May 2009

Short-Term Energy Outlook Supplement:

The Implications of Lower Natural Gas Prices for the Electric Generation Mix in the Southeast[1]

Highlights

- This supplement to the Energy Information Administration's (EIA) May 2009 *Short-Term Energy Outlook* (*STEO*) focuses on changes in the utilization of coal- and natural-gas-fired generation capacity in the electric utility sector as the differential between delivered fuel prices narrows.

- Over the last year the price of natural gas delivered to electric generators has fallen dramatically. Current natural gas prices now present increased potential for displacing coal-fired electricity generation with natural-gas-fired generation.

- Because combined cycle natural-gas-fired electricity generators are generally more efficient than typical coal-fired units, consuming fewer Btu of fuel per kilowatthour of electricity generated, natural gas prices do not need to fall as low as coal prices before substitution of natural gas becomes attractive.

- The delivered cost of coal is generally highest in the southeast region of the United States because of transportation costs from the coal-producing regions such as the Powder River Basin in Montana and Wyoming. Consequently, the greatest potential for natural gas substitution for coal is expected in the East South Central (ESC) and South Atlantic (SA) Census divisions.

- Based on December 2008 average delivered coal prices of $2.58 per million Btu (MMBtu) in the ESC and $3.06 per MMBtu in the SA, a decline in the

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average delivered natural gas price from $4.75 to $4.25 per MMBtu in each region could boost natural gas consumption for baseload electricity generation in the electric power sector by about 2.1 billion cubic feet per day (Bcf/d) in the ESC and SA combined.

- The extent of potential increased natural gas consumption in the electric power sector because of lower natural gas prices relative to coal still remains highly uncertain. The ability of the electric power sector to switch fuels for baseload power generation may also be significantly affected by several other factors such as contractual obligations, particularly for delivered coal, constraints in the capacity of natural gas pipelines or the electric grid transmission system, the availability of gas-fired combined cycle generation capacity and the ability of some regulated electric utilities to pass on costs to consumers.

Introduction

In April 2009 the Henry Hub spot price averaged $3.52 per MMBtu, a decline of 73 percent from its average level in July 2008. The drop in price reflects the combined impact of weak natural gas demand due to the economic downturn and strong domestic natural gas production as production from shale and coalbed methane resources has continued to increase. Total U.S. natural gas consumption increased by 0.4 Bcf/d in the fourth quarter of 2008, compared with the same period the year before, while total U.S. dry natural gas production increased by 3.0 Bcf/d, more than offsetting a 1.0-Bcf/d decline in natural gas net imports. Continued economic weakness is expected to keep prices near their current level throughout the summer and into the fall.

Fuel competition for baseload electricity generation is a crucial factor that may boost natural gas demand over the coming months. This report addresses the potential for increased natural gas consumption by electric generators as the price of natural gas becomes increasingly competitive with coal. The analysis focuses on baseload generation by electric generators in the ESC and SA regions, where the potential for switching is expected to be greatest.

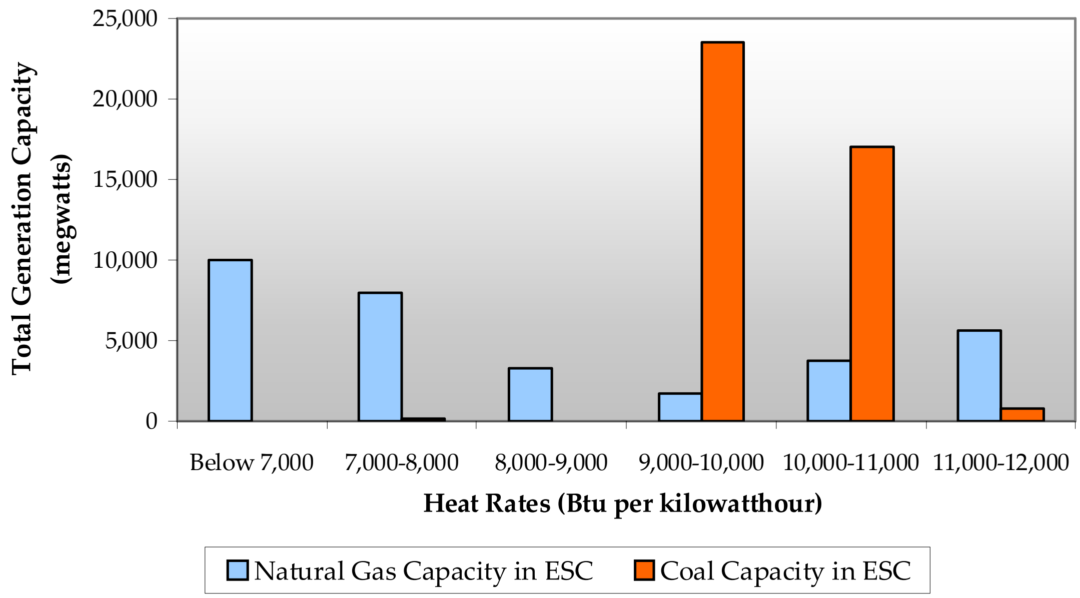
To perform this analysis, generation facility characteristics were used to develop a dispatch, or supply, curve under certain assumed delivered natural gas and coal prices. Actual capacity utilization can be affected by several factors, including, but not limited to, contractual obligations, particularly for delivered coal, coal storage capacity, transmission and natural gas pipeline constraints, and maintenance schedules; however, consideration of these factors is beyond the scope of this analysis. Despite these variables, the analysis of plant-level economics suggests that incremental switching from coal to natural gas could materialize as delivered natural gas prices become more competitive as they fall closer to coal prices.

