

**BEFORE THE
SURFACE TRANSPORTATION BOARD**

STB EX PARTE NO. 717

ENTERED
Office of Proceedings
November 26, 2012
Part of
Public Record

**PETITION OF THE ASSOCIATION OF AMERICAN RAILROADS
TO INSTITUTE A RULEMAKING PROCEEDING TO REINTRODUCE
INDIRECT COMPETITION AS A FACTOR CONSIDERED IN MARKET
DOMINANCE DETERMINATIONS FOR COAL TRANSPORTED TO
UTILITY GENERATION FACILITIES**

**COMMENTS OF
NORFOLK SOUTHERN RAILWAY COMPANY**

**James A. Hixon
John M. Scheib
David L. Coleman
Garrett D. Urban
Norfolk Southern Corporation
Three Commercial Place
Norfolk, VA 23510**

***Counsel for Norfolk Southern
Railway Company***

Dated: November 26, 2012

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Norfolk Southern Railway Company (“NS”) submits these Comments in support of the November 19, 2012, Petition of the Association of the American Railroads To Institute a Rulemaking Proceeding To Reintroduce Indirect Competition as a Factor Considered in Market Dominance Determinations for Coal Transported to Utility Generation Facilities (“Petition”). NS joins in the Petition of the Association of American Railroads (“AAR”) and agrees in full that dramatic changes in the electric power markets combined with the development of readily available evidentiary sources necessitate a reconsideration of the Surface Transportation Board’s (“Board” or “STB”) prohibition on the introduction and consideration of evidence of product and geographic competition (generally, “indirect competition”) in coal rate cases brought by utility generation facilities. NS offers the following comments to supplement and support the AAR’s Petition and emphasize the abrupt transformation that has occurred in wholesale power and natural gas markets generally within the past few years, especially within NS’s territory in the eastern United States, and its impact on the economic decisions utilities make when dispatching certain coal-fired power plants.

To be clear, NS is not saying that every coal-fired power plant is subject to indirect competition. However, the changes in the production of gas mean more coal-fired plants are subject to such competition. Moreover, the changes in the wholesale markets discussed in the AAR's Petition allow for the easy and inexpensive presentation of evidence to determine in individual cases whether a particular coal-fired power plant is subject to indirect competition.

Introduction

A real and dramatic change has occurred generally in the electric power markets within the past few years. Gas-fired power plants are competing with coal-fired power plants on an unprecedented level, such that they are in some cases displacing electricity generated from coal and even causing some coal-fired power plants to be mothballed. The public press is widely documenting this fierce competition. For example it is reported that:

- The United States is experiencing an historic combination of low natural gas prices and rising costs of burning coal.¹
- Utility company CEOs have noted that the economics dictate that they should shift from producing electricity from coal towards producing from gas when possible.
 - The chairman of the largest coal-burning utility in the United States commented this spring that “[t]he math screams at you to do gas.”²
 - Luminant, a utility in Texas, has observed that its decision on fuel sources is “all about low wholesale prices,” and it is placing coal-fired plants into semiretirement because natural gas-fired plants set market prices in Texas and their costs are so low that they often sell power for less than what it costs to run a coal plant.³

¹ See Eric Lipton, *Even in Coal Country, the Fight for an Industry*, N.Y. Times, May 29, 2012, at A1 (concluding that “the economics of coal have been transformed”); Liam Denning, *Railroads Run Out of Steam at the Coal Face*, Wall St. J., Mar. 17, 2012, at B16.

² Eric Lipton, *Even in Coal Country, the Fight for an Industry*, N.Y. Times, May 29, 2012, at A1 (quoting AEP Chairman Michael Morris).

³ Rebecca Smith, *Coal Fired Power Plants Mothballed by Gas Glut*, Wall St. J., Sept. 12, 2012, at B1.

- Southern Co. executives reported on their first quarter 2012 earnings call that in 2007, the company's electricity production was 16% natural gas and 70% coal. They now expect that the mix for 2012 will be 47% natural gas and only 35% coal. Its natural gas combined cycle plants have been operating at a 70% capacity factor, and the company estimates that its purchases of natural gas made up 2% of total gas consumption in the U.S.⁴
- Gas industry executives are touting the extent to which gas-fired electricity generation is displacing coal-fired generation. The Star-Telegram reported that at Exxon Mobil's shareholder meeting, CEO Rex Tillerson said natural gas will continue to displace coal for power generation.⁵
- Utility executives in the East confirm that this indirect competition with coal-fired power plants exists and that they are exploiting it to their advantage.
 - Lynn Good, Duke Energy Corporation's Chief Financial Officer, told investors and analysts: "If the coal is in the money, we run them. If it's not in the money, we don't. And maintain flexibility in the way we contract for coal to make that operationally successful."⁶
 - Thomas Fanning, Southern Company's CEO, recently touted Southern's fuel "flexibility," saying "[t]here remains excellent optionality in our generation fleet."⁷

The accuracy of such observations is evident when examining the transformation of the marketplace. In January of 2012, the Energy Information Administration ("EIA") reported that

⁴ Susan Tierney, *Why Coal Plants Retire: Power Market Fundamentals as of 2012*, CoalPower, July 30, 2012.

⁵ Jim Fuquay, *Exxon CEO: Power generation is best hope for natural gas*, Star-Telegram, May 30, 2012, available at <http://www.star-telegram.com/2012/05/30/3996945/exxon-ceo-power-generation-is.html#storylink=cpy>.

⁶ Duke Energy Corporation, Q4 2011 Earnings Call, Feb. 16, 2012, available at <http://www.duke-energy.com/pdfs/Q42011-DUKE-Transcript-2-16-2012.pdf>.

⁷ Southern Company, Q1 2012 Earnings Call, Apr. 25, 2012, available at <http://seekingalpha.com/article/529581-southern-s-ceo-discusses-q1-2012-results-earnings-call-transcript>.

the proportion of electric power generated by coal in the U.S. fell below the percentage generated by natural gas and renewable fuels for the first time in American history.⁸

Low natural gas prices and abundant supply of natural gas have changed the electric power industry's responses to new environmental regulations by altering the relative costs and economics of gas-fired-generation in comparison to coal-fired generation and accompanying pollution control costs. These synergistic effects impact utility companies' economic determinations of the order in which they dispatch their power plants, which in some cases has resulted in displacement of coal-fired generation. Over the coming years, these changes will further affect investment decisions to build or maintain certain coal-fired plants. Such effects are compounded in the eastern United States, where eastern coal faces increased environmental regulation and higher extraction costs, further driving up its price and the competitive advantages of natural gas. Given these real market effects, the STB should permit parties to present evidence of whether indirect competition precludes a railroad from exerting market dominance for transportation of coal to a particular coal-fired power plant when a utility company brings a rate challenge to coal transportation rates.

In the remainder of this filing, Norfolk Southern outlines the dramatic changes that have occurred in the electricity generating market generally – without taking a position on whether the indirect competition generally described contains rail transportation rates for coal to any specific, individual coal-fired power plant.

I. The Natural Gas “Revolution” – Coal and Gas Competition

The rise in natural gas power generation over the past few years, driven by the fall in the cost of natural gas production, has caused widespread switching from coal to natural gas by

⁸ See *An Historic Day in United States Power Generation*, Refueling Energy, Mar. 27, 2012.

utilities on a scale that the news media has labeled a “revolution.” See Steven Mufson, *The Demise of Coal Fired Power Plants*, Wash. Post, Nov. 23, 2012; Liam Denning, *Railroads Run Out of Steam at the Coal Face*, Wall St. J., Mar. 17, 2012, at B16; Jesse Gilbert & Steve Piper, *Stage set for significant coal-to-gas switching in remainder of 2012*, UAE Weekly Energy Brief, Apr. 29, 2012 (“Dispatch competition between U.S. coal and natural gas fleets represents one of the key factors dramatically reshaping energy markets.”). Abundant supply of natural gas and historically low natural gas prices are primarily the result of the increasing use of hydraulic fracturing technology, or “fracking,” to economically extract abundant natural gas from shale, sandstone, limestone, and other porous rock formations. See Russell Gold et al., *Glut Hits Natural-Gas Prices*, Wall St. J., Jan. 12, 2012. In addition, high oil prices have caused petroleum companies to expand oil exploration and drilling, which produces natural gas as a byproduct. See *id.* (“High oil prices effectively subsidize the production of otherwise unprofitable natural gas.”). Natural gas supplies are presently so high that there is little-to-no storage capacity remaining—some U.S. oil producers “flare” gas at the wellhead because they have no remaining storage or transportation capacity. See *id.*

When the excess supply of natural gas began to materialize in late 2010 and surplus gas had no other place to go, producers looked to the power market and reduced their prices to the levels needed to penetrate the market by displacing coal in power generation. Natural gas spot prices have fallen from over \$12.50 per million British Thermal Units (“MMBtu”) in 2008 to under \$2.00 MMBtu in April of this year, declining 32 percent in 2011 alone. See EIA, Henry Hub Gulf Coast Natural Spot Price, <http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm>, last accessed Nov. 19, 2012; Russell Gold et al., *Glut Hits Natural-Gas Prices*, Wall St. J., Jan. 12,

2012.⁹ As a result, according to the EIA, the proportion of electricity generated by coal in the U.S. during 2011 was the lowest it has been in 60 years. See Jonathan Fahey, *US Coal Use Falling Fast as Utilities Switch to Gas*, USA Today, June 12, 2012; EIA's Annual Energy Review, Table 8.2a (Sept. 27, 2012). In January 2012, the proportion of electric power generated by coal in the U.S. fell below the percentage generated by natural gas and renewable fuels for the first time in American history. See *An Historic Day in United States Power Generation*, Refueling Energy, Mar. 27, 2012 (showing that coal represented 42 percent of total US electric power generation in 2011, but declined to 38 percent in January 2012, compared to 40 percent generated by natural gas and renewable fuels). Several sources predict that for the full year 2012, coal will account for less than 40 percent of all electricity generated in the United States, the lowest share since World War II. See Jonathan Fahey, *US Coal Use Falling Fast as Utilities Switch to Gas*, USA Today, June 12, 2012 (further reporting that natural gas will account for 30 percent of U.S. electric power production in 2012, and predicting that coal will fall from 50 percent of U.S. power generation in 2008 to near 30 percent by 2019); Jeffrey Tomich, *Constraints Cool Down Coal: Sliding Demand Is Blamed on Lower Natural Gas Prices, Increased Regulation*, St. Louis Post-Dispatch, Apr. 8, 2012, at E1.

