody>
</table>

Exhibit 17 – Impact to ATC Wholesale Power Prices under Gas Cases ($/MWh)
5.2 Coal Prices and Production

Production by supply region
Not all regions have been equally affected by the decline in coal production. Exhibit 18 shows the trends in coal production for some of the most important regions.

Central and Southern Appalachia producers have seen the most severe reductions. In addition to reductions in shipments to power producers, mines in this region also produce coking and steam coal for export. After an exceptionally high year in 2008, US exports have sharply fallen. Illinois Basin coal production, unlike in every other region, has increased over the period. This has occurred as SO2 control systems were installed at many plants, making it possible for them to shift from more-expensive low sulfur coal (primarily sourced from Central Appalachia and/or the Powder River Basin) to the cheaper Illinois Basin high sulfur coal.

Coal prices by supply region
As coal consumption has fallen so, at least until very recently, have prices. Exhibit 19 shows spot coal prices for three important coal types from 2008 to late 2016. The results have been severe. Several of the largest publicly-traded coal producers have gone through bankruptcy since 2008 including Peabody, Arch, Alpha Natural Resources, Walter Energy, Patriot, and James River. Despite these harsh conditions, the extent of permanent closure of mines during this period has been modest. The exception is Central Appalachia, where many mines are relatively small and the turnover rate is substantial. Given some time, production can recover in the PRB and Northern Appalachia and resume its growth in the Illinois Basin.

For 2008–2015, the prices shown in Exhibit 19 are annual averages. For 2016, the prices for January and November are shown because prices changed so rapidly during the year. The data shows that coal prices are volatile. From 2011 to 2012, Central Appalachian production fell by 18% and the price of a representative coal product declined by a similar percentage (19%) from $2.98 to $2.42/MMBtu. Considering this data, as well as rapid price increases during 2007–2008, and very recently a sharp increase in coal prices following, a substantial increase in coal demand is predictable.

It is not the purpose of this report to discuss in detail the history of coal markets over this period, but rather to examine the tie between gas and coal. However, the price history shown in Exhibit 19 also reflects other events. Economies around the world went into recession during 2008 and almost all world commodity prices fell. Central Appalachian coal, for which foreign demand was high during 2008, was strongly affected. Similarly, recent increases in world market prices resulting from actions of the Chinese government among other forces, have caused a sharp increase in world coal prices, and consequently Appalachian coal prices. PRB and Illinois Basin coals are not sold in large quantities in the world market. All three of these regions did go through a classic boom-and-bust commodity cycle; with rising prices triggering capacity expansion and then collapse. Note that as shown in Exhibit 6, coal power generation declined in some regions from 2008 to 2009. Interestingly gas power generation barely changed, even though gas prices fell 50%. The reduction in coal use in 2009 was largely because of the fall in total national demand for power. As the economy recovered in 2011, so did coal prices, assisted by an increase in world market prices resulting from a combination of continued high imports by China and weather-related disruptions of production in Australia.

4. Note that, although Powder River Basin coal can be mined relatively cheaply, the heat content of this coal is relatively low, and therefore the cost of transporting this coal long distances can be quite substantial on a $/MMBtu basis. Therefore, Illinois Basin coal may be cheaper than Powder River Basin coal on a delivered $/MMBtu basis for some coal-fired generating plants located in the Midwestern or Eastern United States.
Exhibit 18 – Regional Coal Production

Exhibit 19 – Coal Price Series PRB, ILB, CAPP
2012 was the first year in which low gas prices became the main driver of coal demand. Natural gas prices at Henry Hub averaged $2.75 for the year, down from $4.00 in 2011. To compare gas and coal prices for power generation it is necessary to account for the much higher efficiency of gas turbine combined cycle (GTCC) power plants compared to coal-fired plants. Typically, about 7 MMBtu of gas are required per MWh produced at GTCC plants. Coal power plants typically require 10–10.5 MMBtu/MWh (see Exhibit 1 for example). Power produced using natural gas at $2.75–$3.50/MMBtu at GTCC plants can compete with coal power in many regions. As shown earlier in Exhibit 5, the effect of the lower gas prices in 2012 was to substantially reduce coal power output. Coal prices consequently dropped sharply. With a rebound in gas prices, the coal prices stabilized until the spring of 2016 when gas prices fell as low as $1.73/MMBtu.