Heat Rates

The value of natural gas and coal to an electric generator can not be compared directly on a Btu basis since the kilowatt-hours generated for each Btu consumed varies by fuel, by facility burning the same fuel, and by utilization rate. The heat rate, measured as Btu/kWh generated, indicates the amount of fuel required to generate a given amount of electricity. A lower heat rate implies a more efficient plant. Because heat rates tend to be lower at higher utilization rates, particularly for natural-gas-fired generators, the minimum monthly average heat rate observed at each facility in 2008 is used in this analysis to account for higher utilization rates and efficiencies when natural-gas-fired capacity displaces coal-fired generation capacity. The average utilization rate of natural-gas-fired capacity by electric generators was about 13 percent in the ESC in 2008 compared with nearly 68 percent for coal-fired capacity. In the SA, the average utilization of natural-gas-fired capacity by electric generators was about 11 percent in 2008, compared with more than 62 percent for coal.

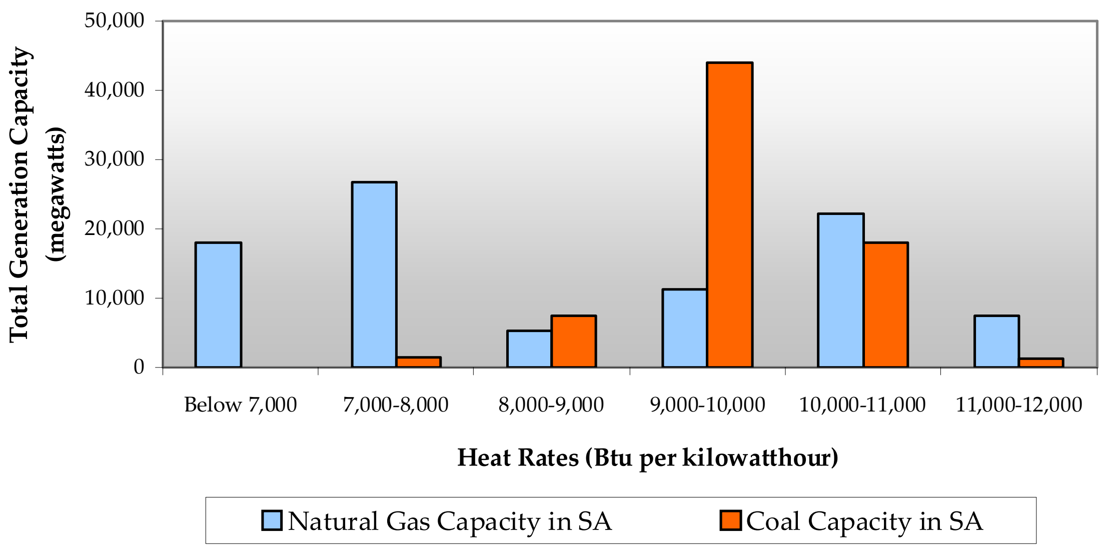
While the average minimum heat rate for an individual electric utility's natural-gas-fired generation unit in the ESC was about 10,000 Btu/kWh in 2008, more than 47 percent of the natural-gas-fired capacity had minimum heat rates below 8,000 Btu/kWh (Figure 1). By comparison, all but one of the electric generators in the ESC burning coal had minimum heat rates of more than 9,000 Btu/kWh, and almost 43 percent of the coal-fired capacity had minimum heat rates higher than 10,000 Btu/kWh. The numbers are similar in the SA (Figure 2). The average minimum heat rate for natural-gas-fired generators in the SA was slightly below 10,000 Btu/kWh in 2008, but more than 42 percent of the natural-gas-fired capacity had minimum heat rates below 8,000 Btu/kWh. Coal-fired generators in the SA had average minimum heat rates of about 10,000 Btu/kWh, while almost 88 percent of the coal-fired capacity had average minimum heat rates of above 9,000 Btu/kWh.