II. Competition from Natural Gas Is Enhanced by New Environmental Regulations

Beyond new and greater supplies of natural gas, new environmental regulations have also dramatically changed the economic calculus for coal-fired electricity generation. According to the Government Accountability Office ("GAO"), the North American Electric Reliability Corporation ("NERC"), and numerous other coal and electric power agency experts, significant

⁹ Utilities have seen total natural gas prices as low as \$2.30 MMBtu. See *A sign of the times*, U.S. Coal Review, No. 1898, Mar. 12, 2012 (quoting a Midwestern utility official as stating "[g]as is coming into our turbines at \$2.30 [per million BTUs] now, which is nothing").

new regulations instituted in the last few years will substantially increase the costs of coal-fired generation of electric power, and therefore heighten competition from natural gas.

Most immediate is the Environmental Protection Agency's ("EPA") new Mercury and Air Toxics Standards ("MATS"), which the EPA finalized and issued in February 2012.¹⁰ This new rule sets stringent limits – based upon "maximum achievable control technology" – on coal-fired power plants' emissions of mercury, acid gases (including hydrogen chloride), and non-mercury hazardous air pollutants. All coal-fired stations must meet the new emissions standards – allowance trading and reduced unit use may not be used to achieve compliance. Significantly, the EPA found that regulation of emissions of these pollutants from natural gas-fired generating plants was not necessary or appropriate. *See, e.g.*, GAO Report: EPA Regulations and Electricity, at 13, n.16 (July 17, 2012) ("EPA Regulations and Electricity"). The rule requires all covered coal-fired and oil-fired units to come into compliance as expeditiously as possible but in any event no later than three years after the effective date of the rule, or by early 2015.¹¹

The EPA's own estimates put the cost to utility companies of compliance with the MATS rule at approximately \$10.2 *billion* by 2016.¹² *See* EPA Regulations and Electricity, at 14. Estimates of the number of coal-fired power plant closures and retirements due to this single regulation vary, but nearly all experts are in agreement that the number will be large and significant. *See, e.g., id.*; NERC, Potential Impacts of Future Environmental Regulations (Nov.

¹⁰ See National Emission Standards for Hazardous Air pollutants from Coal-and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012).

¹¹ A one-year extension may be granted for units that can demonstrate such an extension is "necessary for the installation of controls" required to meet the MATS emissions limits. *See id.* at 9407 (discussing Section 112 of the Clean Air Act).

¹² In 2007 dollars, EPA estimated compliance, monitoring, and reporting costs at \$9.6 billion. *See id.* at 9306.

2011); David Harrison Jr. et al., Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations, NERA Economic Consulting (Sept. 2011).

Other regulations currently being litigated or promulgated are sure to have similar effects. First, in June of 2010, the EPA issued a proposed rule related to the regulation of coal combustion residuals (also referred to as coal combustion waste or more loosely as coal ash) under the Resource Conservation and Recovery Act (RCRA). David Harrison Jr. et al., Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations, NERA Economic Consulting, at 7 (Sept. 2011). The regulations apply to the management of coal combustion residuals produced by steam electric power plants that are disposed of in landfills and surface impoundments. The final rule may be issued by the end of 2012. Additionally, proposed regulation of cooling water processes and facilities would further increase costs of coal-fired power generation.¹³ In April 2011, the EPA published proposed standards for cooling water intake structures at all existing power generating facilities and existing manufacturing and industrial facilities pursuant to Section 316(b) of the Clean Water Act (CWA). *Id.* The EPA recently announced that it plans to issue the final rule in June 2013, and estimates the cost of implementing necessary controls and process changes at approximately \$400 million per year. *See EPA Regulations and Electricity*, at 17. Although the precise impacts of these rules on the cost of coal-fired power generation cannot be estimated with any precision, it is clear that impending regulation and compliance costs will further enhance the competitive advantages of natural gas generally.¹⁴

¹³ While gas-fired units also use cooling water, coal-fired units generally use more water and therefore would be disproportionately affected by this regulation.

¹⁴ As the Government Accountability Office recently noted, “power plants that burn coal produce more than 90 times as much sulfur dioxide, five times as much nitrogen oxide and twice

III. Large Utility Companies Are Dispatching Coal-Fired Generation Based on Marginal Price Competition with Natural Gas-Fired Generation

The combination of historically low natural gas prices and increasing costs of burning coal is so compelling that the chairman of the largest coal-burning utility in the United States commented this spring that today “[t]he math screams at you to do gas.” Eric Lipton, *Even in Coal Country, the Fight for an Industry*, N.Y. Times, May 29, 2012, at A1 (quoting AEP Chairman Michael Morris). Nicholas Akins, AEP’s Chief Executive Officer, described the change in natural gas pricing as a “black swan event,” going on to say that “there was always an assumption that coal is going to be lower than natural gas. Well, that’s not the case, so we need to be flexible,” in both gas and coal-fired generation. AEP Q1 2012 Earnings Call, Apr. 20, 2012, available at <http://seekingalpha.com/article/514591-american-electric-power-s-ceo-discusses-q1-2012-results-earnings-call-transcript>. Industry observers believe this natural gas “glut,” and accompanying rock bottom gas prices, will continue at least through 2013. Russell Gold et al., *Glut Hits Natural-Gas Prices*, Wall St. J., Jan. 12, 2012. In the face of such a shift in economics, large utility companies have made clear that they are constantly evaluating their decisions about how to dispatch their fleets based on the relative marginal costs of coal-powered generation versus natural-gas generation and other sources of power generation. *See, e.g.*, Steven Mufson, *The Demise of Coal Fired Power Plants*, Wash. Post, Nov. 23, 2012 (discussing a coal power plant in Salem, MA, which now “runs only when the regional grid managers call on it – which they do based on the weather and the prices at which competing power plants are offering electric power”). Thus, coal transportation rates, which directly impact a coal-powered facility’s marginal cost, are constrained by indirect competition for those coal-fired plants whose

as much carbon dioxide as those that run on natural gas.” Jonathan Fahey, *US Coal Use Falling Fast as Utilities Switch to Gas*, USA Today, June 12, 2012.

utilization fluctuates based on their relative marginal cost compared to natural gas-fired plants or other competitive options.

Over the past two years, utility companies and their executives have repeatedly emphasized that they determine the extent to which they run some of their coal-fired power facilities based on the relative marginal cost of operating their other power facilities. Lynn Good, Duke Energy Corporation's Chief Financial Officer, spoke to the importance of costs in dispatching coal-fired generation: "If the coal is in the money, we run them. If it's not in the money, we don't. And maintain flexibility in the way we contract for coal to make that operationally successful." Duke Energy Corporation, Q4 2011 Earnings Call, Feb. 16, 2012, available at <http://www.duke-energy.com/pdfs/Q42011-DUKE-Transcript-2-16-2012.pdf>. Jim Rogers, Duke Energy's CEO, was even more direct a few months ago when explaining the economics of Duke's decision to run its natural gas and coal plants: "Today we're dispatching hydro first, then our nuclear, then natural gas before our even our [sic] most efficient coal plants. Gas prices have to go above \$4.25 per mmbtu before we start dispatching our most efficient coal." *Technology is Reinventing the Utility Industry at Duke Energy: Jim Rogers*, AOL Energy, June 18, 2012, <http://energy.aol.com/2012/06/18/technology-is-reinventing-the-utility-industry-at-duke-energy-j/?icid=trending1>.

The impacts of competition, and the accompanying calculations, further vary based on the economics of individual power plants and their accompanying coal sources. Thomas Fanning, Chief Executive Officer of Southern Company, detailed the individual determinations his company makes based on the relative price of natural gas when dispatching its coal resources:

Gas at \$1.25 per million Btu...it has to fall below that before it dispatches ahead of nuclear, and frankly (the same is true) at Kemper County (integrated

gasification combined cycle facility expected to begin commercial operation in early 2014). Kemper County will be in the same neighborhood.

When we think about PRB [Powder River Basin coal], you have gas in the range of \$3-4, call it \$3.50 for gas to dispatch ahead of PRB. That would be Scherer [coal-fired power plant in Juliette, GA] and Miller [coal-fired power plant outside Birmingham, AL].