Starting in the late summer and early fall of 2016, a large and unexpected increase in world coal market prices occurred. The primary driver of this increase was the efforts of the Chinese government to reduce surplus coal production in China—and they appear to have overshot the objective dramatically. Prices of coal used for steelmaking more than doubled over a few months. US prices, especially for exportable Appalachian coals, have risen with the world market. The market perception of this event is reflected in current coal futures market prices which are exceptionally “backwardated” and future prices are substantially below price for immediate delivery. PA believes that the market perception is accurate and the current price level is not likely to be sustained.

The reduction in coal power generation with falling gas prices indicates that the fall in coal prices was not enough to restore the competitive position of coal. That is very much the case. First, the magnitude of the changes in coal prices at the mine is small in relation to the changes in gas prices. For example, the Henry Hub gas price fell from $2.28/MMBtu in January 2016 to $1.73/MMBtu in March 2016, a drop of $0.55/MMBtu. During the same period the mine price of CAPP coal fell by only about $0.03/MMBtu. The lower downward volatility of coal prices is limited by the large number of mines barely covering variable costs of production at the early-2015 price level. While short-term variable costs of natural gas production are a much smaller share of price at many gas and oil wells.

Second, for most power plants in areas outside the Ohio River valley, rail transportation costs are a large portion of the delivered prices. As will be discussed later, railroads mostly chose not to reduce prices as gas prices fell and coal consumption dropped, preferring a higher margin on lower tonnage. These phenomena are illustrated in Exhibit 21, which is a rough estimate of the cost of coal vs. gas power generation at a Florida power plant (TECO’s Big Bend plant, near Tampa), assuming spot market prices for both fuels. In this exhibit, the coal plant is assumed to have a typical heat rate for dispatch (short term operation decisions) of 10.5 MMBtu/MWh and 7 MMBtu/MWh is assumed for the competing GTCC plant. The periods shown on this exhibit during which gas power would have been cheaper than coal correspond well to the pattern of variation in coal-fired generation shown earlier in Exhibit 5.

5. The Central and Northern Appalachian coal fields are the US coal fields located closest to Europe, which has historically been a major market for US exports of either steam coal used in power generation, or metallurgical coal used in steelmaking. Additionally, some Central Appalachian and Northern Appalachian coals can be marketed as either steam or metallurgical coals, and reserves of metallurgical coal are scarcer globally than reserves of steam coal. Finally, the currently available routes to export either PRB or Illinois Basin coal to the Asian market (which is likely to be the largest future market for steam coal exports from the US) are relatively long and involve relatively high transportation costs within the Continental US. For all of these reasons, Appalachian coal prices are more responsive than prices for PRB or Illinois Basin coal to movements in international coal prices.

6. The prices are only estimates because the reported coal delivery data do not always include spot purchases for each period and because gas transportation costs for particular plants and as used for economic dispatch of plants are not well reported.
Exhibit 20 – Quality Specifications for Example Coal Types

<table>
<thead>
<tr>
<th>Coal Basin</th>
<th>Btu/lb.</th>
<th>Lbs. SO₂/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Appalachia (CSX)</td>
<td>12,500</td>
<td>1.5-1.6</td>
</tr>
<tr>
<td>Illinois Basin</td>
<td>11,800</td>
<td>4.5</td>
</tr>
<tr>
<td>Powder River Basin</td>
<td>8,800</td>
<td>0.8</td>
</tr>
</tbody>
</table>

Exhibit 21 – Power Production Cost Coal vs. Gas in Florida
5.3 Railroad Response to Declining Production

The railroad response to the severe decline in coal production and consumption during the 2008–2016 time period has been surprising and instructive. There are four major railroads who originate US coal, Burlington Northern Santa Fe (“BNSF”) and Union Pacific (“UP”) in the West, and CSX Transportation (“CSX”) and Norfolk Southern (“NS”) in the East and Midwest. Shortlines and the other Class I’s handle US coals as well, but these four are the primary carriers.