Figure 1. Minimum Monthly AverageHeat Rates for Coal and Natural Gas-Fired Electric Generators in the East South Central (ESC), 2008



Source: Energy Information Administration, EIA-923 and EIA-860.

Figure 2. Minimum Monthly Average Heat Rates for Coal and Natural Gas-Fired Electric Generators in the South Atlantic (SA), 2008



Source: Energy Information Administration, EIA-923 and EIA-860.

The relatively narrow range of heat rates for coal-fired generators in both regions suggests that a large amount of coal-fired capacity could be displaced by natural-gas-fired facilities if delivered fuel prices were to favor switching. If all fuels were priced equally, and absent any other constraints, the most efficient facilities would be dispatched first. However, coal prices have historically been lower than natural gas, which is one reason why less efficient coal-fired facilities have often been dispatched ahead of more efficient natural-gas-fired facilities.

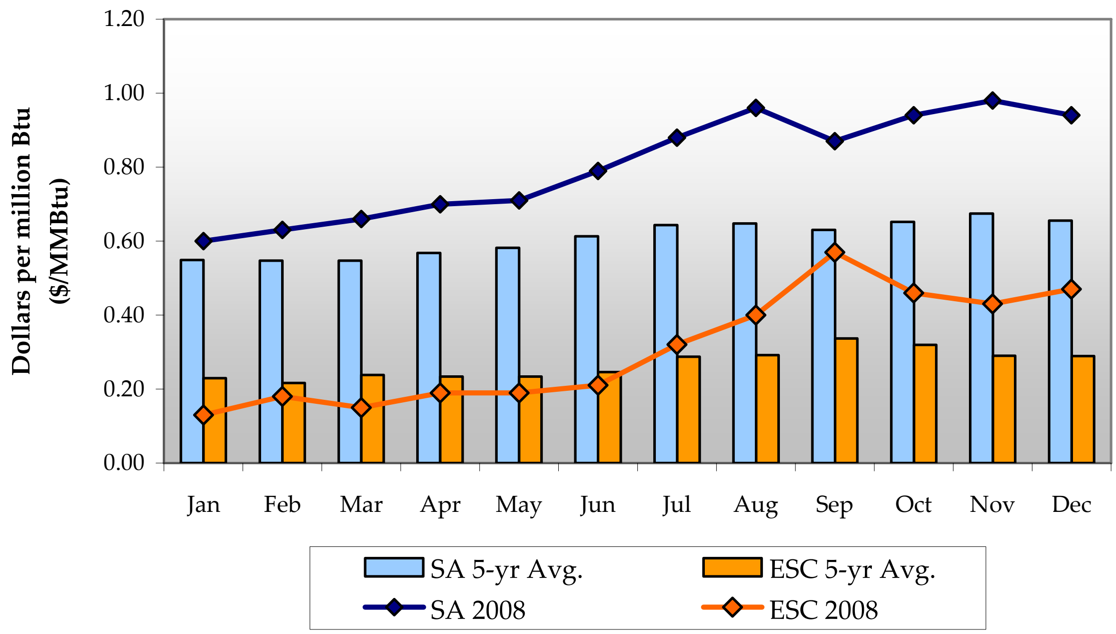
Delivered Fuel Prices

The relative relationship between fuel prices within a particular region can vary considerably from the relationship between those same fuels at the national level. Therefore, fuel prices paid by electric generators could favor natural gas in certain regions of the country during part of the year, even though national average fuel prices may not suggest such a tendency. While price comparisons between delivered fuels can be complicated further by the combination of contract and spot pricing, isolated cases of price convergence could have a notable impact on utilization rates of coal and natural-gas-fired generators.

A short-term convergence among delivered fuel prices for electric generators may cause switching from coal to natural gas for baseload power generation in the Southeast. This analysis is based on the average delivered prices of natural gas and coal to electric generators in the ESC and SA regions. The *Short-Term Energy Outlook* does not provide regional price forecasts for fuels delivered to the electric power sector, only national average prices. However, approximate forecasts of regional fuel prices may be derived from the historical relationships between regional and national average fuel prices.

Coal Prices. Delivered coal prices in both regions have exhibited a fairly uniform differential to the national average delivered coal price over the last 5 years (Figure 3). Delivered coal prices in the SA have historically been slightly less than \$0.50 per MMBtu higher than the national average while delivered coal prices in the ESC have been about \$0.25 higher than the national average. Transportation costs for western Powder River Basin (PRB) coal and increased global demand for eastern Appalachian coal had forced delivered coal prices higher in the SA and ESC regions compared with those in the rest of the United States over the last year. The national average delivered coal price was \$2.24 per MMBtu in January 2009, the most recent month in which data are available. By comparison, the January delivered coal price to electric utilities averaged \$3.29 per MMBtu and \$2.67 per MMBtu in the SA and ESC, respectively.