...

We used to say Central App coal was kind of \$6.00- 6.50. Now with Illinois being a more important part of the future as we conform with MATS, that number looks more like \$5.00-6.00, somewhere in there.

Coal's heartaches by the numbers could change as Southern has fuel flexibility, U.S. Coal Review, No. 1933, Nov. 12, 2012, at 4.

With natural gas prices dipping under \$2.00 MMBtu earlier this year, see EIA, Henry Hub Gulf Coast Natural Spot Price, available at <http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm>, these economics have driven Duke Energy and Southern Company to utilize natural gas resources ahead of coal. Susan Tierney, *Why Coal Plants Retire: Power Market Fundamentals as of 2012*, CoalPower, July 30, 2012 (reporting Southern's electricity production mix fell from 70% coal to only 35% coal between 2007 and 2012). Similarly, Calpine Corporation disclosed in its 2011 10-K, filed in February of 2012, that "[n]atural gas-fired combined-cycle units in many markets are now frequently cheaper to dispatch than coal-fired power plants," going on to explain that "[n]atural gas prices in some parts of the country for parts of 2009, 2010 and 2011 were low enough that modern combined-cycle natural gas-fired generation became less expensive on a marginal basis than coal-fired generation. The result was that natural gas displaced coal as a less expensive generation resource resulting in what the industry describes as coal-to-gas switching." Calpine Corporation, 2011 10-K Annual Report, at 8-9 (Feb. 10, 2012), available at <http://phx.corporate-ir.net/phoenix.zhtml?c=103361&p=irol-sec>. Indeed, in reviewing utility after utility, the universal theme is that coal and gas generation are competing and impacting utilities' decisions on how to dispatch their fleet. See also Exelon Corporation,

Q2 2012 Earnings Call, Aug. 1, 2012, available at <http://seekingalpha.com/article/771111-exelon-management-discusses-q2-2012-results-earnings-call-transcript> (discussing the impact of “coal and gas competition”). Therefore, it is clear that certain coal-fired power plants are experiencing indirect competition that is constraining rail transportation rates for coal.

Going forward, utility executives confirm their plans to maintain flexibility in their generation mix to make decisions about energy source utilization based on the relative price of producing coal-fired generation. To be sure, competition from natural gas and environmental regulation will cause many coal power plants to be retired, and prevent others from being constructed in the first place.¹⁵ However, utility companies will maintain diversified resources as part of their energy strategy. Thomas Fanning, Southern Company’s CEO, told investors this year:

There remains excellent optionality in our generation fleet. As an illustration, by 2020, assuming a scenario of low natural gas prices and relatively high coal prices, our energy mix could be 57% gas and 22% coal. If fuel prices change to a high-gas, low-coal environment, the energy mix could be 34% gas and 45% coal. Under all scenarios, nuclear would remain in the 16% to 17% range. This level of flexibility will continue to be an important part of our operational planning philosophy going forward.

Southern Company, Q1 2012 Earnings Call, Apr. 25, 2012, available at <http://seekingalpha.com/article/529581-southern-s-ceo-discusses-q1-2012-results-earnings-call-transcript>. Similarly, Duke Energy Indiana Incorporated’s President Douglas Esamann has said: “I think diversity is still important. . . . I don't think we are going to be putting all of our eggs in the natural gas basket. We have a number of irons in the fire, and I think that's how we are going to continue to look at this.” Jonathan Crawford, *CEOs caution against overreliance on gas-fired*

¹⁵ For example, a survey of electric power producers by the Associated Press this year found that new environmental regulations will cause the closure of 32 to 68 coal-fired plants over the next three years alone. See Jonathan Fahey, *US Coal Use Falling Fast as Utilities Switch to Gas*, USA Today, June 12, 2012.

power, stress diversification, SNL Financial, Mar. 21, 2012.¹⁶ Such strategies demonstrate that utility companies will continue to maintain coal-fired capacity and determine whether, and to what extent, to utilize that capacity based on the relative marginal cost of natural gas and other generation. Coal transportation rates for coal power plants operating at the margins under such conditions are constrained by the operation costs of utilities' natural gas-fired facilities. Thus, large utility companies not only expect but are *actively planning to ensure* that indirect competition continues to impact parts of the coal transportation market for the foreseeable future.

IV. Eastern United States Faces Substantial Impact

The effect of newly abundant supply of natural gas and low gas prices on coal demand has been pronounced in the region served by NS, the eastern United States. Although falling prices for natural gas have clearly impacted national power generation statistics and trends, this impact is not felt uniformly at every coal-fired generation facility. *See Coal's heartaches by the numbers could change as Southern has fuel flexibility*, U.S. Coal Review, No. 1933, Nov. 12, 2012, at 4 (quoting Southern Company's CEO discussing different price points for dispatch of coal power plants using PRB and Central Appalachian coal). Indirect competition may result in scaled back production at some plants, *see* Rebecca Smith, *Coal Fired Power Plants Mothballed by Gas Glut*, Wall St. J., Sept. 12, 2012, at B1 (citing "a growing number of coal-fired plants that were built to run 24 hours a day, seven days a week, but now may run only occasionally because of soft demand for electricity and competition from gas-fired plants that are cheaper to run and cleaner to operate"); however, other coal facilities with lower marginal costs may continue to operate nearly unaffected, at or near normal capacity. Similarly, the regional impact of natural

¹⁶ *See also id.* (quoting Nick Akins, CEO of AEP: "In the end, we will still have a large portion of our generation that is from coal-fired generation. . . . We need everything. That is clear for us going forward.").

gas switching on coal-fired generation and accompanying coal demand varies, and has proven especially severe in the eastern United States. This impact has been compounded by environmental and mining regulations that disproportionately impact coal production in the region, further driving up the price of Appalachia coal against natural gas. As a result, the eastern United States faces increased pressures on coal-fired power generation versus the rest of the country due to the transformation of the market over the last few years.

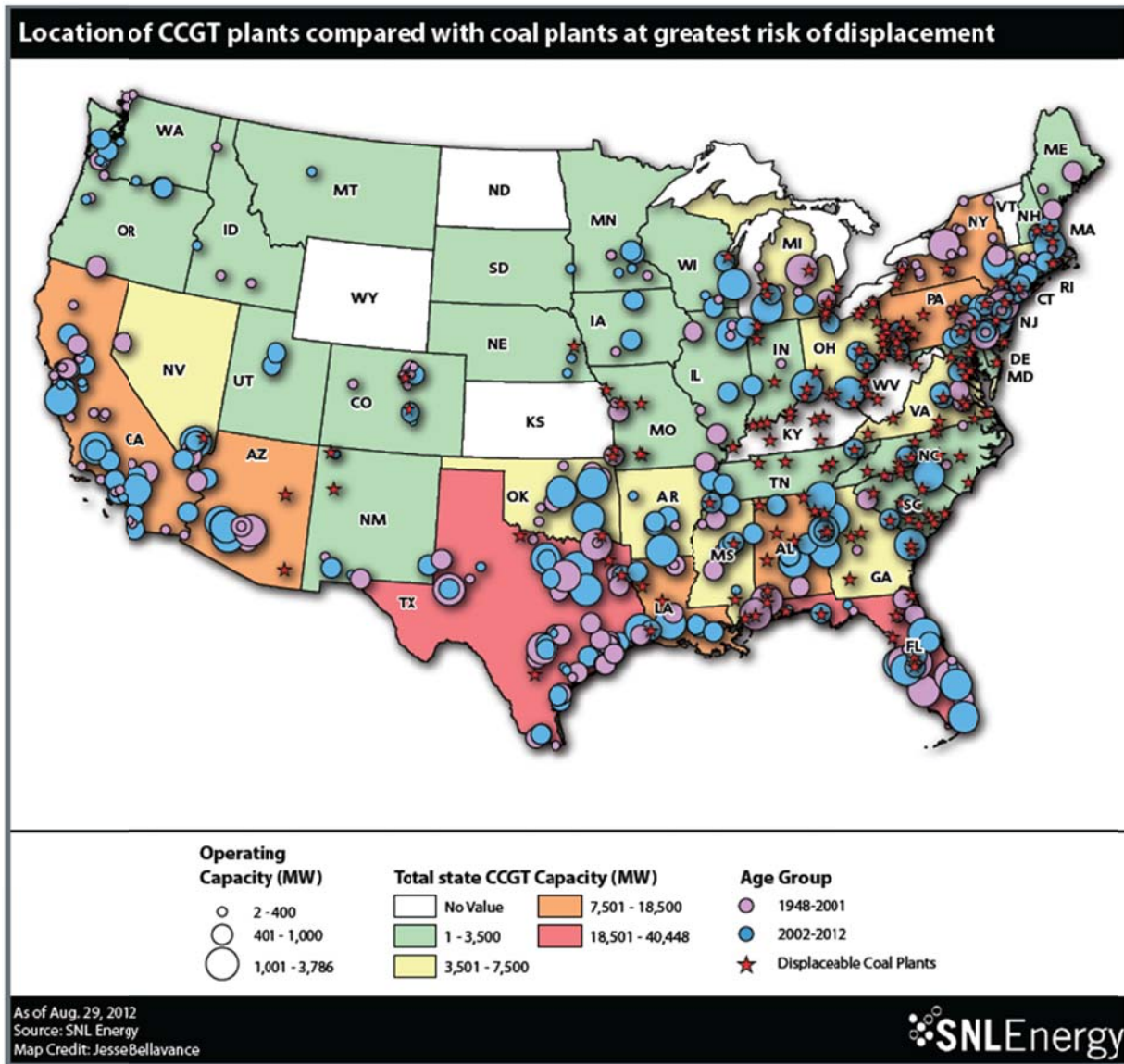
A. Impact of the Natural Gas Revolution in the Eastern United States