In the West, UP and BNSF both originate Powder River Basin coals. Most of these coals move long distances at rates which are high relative to the cost of the coals. While mine prices may range from $8–$12/ton, the rail rates can easily run $25–30/ton for movements to the Southwest and Midwest. As such, the railroads are responsible for more of the delivered coal costs than the coal producers. While coal prices from the PRB declined substantially, the railroads response was minimal. BNSF offered some spot pricing into Texas that was tied to gas prices, but rail rates stayed largely static. The railroads chose to accept major declines in coal tonnage shipped rather than make major reductions in rates. See Exhibits 22 and 23 which show the change in coal volumes for the western carriers and change in average rail rates.

In the East, the effects were similar. Neither CSX nor NS seems to have attempted to compete with natural gas-fired generation on a large scale anywhere in the Eastern United States. Both CSX and NS instead appeared to have accepted large losses in coal volume (totaling about 50% between 2008 and 2016, including a 25% decline during the past two years alone) rather than making major reductions in rail rates. While the carriers probably could not have reduced rates sufficiently to avoid some losses of coal volume to cheap natural gas, their failure to respond seemed to indicate a desire to maintain their rate structures in the belief that when gas prices strengthened, they would be able to achieve higher revenues on the remaining reduced volume levels.

During part of this period, increases in crude-by-rail shipments and associated products for oil and gas drilling provided attractive growth markets. However, these did not come close to offsetting the coal volume losses.

Export coals were treated differently by the carriers than domestic coals, and coking coals were treated differently than thermal coals. Export coking coals are shipped by the Eastern carriers and some of these coals have unique and valuable characteristics in the global markets. The carriers did reduce tariff rates as export markets declined during this period. The most dramatic response was related to thermal coals. The carriers reduced rates by almost 50% as thermal export markets collapsed in an attempt to maintain the Central Appalachian mines that had no other outlets for their production. By 2015, export rates for thermal coals were between $15–20/ton down from $30–35/ton. Coking coal rates for virtually identical movements were in the $40–50/ton range.

Western coal exports of PRB coal was a burgeoning business in 2008. No US coal ports had been built to handle PRB coal, so it was mostly shipped through Vancouver ports. In 2014, Cloud Peak indicated that it was going to pay contractual liquidated damages to BNSF and Westshore terminals for its failure to meet minimum volume commitments rather than make shipments at the prevailing depressed market prices. In late 2016, Cloud Peak resumed shipments when markets improved.
Market Impacts on Rail Producers
While this report is not focused on the coal production sector per se, it is important to note what the impact of reductions in coal demand and coal prices have been on the US coal producing industry. Since April 2015, a huge portion of the US coal industry, including the largest publicly traded companies, have declared bankruptcy. This includes:

- Peabody Energy April 2016
- Arch Coal January 2016
- Alpha Natural Resources August 2015
- Patriot Coal Corp. May 2015
- Xinergy Corp. April 2015

Many mining operations have been closed by operators that did not go into bankruptcy. In addition, many smaller operations have ceased production or gone out of business. The net effect is a US coal production sector with significantly less capacity than it had three years ago, and likely less ability to rapidly respond to market demand fluctuations.

In contrast to the rail industry which failed to reduce rates significantly in response to competition from natural gas-fired generators, the coal industry commodity prices and volumes declined so sharply that bankruptcies and mine closures became pervasive.