Figure 3. Previous 5-year Average (2004-2008) Basis Differential between the National Average and Regional Delivered Coal Prices in the East South Central (ESC) and the South Atlantic (SA)



Source: Energy Information Administration, Electric Power Monthly.

Coal-burning electric generators rely on a mix of supply delivered through established contracts and purchases on the spot market. The average delivered price of coal is derived from this combination. While uncertainty about specific coal delivery contract terms make if difficult to ascertain how prices and purchase patterns have changed over the past year, purchases in the spot market, though highly variable, have been somewhat easier to track. North Carolina and West Virginia purchased the highest percentages of spot coal in the SA in 2008, 22.4 and 29.2 percent, respectively. For the ESC, spot coal purchases in Kentucky accounted for 67 percent of the total coal consumed in 2008. Spot purchases averaged about 17 and 9 percent of the total coal received by electric generators in the SA and ESC, respectively, in 2008.

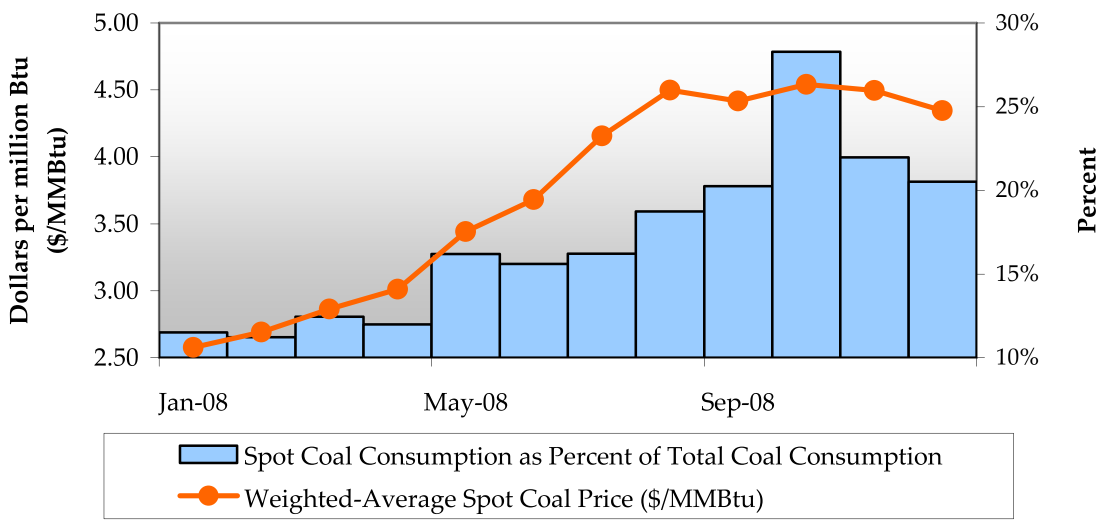
Spot coal prices tend to be higher than prices paid under contract for electric generators. Spot coal prices paid by electric generators averaged $0.84 and $0.66 per MMBtu more than the regional average delivered coal price to electric utilities in the SA and ESC (Figures 4 and 5).[2] Over the course of 2008, electric

[2] Spot price data is not available for independent power producers.

utilities saw spot coal prices rise dramatically relative to the average delivered coal price in both regions. In the SA, the spot-to-regional average coal price differential was $0.08 per MMBtu in January 2008 and peaked at $1.41 per MMBtu in November. In the ESC, this same differential expanded from $0.10 per MMBtu in January 2008 to $1.46 per MMBtu in August.

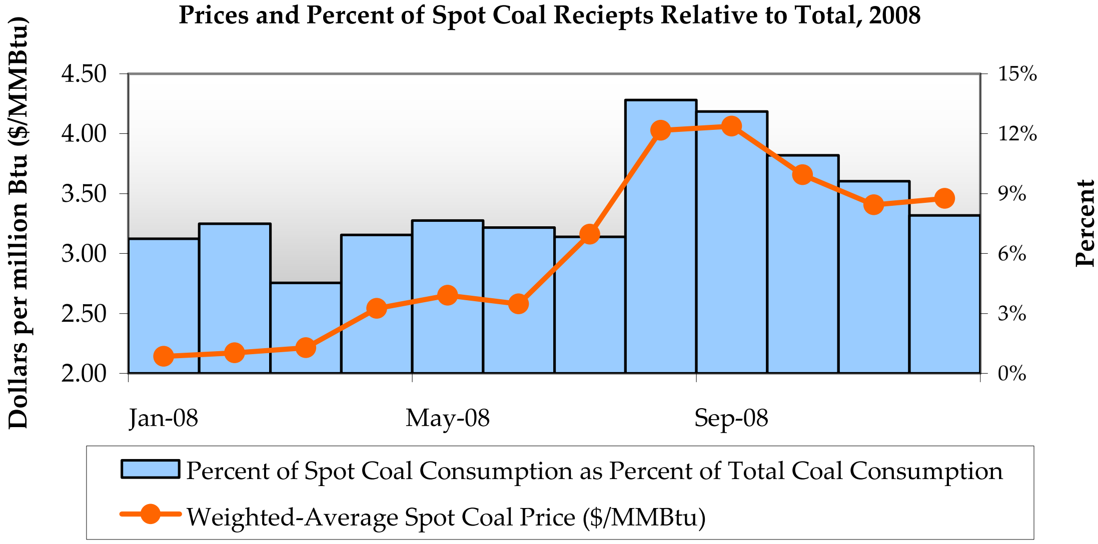
Despite the increase in spot coal prices in 2008, the relative volumes of spot coal receipts increased in both the SA and ESC (Figures 4 and 5). The share of spot coal receipts generally increased throughout 2008 in the SA, roughly doubling from about 1.4 million tons in February to about 2.8 million tons in October, when it accounted for more than 25 percent of coal receipts in the region. By comparison, average monthly spot coal receipts in the ESC accounted for about 9 percent of the total monthly coal receipts in 2008, peaking at 14 percent in August.