Companies based in the eastern United States have responded dramatically to the natural gas revolution. Duke Energy Corporation, one of the largest power generators in the U.S. and a large NS coal transportation customer, told regulators that it expects to burn 40 percent less coal in 2012 than it burned in 2011 in some locations. Rebecca Smith, *Utilities Give Coal the Heave-Ho – Power Plants Abandon Longtime Staple for Generating Electricity as Price of Natural Gas Plummets*, Wall St. J., May 1, 2012, at B6. Progress Energy, a significant NS coal customer in the southeast, is renegotiating coal purchase contracts because it plans to burn less coal. *Id.* Major coal companies such as Arch Coal – the second largest coal producer in the nation -- have been shuttering eastern coal operations. See Dan Lowry, *As Layoffs Mount, Anger Boils Over in Appalachian Coal Country*, SNL Daily Coal Rep., June 25, 2012. “Arch's latest job cuts come on top of previous workforce reductions announced by Arch and other coal producers across the U.S. and particularly in Appalachia, [with] higher-cost operations [that] are unable to compete in an environment of low natural gas prices.” *Id.* Central Appalachian coal mining company Alpha Resources plans to produce 11.5 million fewer tons in 2012 than in 2011, and has announced plans to idle 12 mining operations in Kentucky and West Virginia. In the spring of 2012, Patriot Coal closed a Kentucky mine, idled several more mines in West Virginia and Kentucky, and cut 1000 jobs. Patriot’s woes worsened, and it filed for bankruptcy in July 2012. See *Patriot*

Bankruptcy May Leave Peabody Liable for Expense, Bloomberg News, July 10, 2012, <http://www.bloomberg.com/news/2012-07-10/patriot-bankruptcy-may-leave-peabody-liable-for-expense.html> (“[Patriot] is the biggest casualty so far of the slump in the U.S. coal industry, which has cut tens of millions of tons of production following a mild winter and after natural-gas prices dropped to their lowest in a decade.”). This trend may well continue beyond 2012, with Central Appalachia and its higher cost coal bearing the brunt of the loss in market share. See, e.g., Kris Maher, *Coal Strikes a Tough Vein over Costs, Natural Gas*, Wall St. J., Aug. 12, 2011, at B3 (quoting Alpha Resources’ CEO, Kevin Crutchfield, who explained that “Central Appalachia has been in a steady state of decline and probably will continue to decline for a while”).

These individual examples demonstrate the widespread impact of the natural gas revolution in this region. Industry reports cite that “utilities in the eastern US continue to face the most pressure to cut back on coal-fired capacity.” Thomas Wadewitz et al., *Railroads*, JP Morgan North America Equity Research, Apr. 17, 2012, at 4. This is at heart a simple matter of numbers – more coal plants are located in the eastern and midwest United States. *Id.* at 11. SNL Energy recently published a map of coal-fired power plants that it believes may be subject to displacement from natural gas. As shown in that map below, not only are the overwhelming majority of coal plants facing some risk of displacement from competition from natural gas located in the eastern United States, but the region is also home to a large percentage of the combined cycle gas turbine (“CCGT”) plants with which they compete.

Figure 1: SNL Energy – Coal Power Plants Subject to Displacement



SNL Energy, Coal to Gas Switching, at 10 (Sept. 2012). The competitive conditions imposed by this density of both resources will continue to have a great impact on the economics of coal power plants within the region going forward.

B. Higher Coal Production Costs in Eastern United States

At the same time as natural gas prices are falling and nationwide environmental costs related to coal-fired generation are increasing, the costs of producing coal in Appalachia are

increasing disproportionately due to new and heightened enforcement of existing environmental and safety regulations, driving up the cost of coal-fired electricity production relative to natural gas-fired production. Such increased production costs are due in part to stricter regulations and greater regulatory scrutiny on mining methods used in some Appalachian coal fields. “New federal rules restricting impacts to streams from mining in six Eastern states have put more pressure on thermal coal, which is often mined from the surface with explosives and earth-moving machines.” Kris Maher, *Coal Strikes a Tough Vein Over Costs, Natural Gas*, Wall St. J., Aug. 12, 2011, at B3 (discussing so-called “mountaintop removal” coal mining). Mining permits have also been placed under more scrutiny in recent years. See Dan Lowry, *As Layoffs Mount, Anger Boils Over in Appalachian Coal Country*, SNL Daily Coal Rep., June 25, 2012 (quoting Kentucky Coal Association President Bill Bissett discussing higher mining costs resulting from permit denials). Regardless of whether federal agencies issue fewer mining permits in Appalachian coal regions (reducing available supply), impose more stringent conditions and mitigation requirements on this sort of mining, or both, the result will be the same: increased costs and prices for coal that is already among the most expensive in the country. See *infra* Section IV.C.

An additional regulation with significant potential for increasing the cost of coal-fired generation in the eastern United States is the EPA’s Cross-State Air Pollution Rule (CSAPR), issued in 2011. CSAPR is more stringent than existing SO₂ and NO_x restrictions, and would require emissions reductions in 28 States, covering most of the eastern half of the United States. Experts have predicted that CSAPR would cause increased displacement of coal generation by other sources. See, e.g., PJM, *Coal Capacity at Risk for Retirement in PJM* (Aug. 26, 2012) (report concerning potential impacts of CASPR and MATS on coal-fired power generation by

regional transmission organization that covers much of the coal service territory of NS including IL, IN, KY, MD, NC, NJ, OH, PA, TN, VA, and WV); *id.* at 26-28; NERC, Potential Impacts of Future Environmental Regulations, at 116-18, 129-31 (Nov. 2011). On August 21, 2012, a panel of the U.S. Court of Appeals for the DC Circuit Court voted 2-1 to vacate CSAPR and remand the rule to the EPA for further proceedings. In October 2012, the EPA and nine states petitioned the full D.C. Circuit Court of Appeals to hear the case and reinstate CSAPR. *See* Petitions for Rehearing En Banc, No. 11-1302, *EME Homer City v. EPA et al.* (D.C. Cir. Oct. 5, 2012). Thus, the future application of CSAPR is uncertain. Whatever approach the EPA follows, it is likely to increase costs of coal-fired generation and lead to increased competition from natural gas in the eastern United States.

C. Cumulative Effects in Eastern United States

The effects of these regulatory and production hurdles account in part for the substantially higher cost of coal produced in the eastern United States versus coal from other regions. As demonstrated by the EIA data below, Central Appalachian (“CAPP”) coal is significantly more expensive on a short ton basis than coal from other regions of the United States.

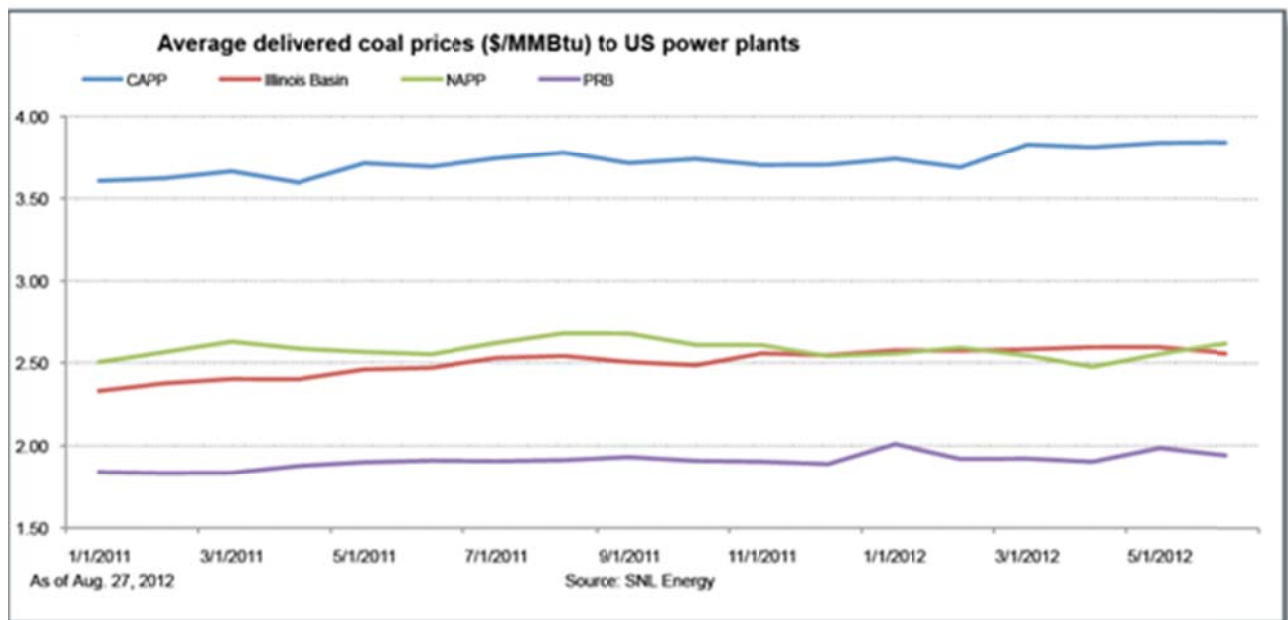
Figure 2: EIA Weekly Spot Prices

Average weekly coal commodity spot prices (dollars per short ton)			
Week Ended	Central Appalachia 12,500 Btu, 1.2 SO ₂	Illinois Basin 11,800 Btu, 5.0 SO ₂	Powder River Basin 8,800 Btu, 0.8 SO ₂
Oct. 12, 2012	\$65.95	\$47.90	\$10.25
Oct. 19, 2012	\$65.95	\$47.90	\$10.25
Oct. 26, 2012	\$65.95	\$47.90	\$10.25
Nov. 2, 2012	\$65.95	\$47.90	\$10.35
Nov. 9, 2012	\$65.95	\$47.90	\$10.35

EIA, Weekly Spot Prices, http://www.eia.gov/coal/news_markets/, last accessed Nov. 19, 2012.