<table>
<thead>
<tr>
<th>Railroad</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>1Q-3Q 2016</th>
<th>Annualized 2016</th>
<th>Change in total Tonnage '08–'14</th>
<th>Change in total Tonnage '14–'16</th>
<th>Change in total Tonnage '08–'16</th>
<th>Annualized % Change 2008-2014</th>
<th>Annualized % Change 2014-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSX MM tons</td>
<td>196</td>
<td>172</td>
<td>174</td>
<td>171</td>
<td>145</td>
<td>134</td>
<td>143</td>
<td>121</td>
<td>70</td>
<td>93</td>
<td>(53)</td>
<td>(50)</td>
<td>(103)</td>
<td>-5.1</td>
<td>-19.5</td>
</tr>
<tr>
<td>NS MM tons</td>
<td>194</td>
<td>158</td>
<td>171</td>
<td>178</td>
<td>156</td>
<td>150</td>
<td>142</td>
<td>120</td>
<td>73</td>
<td>98</td>
<td>(52)</td>
<td>(44)</td>
<td>(97)</td>
<td>-5.1</td>
<td>-17.0</td>
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<tr>
<td>UP MM tons</td>
<td>270</td>
<td>233</td>
<td>238</td>
<td>251</td>
<td>217</td>
<td>205</td>
<td>168</td>
<td>99</td>
<td>132</td>
<td>(65)</td>
<td>(73)</td>
<td>(138)</td>
<td>-4.5</td>
<td>-19.7</td>
<td></td>
</tr>
<tr>
<td>BNSF '000 carloads</td>
<td>2,516</td>
<td>2,390</td>
<td>2,415</td>
<td>2,309</td>
<td>2,172</td>
<td>2,230</td>
<td>2,270</td>
<td>2,286</td>
<td>1,279</td>
<td>1,705</td>
<td></td>
<td></td>
<td>-1.7</td>
<td>-13.3</td>
<td></td>
</tr>
</tbody>
</table>

Exhibit 22 – Coal Traffic Volumes for the Largest Coal-Hauling Railroads in the United States
(millions of short tons, except BNSF which is in thousands of carloads)
Source: Company financial reports.

<table>
<thead>
<tr>
<th>Railroad</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>1Q-3Q 2016</th>
<th>Annualized 2016</th>
<th>Change in total Tonnage '08–'14</th>
<th>Change in total Tonnage '14–'16</th>
<th>Change in total Tonnage '08–'16</th>
<th>Annualized % Change 2008-2014</th>
<th>Annualized % Change 2014-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSX</td>
<td>36.7</td>
<td>36.3</td>
<td>41.1</td>
<td>48.5</td>
<td>47.5</td>
<td>44.9</td>
<td>41.0</td>
<td>40.9</td>
<td>37.9</td>
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<td></td>
<td></td>
<td>-3.8</td>
<td></td>
</tr>
<tr>
<td>NS</td>
<td>50.1</td>
<td>46.3</td>
<td>52.0</td>
<td>61.1</td>
<td>59.7</td>
<td>53.6</td>
<td>50.8</td>
<td>46.2</td>
<td>44.6</td>
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<td>-6.3</td>
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<tr>
<td>UP</td>
<td>14.7</td>
<td>14.3</td>
<td>15.5</td>
<td>17.1</td>
<td>18.9</td>
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<td>-1.7</td>
<td></td>
<td></td>
<td>-1.7</td>
<td></td>
</tr>
<tr>
<td>BNSF</td>
<td>13.0</td>
<td>13.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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</tbody>
</table>

Exhibit 23 – Average Coal Rates (per ton-mile) for the Largest Coal-Hauling Railroads in the United States
(Millions per ton-mile; one million = 1/10cent)
Source: Company financial reports.
Note: BNSF stopped reporting its rates on a per ton-mile basis after being acquired by Berkshire Hathaway (effective February 12, 2010.)
6.0 Implications and Conclusions

The decline in coal consumption due to low natural gas prices was primarily responsible for decimating large segments of the US coal producing sector.

The rail industry largely failed to reduce rates in response to the decline in natural gas prices. In the next few years when increased natural gas prices cause gas- and coal-fired generators to compete for market share, more flexible railroad contracting could affect coal volumes.

An increase in natural gas prices from the recent range of $2.00–$3.00/MMBtu to $4.00 will produce a substantial increase in coal burned for power generation. It will offer a hard choice for producers as existing coal contracts expire or existing contracts approach price reopeners. Certainly, higher demand should translate to upward price response among coal producers; however, any such upward movement in coal commodity prices may need to be tempered absent railroads capitulating on current transport rate levels given the economics of many coal-fired assets with efficient combined cycle facilities will still be in relatively close competition at this natural gas price point.
As energy markets continue to evolve around the world, liberalizing in countries and sectors previously closed, reforming and evolving in many places that were previously liberalized, there is work to be done to capitalize on the global trends in energy investment. The opportunities for investment are plenty but so are the pitfalls.

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