Figure 4. South Atlantic: Electric Utility Weighted-Average Spot Coal Prices and Percent of Spot Coal Consumption Relative to Total, 2008



Source: Energy Information Administration, EIA 923.

Figure 5. East South Central: Electric Utility Weighted Average Spot Coal Prices and Percent of Spot Coal Reciepts Relative to Total, 2008

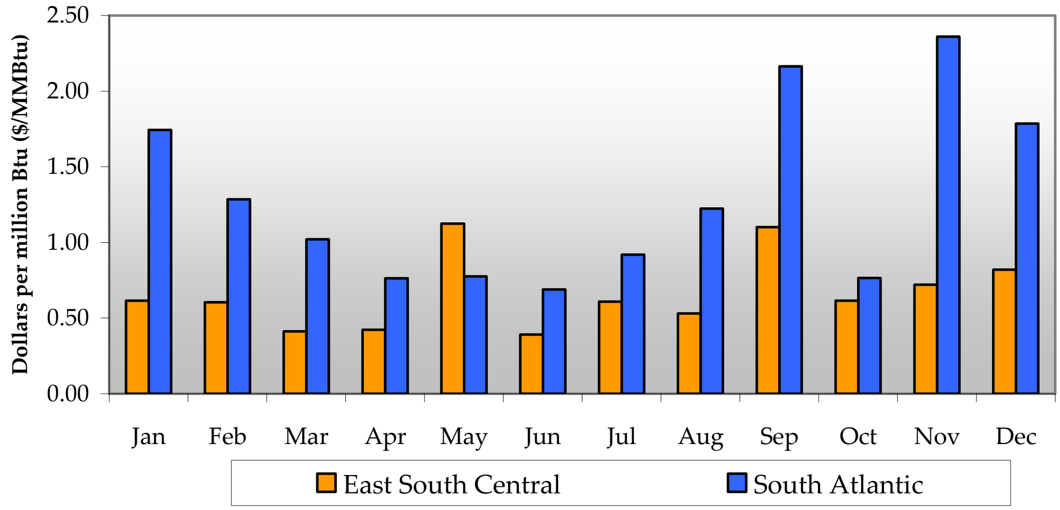


Source: Energy Information Administration, EIA 923.

At the minemouth, before transportation costs are added, the spot price of Central Appalachian fell from about $5.60 per MMBtu (based on 12,500 Btu per pound or about $140 per ton) in mid-September 2008 to about $2.60 per MMBtu, about $65 per ton, in late-January 2009. Over this same period, the national average delivered coal price remained about $2.20 per MMBtu. By late-April 2009, Central Appalachian spot coal prices have actually increased slightly to average of less than $2.80 per MMBtu, about $70 per ton. However, it remains unclear whether the dramatic decline in spot coal prices has begun to reduce the national average price of coal delivered to electric generators.

Natural Gas Prices. Delivered natural gas prices tend to be lower in the SA and ESC than in surrounding regions. Delivered natural gas prices, however, also tend to vary considerably over the course of a year because of seasonal demand variations and regional pipeline constraints. The previous 5-year average (2004-2008) differential between the Henry Hub spot price and the regional delivered natural gas price ranged between $0.69 and $2.36 per MMBtu in the SA and $0.39 and $1.12 per MMBtu in the ESC (Figure 6). In April 2009, the Henry Hub spot price averaged $3.52 per MMBtu. Based on historical averages, this corresponds to a minimum delivered natural gas price of about $4.20 per MMBtu in the SA and $3.90 per MMBtu in the ESC.