As a result, the average delivered coal price to United States power plants for CAPP coal has been consistently at least \$1.00 MMBtu higher than Illinois Basin coal and \$1.50 MMBtu higher than PRB coal over the past two years.

Figure 3: SNL Energy – Average Delivered Coal Prices by Origin



SNL Energy, Coal to Gas Switching, at 5 (Sept. 2012). These differences are not explained by transportation costs, which are typically higher on a MMBtu basis for PRB coal, especially for power plants in the eastern United States.¹⁷

By comparison, in its 2012 Annual Energy Outlook (“AEO”), the EIA provided price forecasts under a number of different scenarios, and under all of them, the price of natural gas

¹⁷ See, e.g., Alpha Natural Resources, Form 8-K (June 28, 2010), available at <http://alnr.client.shareholder.com/secfiling.cfm?filingID=1301063-10-36&CIK=1301063> (indicating that “unlike other basins, transportation costs dwarf” commodity prices for PRB coal, and reporting that the average transportation cost for PRB coal was \$1.00 MMBtu, compared to \$0.47 MMBtu for coal from other basins).

remains below \$5.00 MMBtu (indexed to 2010) through most of the current decade. EIA, AEO 2012, at 91-92 (June 2012). Overall, the EIA's 2012 Coal Report, analyzing the actual data from 2011, found that production from Central Appalachia *decreased* in 2011 versus a still unimpressive 0.8% growth rate for coal overall. *Id.* tbl. 69 (Coal Production by Region and Type). The EIA projections for 2012 forward are equally pessimistic. *Id.* at 98 ("U.S. coal production [is forecast to] *decline[] for four years* thereafter as a result of low natural gas prices, rising coal prices, lack of growth in electricity demand, and increasing generation from renewables.") (emphasis added).

Given these relatively high costs and production projections, industry experts and participants agree that natural gas-for-coal switching will continue in the eastern United States even if changing conditions lessen its impact in other parts of the country. SNL Energy reported that "it is widely known that much of the Eastern fleet is at a cost disadvantage compared to the average CCGT plant." SNL Energy, Coal to Gas Switching, at 8 (Sept. 2012). SNL found the calculated floor on natural gas prices for regional coal displacement to be \$5.08 MMBtu for CAPP coal, compared to \$3.80 MMBtu for Illinois Basin and \$2.65 MMBtu for PRB coal. Jesse Gilbert & Steve Piper, *Stage set for significant coal-to-gas switching in remainder of 2012*, UAE Weekly Energy Brief, Apr. 29, 2012 ("[T]he data points toward continued significant potential for switching for Eastern U.S. coal."). Jack Fusco, Chief Executive Officer of Calpine Corporation, highlighted similar calculations this month and predicted the higher cost structure for coal-fired generation in the eastern United States will continue to lead to greater coal-to-gas switching in the region than elsewhere in the country: "In the first half of this year, when gas was level at \$3, we saw coal-to-gas switching everywhere across our fleet, including in Texas. At the current gas mark for next year, we expect we'll see some coal-to-gas switching in the East, but

probably none in Texas.” Calpine Corporation, Q3 2012 Earnings Call, Nov. 6, 2012, available at <http://seekingalpha.com/article/983901-calpine-management-discusses-q3-2012-results-earnings-call-transcript>. Therefore, the same competitive forces that are challenging coal-fired production on a national level seem certain to continue to impact utilities in the eastern United States going forward.

V. Conclusion

The unanticipated and unprecedented transformation of the utility generation market over the past few years has recalibrated the balance between coal and natural gas in the electricity market, especially in the eastern United States. The abundant supply of cheap natural gas, along with the increased pressure on coal power plants imposed by recent environmental regulations, have upset historical trends; utility companies for which natural gas was once an afterthought are now dispatching their gas-fired resources ahead of even efficient coal-fired power plants. As a result, large utility companies making decisions about when and how to run their coal-fired resources can no longer “assume that coal is going to be lower than natural gas.” Instead, as their executives and financial reports indicate, they are assessing the cost of production at each plant in comparison to the cost of dispatching or purchasing power from another resource. Under such conditions, coal transportation rates to certain coal-fired power plants, those which are not always “in the money” depending on the price of natural gas or other competitive options, are constrained by those competitive choices of which the utilities can, and clearly are, taking advantage. The AAR has presented the Board with a body of simple, readily-available evidence from which a determination of the impact, if any, of indirect competition on specific coal power plants can be evaluated on a case-by-case basis. NS submits that current conditions necessitate that the Board take stock of competition as it is actually taking place in the market

and consider such evidence when assessing market dominance in rate cases brought by utility companies concerning coal transportation.

Respectfully submitted,

A handwritten signature in blue ink, appearing to read "James A. Hixon", is written over a horizontal line.

James A. Hixon
John M. Scheib
David L. Coleman
Garrett D. Urban
Norfolk Southern Corporation
Three Commercial Place
Norfolk, VA 23510

*Counsel for Norfolk Southern
Railway Company*

Dated: November 26, 2012

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1

May 29, 2012

Even in Coal Country, the Fight for an Industry

By ERIC LIPTON

LOUISA, Ky. — For generations, coal has been king in this Appalachian town. It provided heat, light and jobs for the hundreds of people who worked in the nearby coal mines and the smoke-coughing Big Sandy power plant that burned their black bounty.

But now, coal is in a corner. Across the United States, the industry is under siege, threatened by new regulations from Washington, environmentalists fortified by money from Michael R. Bloomberg, the billionaire mayor of New York City, and natural gas companies intent on capturing much of the nation's energy market.

So when the operator of the Big Sandy plant announced last year that it would be switching from coal to cleaner, cheaper natural gas, people here took it as the worst betrayal imaginable.

“Have you lost your mind?” State Representative Rocky Adkins, a Democrat and one of Kentucky's most powerful politicians, thundered at Michael G. Morris, the chairman of the plant's operator, American Electric Power, during an encounter last summer. “You cannot wave the white flag and let the environmentalists and regulators declare victory here in the heart of coal country.”

Coal and electric utilities, long allied, are beginning to split. More than 100 of the 500 or so coal-burning power plants in the United States are expected to be shut down in the next few years. While coal still provides about a third of the nation's power, just four years ago it was providing nearly half.

The decline is largely because new pollution rules have made coal plants more costly, while a surge in production of natural gas through the process of hydraulic fracturing, known as fracking, has sent gas prices plummeting. Together, the economics of coal have been

transformed after a century of dominance in Washington, state capitals and the board rooms of electric utilities.

“The math screams at you to do gas,” said Mr. Morris, whose company is the nation’s largest consumer of coal.

Environmental groups, after years of targeting coal plants as leading sources of air pollution, have moved in for the kill. “We never thought we would get to a place where coal plants are falling so fast,” said Bruce Nilles, the director of the Sierra Club’s Beyond Coal initiative. It has been aided by \$50 million from Mr. Bloomberg, who views the campaign as part of a public health effort, and \$26 million from an odd bedfellow: the top official of a natural gas company.

The environmentalists figure that if they can shut down a third of the nation’s coal burning plants by 2020, emissions of greenhouse gases in the United States could be cut at least as much as they would have under a landmark 2009 climate bill that died in Congress.

But the coal industry is mustering all the weapons it can: lobbying, legislation, litigation and a multimillion-dollar advertising campaign trumpeting the benefits of “clean coal.” The fight has even become an issue in the presidential campaign, with the industry blaming President Obama and the Environmental Protection Agency for the onslaught, and Mitt Romney, the presumptive Republican nominee, hinting that he would roll back some of the rules.

Here in Kentucky, the intervention by Mr. Adkins and other coal industry advocates has saved coal at Big Sandy, at least temporarily. American Electric Power, which is based in Columbus, Ohio, is proposing a \$1 billion retrofit to allow the plant to continue burning coal and has asked Kentucky regulators to approve a 30 percent increase in electricity rates to pay for the work.

But that request, which will come up for a vote by the state’s utility commission within the next week, has inspired resistance from some residents, large industrial companies that consume much of Kentucky’s electricity and even the state attorney general’s office.