Figure 6. Previous 5-year Average (2004-2008) Basis Differential between the Henry Hub Spot Price and the Regional Delivered Natural Gas Price in ESC and SAC



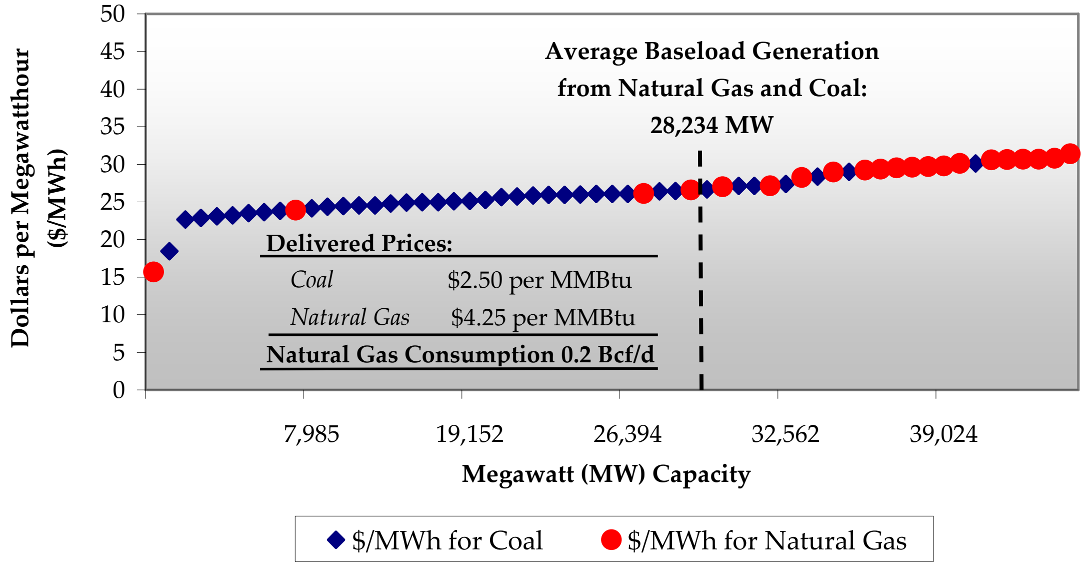
Source: Energy Information Administration, Electric Power Monthly.

While lower natural gas prices relative to coal could create an economic incentive to shift from coal-fired capacity to natural-gas-fired capacity among electric generators, the comparative economics can be somewhat difficult to assess due to uncertainties about the price for delivered coal. Coal contracts that include price-lag mechanisms and take-or-pay clauses may restrict the substitution of natural gas for coal. However, contracted minimum-delivery levels may still provide generators the opportunity to marginally adjust the amount of coal they receive. Furthermore, natural gas pipeline operators may temporarily discount transportation rates when incremental capacity is available to increase short-term competitiveness with coal. As will be shown, small adjustments in coal consumption can lead to sizable changes in natural gas consumption (either increasing or decreasing) by electric generators. Nevertheless, as the differential between relative delivered fuel prices narrows, incremental switching from coal to natural gas would cause natural gas consumption to increase and hinder a further decline in natural gas prices.

The Dispatch Curve

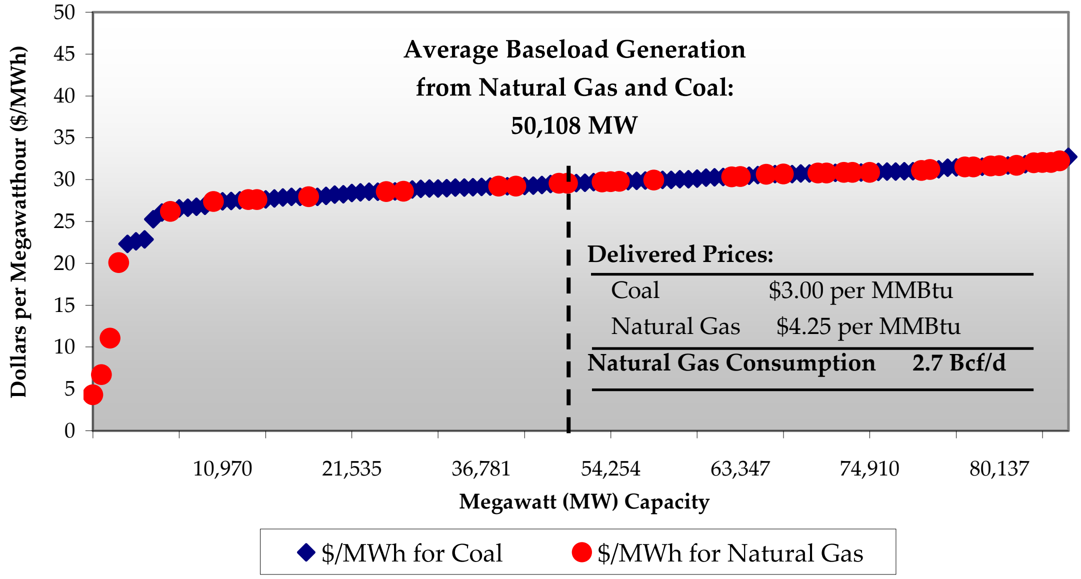
A simple measure of the generation cost for each facility can be determined by combining the facility's heat rate with the delivered fuel price. This analysis ignores other costs such as emissions allowances and other variable operating and maintenance costs. Facilities with the lowest generation cost will generally be deployed first (Figures 7 and 8). As electricity demand increases, the next higher cost capacity will be utilized. Due to the distribution of heat rates for various coal- and natural-gas-fired electric power facilities discussed above, a significant amount of coal-to-gas switching is possible as delivered prices converge.

Figure 7. Estimated Dispatch Curve of Coal and Natural Gas-Fired Baseload Generation Capacity from Electric Utilities in the East South Central



Source: Energy Information Administration, EIA-923 and EIA-860.

Figure 8. Estimated Dispatch Curve of Coal and Natural Gas-Fired Baseload Generation Capacity from Electric Utilities in the South Atlantic



Source: Energy Information Administration, EIA-923 and EIA-860.

Delivered coal prices in December 2008 averaged about $2.50 per MMBtu in the ESC and about $3 per MMBtu in the SA. Assuming that delivered coal prices will be slow to change, the amount of natural-gas-fired capacity that could be economically dispatched increases as the delivered price of natural gas falls (Table 1). The minimum level of natural gas consumption for baseload electricity generation is about 0.8 Bcf/d for the ESC and SA combined (0.1 Bcf/d in the ESC and 0.7 Bcf/d in the SA). A decline in the average delivered natural gas price from $4.75 to $4.25 per MMBtu in each region could boost natural gas consumption for baseload electricity generation in the electric power sector from 0.8 to about 2.9 Bcf/d in the ESC and SA combined.

While the differential, or spread, between delivered coal and natural gas prices is important for estimating the capacity utilization of the different facilities, the impact of the differential depends on the level of prices as well. Assuming a consistent spread of $1 per MMBtu between the delivered coal and natural gas prices, natural gas consumption is estimated to be lower at lower delivered prices of both fuels (Figure 9). This point is perhaps best illustrated with a straightforward example. For simplicity sake, assume the average natural-gas-fired generator has a heat rate of 8,000 Btu/kWh and the average coal-fired generator has a heat rate of 10,000 Btu/kWh. If the delivered price of coal is $1 per MMBtu, then the generation cost for the average coal generator is $10 per

MWh. Therefore, based on the ratio of heat rates, a delivered natural gas price of $1.25 per MMBtu (or 25 percent greater than the delivered price of coal) would result in an equivalent $10 per MWh generation cost for the average natural-gas-fired generator.

Table 1. Electric Power Sector Natural Gas Consumption with Fixed Delivered Coal Prices and Various Delivered Natural Gas Prices

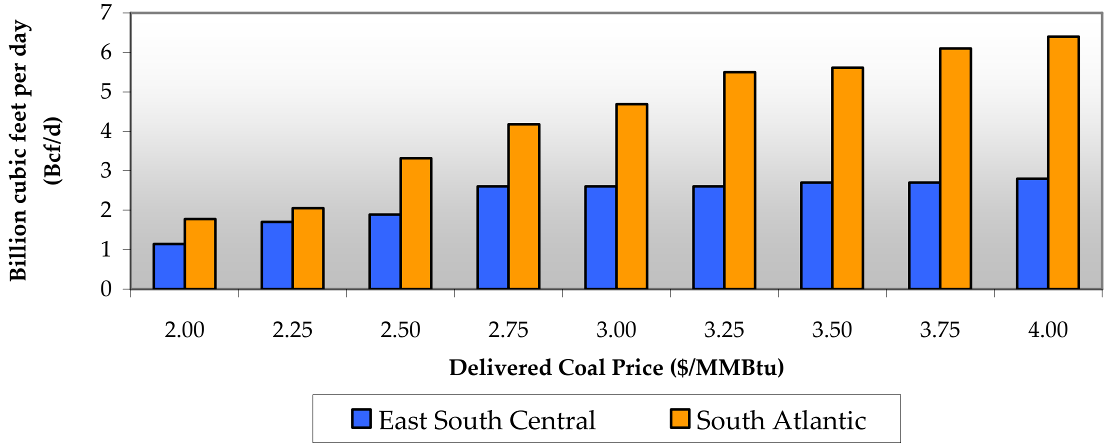
	East South Central	South Atlantic
Delivered Coal Price (dollars per million Btu)	$2.50	$3.00

	Electric Power Sector Natural Gas Consumption (Bcf/d)	
Delivered Natural Gas Price (dollars per million Btu)	**East South Central**	**South Atlantic**
$3.50	1.9	7.2
$3.75	1.1	6.4
$4.00	0.6	4.7
$4.25	0.2	2.7
$4.50	0.1	1.8
$4.75	0.1	0.7

Source: EIA calculations.