Pressured on the domestic front, some giant American coal producers, like Arch Coal and Peabody Energy, are shifting their attention to markets overseas, where coal-fired power plants are being built faster than they are being abandoned in the United States.

Even if Big Sandy continues to eat up 90 rail cars of coal a day, the industry’s decline is evident

here. Sales to Midwestern power plants have slumped, as has the market price of coal, dropping so suddenly that many local mines are cutting back hours or closing. A warm winter, decreasing demand, only made matters worse.

“I call it the imperfect storm,” Mr. Adkins said. “And it is breaking the back of our local economy.”

A Coordinated Effort

The anger toward Washington is palpable in this impoverished corner of Eastern Kentucky, where miners display bumper stickers or license plates on their pickup trucks with slogans like “Coal Keeps the Lights On” or “If Obama Is the Answer, How Stupid Was the Question?”

It is hard to find anyone here who does not feel affected by the fate of Big Sandy. Just as the smokestack at the plant towers over the countryside, Big Sandy dominates much of life here.

Danny Sartin, 61, a barrel-chested heavy equipment operator at the plant, said his father, grandfathers and uncles all worked in local mines that feed Big Sandy. “Coal and the coal mining industry, it’s all we have ever known,” Mr. Sartin said.

Some of that coal comes from the Licking River mine, about 50 miles south of Big Sandy, where miners rip apart hillsides to reach vast seams just below the surface.

Chris Lacy, 41, an executive at Licking River Resources Inc., said layoffs among his 350 miners — in Magoffin County, where unemployment is already 17.5 percent — are inevitable if the coal furnaces at Big Sandy go cold. Even the garden supply company that Mr. Lacy’s father-in-law owns and where his two sons work indirectly relies on Big Sandy, because mines are required to plant grass over the scarred earth they leave behind. “It is the ripple effect that comes right through us,” Mr. Lacy said.

Channeling the animosity toward Washington and fears about their livelihoods, coal producers, union leaders, landowners and railroads came together to pressure American Electric Power to back down on its plan to close the coal furnaces at Big Sandy. They have leaned on county judges, state legislators and other politicians to attempt to silence public criticism of the 30 percent electricity rate increase and to pressure the Kentucky Public Service Commission to approve the retrofit project.

Saving coal, they argued, justified the rate increase, which would cost the average residential customer about \$472 a year in addition to the typical \$1,580 annual bill today.

“I will grant you it is going to cost a lot of money to retrofit that plant,” said Nick Carter, the president of a company that represents landowners whose properties hold billions of tons of coal reserves. “But how many teachers will be laid off and how many churches will have to close if Big Sandy stops burning coal?”

At Dee’s Drive Inn Restaurant, a fixture on Main Street in Louisa, the patrons are split.

Fred Klinebriel, 58, a disabled former steelworker, said his father was a mine worker and his brother a trucker who moved coal. But if keeping coal means an even bigger electric bill, he is not sure it is worth it. “I am up against the wall right now as it is,” he said. “I guess you are damned if you do and damned if you don’t — or at least we are here in coal country.”

Environmental Issues

What went largely unspoken in the dozens of pages of e-mails, letters and other pitches these players have churned out in the fight to keep the plant open were the perils of coal, which extend far beyond mine accidents and black lung disease.

The Big Sandy plant spews tens of thousands of tons of pollutants each year into the region’s air, including sulfur dioxide and smaller amounts of mercury, which can cause health problems like respiratory illnesses and possibly developmental disabilities among children. Many of these pollutants would be significantly reduced with the retrofit, but the plant would continue to be a major source of carbon dioxide, which is blamed for global warming.

Big Sandy also maintains a sprawling coal ash pit near the plant, created to store waste ash after the coal is burned, that the E.P.A. recently listed as one of 45 “high hazard” pits nationwide. That means it “will probably cause loss of human life,” the E.P.A. says, if a serious accident occurs. In Tennessee in 2008, a billion gallons of slurry from a coal ash pit washed out area homes and streams, though no deaths resulted.

Meanwhile, federal regulators have accused the owners of Licking River of dumping debris, known as spoil, from another nearby mine into a local valley, harming wildlife and an intermittent local stream.

Mr. Lacy, the Licking River executive, says such concerns are overblown. Instead, he talks of a conspiracy by environmentalists and the Obama administration to destroy the way of life here in Kentucky.

“I at least have to give them some credit,” he said. “It has been well played on their part, very methodical, step by step.”

Some of the regulations the industry finds objectionable, though, had their origins in a Republican administration. In 1990, President George Bush proposed and Congress approved sweeping revisions to the Clean Air Act, authorizing the E.P.A. to regulate emissions of mercury, arsenic and other toxic airborne chemicals. The agency determined in 2000 that it had the power to limit such emissions from power plants, but a weak rule issued under the second Bush administration was successfully challenged in court by environmental advocates.

The Obama administration, acting under court order, issued new standards in December that would require more emissions reductions by all but the top-performing plants. Gina McCarthy, the director of the Office of Air and Radiation at the E.P.A., said that accusations of collusion between the agency and environmental advocates were unfounded.

“Coal will continue to be a large part of electric generation in this country for a long time,” Ms. McCarthy said in an interview. “I just hope it is cleaner.”

Mr. Lacy is hardly convinced. As he drove through the Licking River mine during a shift change one recent afternoon, his face reddened.

“If they keep this up, the people who live here are going to have to move somewhere else, like during the Depression,” he said. “This place is suffering in a bad way.”

Unlikely Allies

Tacked up on the wall in a cramped office in Columbus, Ohio, that serves as the Midwest headquarters for the Sierra Club is a map of the United States with the headline “Coal Plants Under Target.” Dozens of color-coded pins form a giant U shape — from Minnesota, south to Missouri, east to Kentucky and then up to Ohio — with each marking a plant that the Sierra Club is determined to shut down.

For years, the group filed lawsuits to try to force utilities or federal regulators to comply with pollution-control laws and organized public opinion campaigns to try to block the construction of plants. But the change in the energy marketplace has given the environmentalists an extraordinary new weapon: the pocketbooks of consumers.

“The coal industry used to be able to get away with murder, here in Ohio and throughout Appalachia,” said Nachy Kanfer, 27, a Sierra Club organizer. “Not anymore.”

In late April, Mr. Kanfer and other Sierra Club staff members traveled to Kentucky to testify before the Kentucky Public Service Commission. They argued that American Electric Power should not be allowed to retrofit Big Sandy — an argument they are making in many states — because there are less expensive alternatives to deliver power.

Elsewhere, the Sierra Club and other environmental groups are also pressing local officials in metropolitan areas to help shut down coal-burning power plants. In Chicago, for example, Mayor Rahm Emanuel recently announced that the city’s last two coal-fired plants would close in 2014, four years earlier than expected.

One of the most important early allies in this fight was Aubrey K. McClendon, the chief executive of Chesapeake Energy, who donated \$26 million starting in 2007 to help the Sierra Club with its campaign.

The company also donated millions of dollars more to the American Lung Association, which used the money, in part, to run “Fighting for Air” television commercials. Some of the most recent ads in the campaign feature a baby coughing, wheezing and then crying while sitting outside a coal-fired power plant.

The Sierra Club came under attack from other environmental activists for accepting money from Mr. McClendon, whose company has a financial interest in killing off its competition but burns a fossil fuel itself. Mr. Nilles, the director of Beyond Coal, now views it as a mistake. “We would not do it again,” he said.

Other deep-pocketed donors have stepped in, including Mr. Bloomberg, whose intervention has infuriated Kentucky officials like Mr. Adkins, the legislator.

“Mayor Bloomberg should stay in that high-rise condo or his mansions,” Mr. Adkins said, “and

eat his caviar while we keep his lights on in New York City.”

Big Coal has hardly conceded defeat in this multifront war.

The industry has increased political campaign contributions in the last four years to historic levels, with 80 percent of those donations going to Republicans, according to the Center for Responsive Politics. Companies like Arch Coal, which used to spend only about \$100,000 a year on lobbyists in Washington, invested \$5.7 million to push its case during the first three years of the Obama administration.

And even as American Electric Power plans to close 5 of its 21 coal-burning plants and rely much more on natural gas, it still intends to retrofit 12 plants. That means it will be burning coal for years to come. A rise in natural gas prices could also slow the decline of coal as a power source. So the company has joined with old allies in Washington to try to delay the new rules and block any future ones.

The industry and its supporters have also gone to court, filing lawsuits challenging E.P.A. rules that limit pollution from coal-burning plants from crossing state lines and the mountaintop mining rules that are holding up new permits in Kentucky and West Virginia — legal fights that the industry has had some success with so far.

But the regional agency that coordinates electric power delivery in the mid-Atlantic and the Midwest cannot wait for the battles to be resolved. This month, it auctioned off the rights for utility companies to supply electricity that will be needed to make up for what is lost through coal plant retirements. Most of the new power is fueled by natural gas.

“It’s an unprecedented transition,” said Michael J. Kormos, senior vice president for operations at PJM Interconnection, the regional group that coordinates power delivery for 60 million people in 13 states. “But whatever happens, we have to make sure we keep the lights on.”

John M. Broder contributed reporting from Washington.

This article has been revised to reflect the following correction:

Correction: May 31, 2012

An article on Wednesday about the use of natural gas instead of coal as fuel for power plants misstated the amount of coal burned each day at the Big Sandy plant in Kentucky. It is about 90 rail carloads, not nine.