Historically, delivered coal prices have been less responsive to changing market conditions than delivered natural gas prices. On the other hand, if delivered coal prices decline commensurately with the delivered price of natural gas, then it is expected that less switching will occur and potential increases in natural gas consumption will be limited. Moreover, the actual volume of fuel switching would likely be lower because of several factors such as contractual obligations, particularly for delivered coal, constraints in the capacity of natural gas pipelines or the electric grid transmission system, and the ability of some regulated electric utilities to pass on costs to consumers.

Figure 9. Natural Gas Consumption at Constant $1.00 per MMBtu Delivered Coal-to-Gas Price Spread



Source: EIA calculations.

Conclusion

The recent decline in natural gas prices has enhanced the potential for the displacement of baseload coal-fired generation capacity with natural-gas-fired generation capacity, particularly for electric generators in the ESC and SA. Electric generators facing relatively high and rigid delivered coal prices in the short-term have an economic incentive to increase natural gas consumption in response to the decline in the price of natural gas natural gas relative to coal. On the other hand, if delivered coal prices decline commensurately with the price of delivered natural gas, then the amount of switching from coal- to natural-gas-fired capacity is expected to be limited. Actual capacity utilization also may also be affected by several factors beyond plant-level economics, including contractual obligations, particularly for delivered coal, electricity transmission and natural gas pipeline constraints, and maintenance schedules. As a result, coal capacity may continue to be utilized at high rates than indicated by this analysis even in the case of lower sustained natural gas prices. Yet, while the extent of potential increased natural gas consumption is difficult to determine, an analysis of plant-level economics reveals that natural-gas-fired capacity could begin to displace coal-fired capacity among electric generators as long as the differential between delivered prices narrows.

Appendix - Data and Methodology

Heat rates, utilization rates, and capacity factors for coal and natural-gas-fired electric generators were calculated using data from the following EIA surveys:

- EIA-423, Monthly Report on Cost and Quality of Fuels for Electric Plants,
- EIA-906, Power Plant Report,
- EIA-923, Power Plant Operations Report, and
- EIA-860, Annual Electric Generator Report.

Industrial and commercial cogenerators in the databases were excluded from this analysis as well as observations where the Facility ID Number was 99999 corresponding to an EIA estimate for non-sampled plants. Facilities with calculated utilization rates greater than 1 (or 100 percent), less than 0 (negative) or zero were also discarded in order to eliminate potential outliers. These outliers appeared more often in the population of natural-gas-fired facilities because of historically low utilization and inconsistent data. In addition, all fuel consumption data for each natural gas combined-cycle facility in the database was aggregated, combining fuel consumed for both useful thermal output and electricity generation. Historical average delivered fuel prices by region are from EIA's Electric Power Monthly (EPM), Table 4.10.A and Table 4.13A. Average hourly generation load estimates were also derived from the EPM, Tables 1.6A, 1.7A, and 1.10A. Spot coal prices and volumes consumed in the electric power sector are from the EIA-423 and EIA-923 databases, and total coal volumes consumed are from the EPM, Table 2.5.A.

Generation cost values for each plant were created by combining the heat rates for coal and natural gas facilities with the corresponding price of delivered fuel in the region. In this calculation the minimum monthly average heat rate recorded in 2008 was taken for each facility.

(1) Heat Rate (MMBtu/MWh) x Delivered Fuel Price ($/MMBtu) = Generation Cost ($/MWh)

Based on the relative delivered fuel prices, a preferred dispatch series was generated in which facilities were rank ordered based on generation cost. Capacity factors and utilization rates were then calculated to determine the incremental additions from each facility in the preferred dispatch series. The capacity utilization of each coal plant was assumed to be equivalent to the average monthly utilization rate of the particular facility in 2008. Natural-gas-fired facilities were assigned a uniform utilization rate of 85 percent, well above the historical average for these units.

(2) Facility Capacity (MW) x Utilization Rate = Facility Contribution to Baseload Generation Requirement

Baseload generation requirements of coal and natural-gas-fired facilities, excluding all other generation sources, are represented by the average hourly load for these units in the month of March 2008, when generation needs are typically at a minimum and representative of baseload. Finally, delivered fuel prices were varied for both natural gas and coal to assess the sensitivities associated with these price relationships and the dispatch results that determine the amount of fuel switching that might occur among baseload units.

Appendix – Errata and Revisions

May 13, 2009 - Spot coal prices in dollars per million Btu on page 8 were corrected.