2

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Railroads Run Out of Steam at the Coal Face

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By LIAM DENNING

Even in the age of the "new iPad," there is a lot of money to be made just hauling around rocks—specifically, coal.

Railroads are still beholden to coal, which is tailor-made for the business. It is heavy and shipped in large volumes between the same set of fixed points—mine, power plant, foundry, port—over and over. Alternative means of transport are limited. That makes for pricing power, big revenues and high margins. Although it isn't reported clearly, railroads derive an estimated 40% to 50% of operating profit from hauling around coal, says David Vernon of Bernstein Research.

Problem is, the U.S. is using less coal. On a 12-month rolling basis, coal consumption in November was 10% below its July 2008 peak. And the trend is down, especially as mild winter weather has curtailed already weak demand for electricity. Power generation accounts for more than 90% of coal use.

Even more important is the impact of the revolution in U.S. natural gas. With gas now so cheap, generators are opting when possible to burn it instead of coal. Research firm ISI Group estimates that demand from utilities may drop by as much as 50 million tons this year, equivalent to 5% of consumption.

So even though U.S. rail traffic overall is down only 1.4% so far this year, according to the Association of American Railroads, coal carloads are down 7.6%. The stock prices of **CSX Corp.**, **CSX +1.76%**, **Norfolk Southern Corp.**, **NSC +1.26%** and **Union Pacific Corp.**, **UNP +1.62%** all have trailed the transportation sector and, even more so, the S&P 500 so far this year.

CSX and Norfolk have been hit hard as their Eastern networks are exposed to Appalachian coal, accounting for more than 30% of revenue. Early this past week, their forward price/earnings multiples hit about 11, representing a 10% discount to the S&P 500, the biggest gap since the autumn of 2009.

That makes the stocks look cheap and, indeed, both rose later in the week after CSX's chief financial officer told a conference that, despite coal shipments diving by up to 30% during this quarter, his company should earn a record profit. He cited offsets from increased intermodal—carrying containers that also go on trucks and ships—and merchandise traffic.

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This is encouraging, but coal's decline isn't merely the side-effect of a mild winter. Chronic oversupply in the natural-gas market, limiting price increases, will make it a formidable competitor in the utilities sector for years to come. Meanwhile, tighter environmental regulations on coal-fired power plants will force some to close. Bernstein estimates a net 15% of the current fleet will close by 2015, equivalent to 106 million tons of annual coal demand, or 10%.

Meanwhile, another offset, coal exports, may weaken. Chinese demand for coal, especially for making steel, has helped keep the coal cars rolling. But this was due to China's construction binge as part of government-stimulus efforts and floods in Australia limiting competing coal cargoes. These tailwinds can't be relied on in the future.

Longer term, the desire for more fuel-efficient modes of transport provides support for railroads as an investment—hence the purchase of Burlington Northern Santa Fe [Fe](#) [BNS +0.92%](#) by [Berkshire Hathaway](#), [BRKB +1.05%](#) announced in 2009. But with the bedrock of their coal business being undermined, anyone buying these stocks now will need to take Warren Buffett's approach and settle in for the long haul.

—Liam Denning

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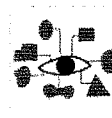
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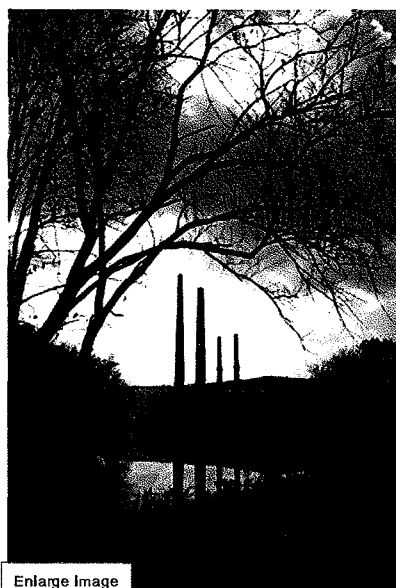
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By REBECCA SMITH

In its heyday, the giant W.H. Sammis power station was a workhorse, cranking out electricity around the clock. But [FirstEnergy Corp.](#) (FE -0.32%) now plans to idle the coal-fired power plant on the Ohio River and run it only when there is exceptional need for electricity.

Sammis is one of a growing number of coal-fired plants that were built to run 24 hours a day, seven days a week, but now may run only occasionally because of soft demand for electricity and competition from gas-fired plants that are cheaper to run and cleaner to operate.



Enlarge Image

KRT/Newscom

The W.H. Sammis coal-burning power plant.

Coal has been losing ground to natural gas ever since a boost in shale-gas production sent the price of natural gas tumbling four years ago. But now the natural-gas price advantage is beginning to affect the coal units that seemed most protected from the shift. Many of these plants have the latest environmental upgrades and are often close to coal deposits.

The reason: With natural gas priced below \$3 per million British thermal units, down from about \$8 in 2008, many gas-fueled plants can make electricity for about two cents a kilowatt hour, less than half what it costs to run many coal units, said Julien Demoulin-Smith, director of utilities research at UBS Securities LLC in New York.

"This marks another iteration of the way in which natural gas is displacing coal," said Mr. Demoulin-Smith. He said he expects the trend to become more pronounced in coming months as companies seek ways to cut their operating costs, especially those selling power into deregulated markets in the Northeast, Midwest, California and Texas, where power prices are very low

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because there is no pricing floor.

FirstEnergy, based in Akron, Ohio, spent more than \$1.8 billion putting pollution controls on the seven-unit Sammis plant in Stratton, its largest generating station in Ohio, starting the work before the 2008 economic downturn.

Even so, "if things don't pick up and electricity (profit) margins don't improve, the Sammis units won't run anymore," Mark Durbin, a First Energy spokesman, said of the plant, whose units were built between 1959 and 1971.

Another owner of generating plants, Dallas-based Luminant, recently announced plans to put two big, coal-fired generating units at its Monticello power plant in northeast Texas into semiretirement. A third, newer unit will continue running.

Last year, Luminant threatened to shut down the plant and its adjacent mining operation, blaming looming federal emissions restrictions. The rules were recently struck down by the courts.

Luminant, a unit of Energy Future Holdings Corp. of Dallas, says the change this year is prompted by market forces.

That is because natural-gas plants set market prices in Texas, and their costs are so low that they can often sell power for less than what it costs to run a coal plant. One reason Luminant's costs are higher is because of coal-handling expenses and the higher number of employees it takes to run a coal plant compared with a gas-fired plant.

"It's all about low wholesale prices," said Luminant spokesman Allan Koenig. Luminant is lobbying utility regulators for creation of a subsidy for generators that would reward them for keeping coal-based generating plants standing by to create electricity if needed.

Historically, units situated near mines—like those at Monticello, which burn the low-grade coal known as lignite—didn't need special assistance. They were able to make electricity more cheaply than any other kind of fossil-fuel plant. But proximity to even the cheapest coal is no longer a decisive advantage.

PPL Corp., [PPL -0.53%](#) of Allentown, Pa., is considering putting some of its coal units into formal part-time operating status, too, said George Lewis, a company spokesman. Several PPL units in the Midwest and Northeast were sidelined for extended periods this past spring because there weren't buyers for their power. The company expects power prices to remain low for the next couple of years, potentially idling units "for even longer periods," he said.

Ohio-based [American Electric Power Co.](#) [AEP +0.10%](#) started down this path a couple years ago, changing the operating status of 10 generating plants in Ohio, Indiana, West Virginia and Virginia. Today, it keeps a skeleton crew at each location and brings in more workers when it wants to bring some of the coal units back to life, something that requires about four days notice.

AEP's annual coal burn has dropped from approximately 75 million tons before 2008 to a projected 55 million tons in 2012. The multistate utility's natural-gas use, over that same period, has doubled, to about 200 billion cubic feet.

Write to Rebecca Smith at rebecca.smith@wsj.com

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July 30, 2012

Why Coal Plants Retire: Power Market Fundamentals as of 2012

By Susan F. Tiemey, PhD

Power companies in the U.S. have announced a growing number of retirements of coal-fired power plants over the past 12 to 14 months. While not unexpected, recent announcements have sparked debate over the causes of these business decisions, with some pointing to regulations issued by the U.S. Environmental Protection Agency (EPA) as the primary reason.

Putting aside the political context of the current debate, a closer examination of the facts reveals that the recent retirement announcements are part of a longer-term trend that has been affecting both existing coal plants and many proposals to build new ones. The sharp decline in natural gas prices, the rising cost of coal, and reduced demand for electricity are all contributing factors in the decisions to retire some of the country's oldest coal-fired generating units. These trends started well before the EPA issued its new air pollution rules.

In general, the owner of a coal-fired power plant (or of any generating facility, for that matter) may decide to retire the plant when the revenues produced by selling power and capacity are no longer covering the cost of its operations. Though sometimes these decisions are complex, they essentially can resemble the basic choices that households face, for example, when they have to decide whether making one more repair on an old car is worth it; often, making the repair is more expensive and risky than the decision to trade in that car and buy a new one with better mileage and other features that the old car lacks.

These plant-retirement decisions thus turn on these economic fundamentals: Can the plant produce power at electricity prices that allow the owner to cover its operating and investment costs, including the ability to earn a reasonable return from the production and sale of electricity? It is these other considerations, beyond the EPA's clean air rules, that have been influencing recent coal plant retirement decisions.

Electricity Market Dynamics

In today's power industry, the profitability of many coal plants depends substantially on the difference in price between coal and natural gas. In competitive power markets like those in the Midwest, Mid-Atlantic, and Northeast, and even in more traditional power regions such as the Southeast, falling natural gas prices lead to lower revenues for coal plants by causing wholesale electricity prices to decline. Rising coal prices can further narrow the margins of coal plant operators. In the past year, coal plants have been facing a perfect storm of falling natural gas prices, a continued trend of high coal prices, and weak demand for electricity (Figure 1).

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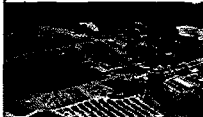
 

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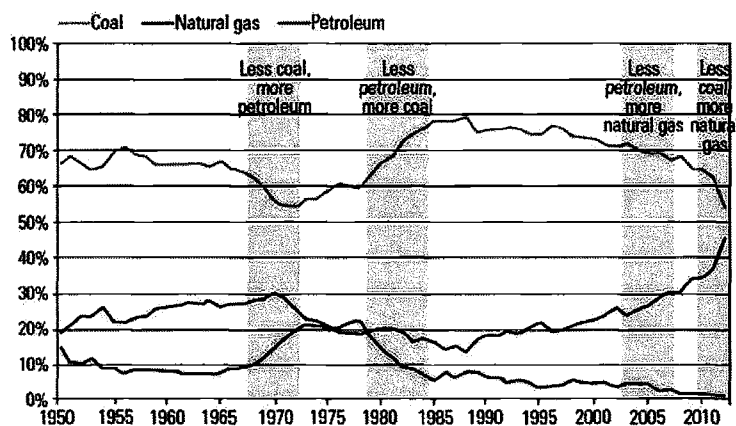


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Low oil prices during 1960's combined with smog concerns, spur new additions to petroleum-fired capacity.

Rapidly rising oil prices lead many generators to switch oil-fired peaking capacity to natural gas.

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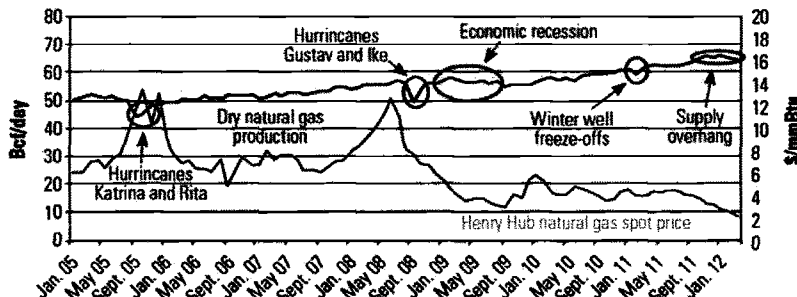
Oil price shocks during 1970s lead to increased utilization of coal-fired capacity for baseload generation.

Historically low natural gas prices lead to increased utilization of combined cycle plants at expense of coal units.

Notes: Shares are calculated using generation supplied by all sectors. Data for 2012 include January through April. Start and end years for the grey boxes are approximate. A very small percentage (generally less than 0.5%) of fossil-fired generation is from other gases, not shown.

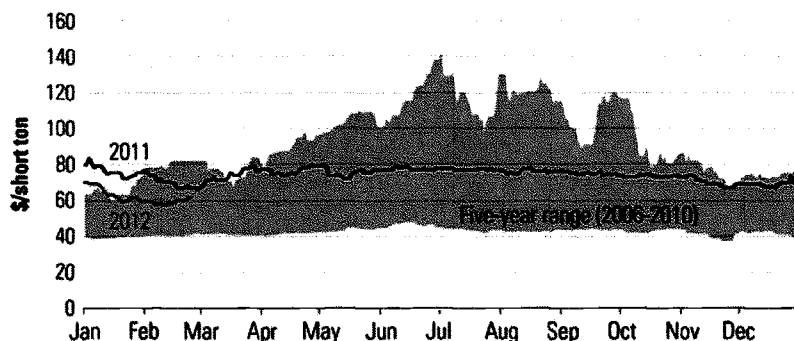
1. The fuels used to produce electricity are responding to market conditions—rising coal prices and dropping natural gas prices. Source: EIA

Natural gas prices have fallen to record lows, reducing the wholesale price of electricity in most of the country's power markets. Natural gas prices fell from \$4.37/MMBtu in 2010 to \$3.98/MMBtu in 2011, to under \$2.00 in May 2012. The average NYMEX spot price was \$2.87 in mid-July. The result has been a significant drop in wholesale power prices. Wholesale electricity prices have dropped more than 50% on average since 2008, and about 10% during the fourth quarter of 2011. The record low natural gas prices are attributed to strong domestic production, robust storage levels, and new pipeline projects that have allowed additional supplies to get natural gas to markets (Figure 2).



2. U.S. production of natural gas has been steadily increasing since late 2005 but has lately leveled off. The red ovals on the chart illustrate periods when natural gas production leveled off during a period of falling natural gas spot market prices. The first was during the economic recession. The latest began in the fourth quarter 2011 and continued through the first quarter of 2012. Natural gas prices continued to fall through the first half of 2012. Source: EIA

At the same time, coal prices have remained relatively high: According to the U.S. Energy Information Administration (EIA), "Delivered coal prices to the electric power sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (5.8 percent increase from 2010)." The price of coal during early 2012 dropped sharply due to a warm winter and low natural gas prices (Figure 3).



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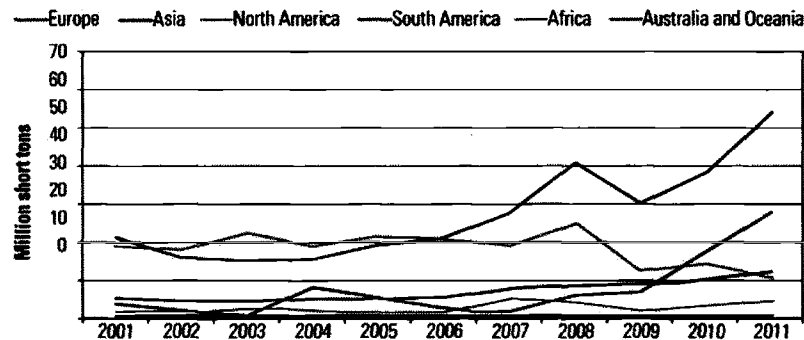
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3. Central Appalachian NYMEX coal futures prices, \$/short ton. Source: EIA

Coal prices have pushed upward in part because exports have offset a drop in domestic coal consumption. The Appalachian region, in particular, saw a large increase in exports last year, driven by demand for metallurgical coal used in steelmaking. U.S. coal exports increased 31% in 2011, the highest level since 1991 (Figure 4).

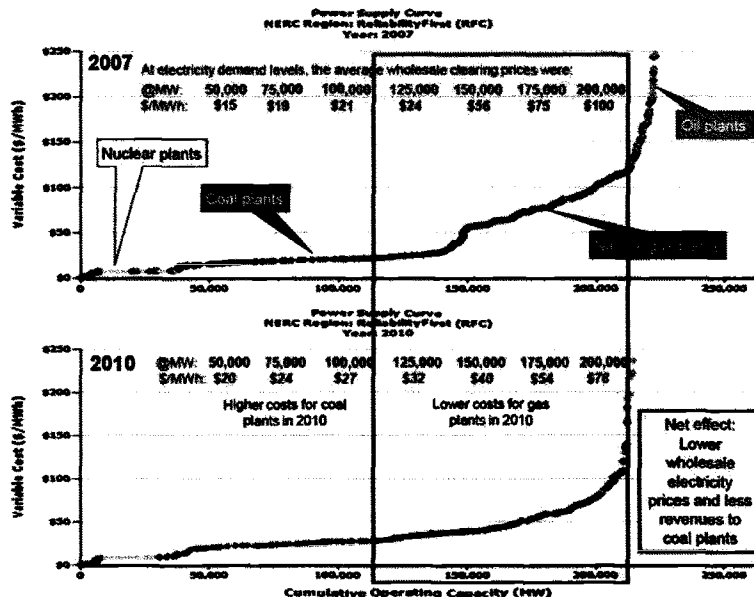


4. Coal exports to European and Asian markets represented 76% of total U.S. coal exports in 2011. In 2011, coal exports were up 31%, largely to rising exports to Europe and Asia. Source: EIA

The surge in exports was driven in part by reduced production in other parts of the world. Flooding last year disrupted coal mining in Australia, the world's largest coal exporter, contributing to increased U.S. coal trade with India, Japan, and South Korea. Coal exports are expected to remain strong in response to global energy demand. Arch Coal, for example, announced in a news release of February 10, 2012 that it had made several investments in 2011 to bolster its U.S. export capabilities.

The tighter price differentials between natural gas and coal in recent years have squeezed the financial performance of many coal plants, especially the older and less efficient ones. To illustrate, the power supply curve in the figure below indicates that in the PJM region (shown here as the RFC (ReliabilityFirst) region), coal-fired power plants dispatched at higher prices in 2010 compared to 2007, with the reverse true for natural gas-fired power plants.

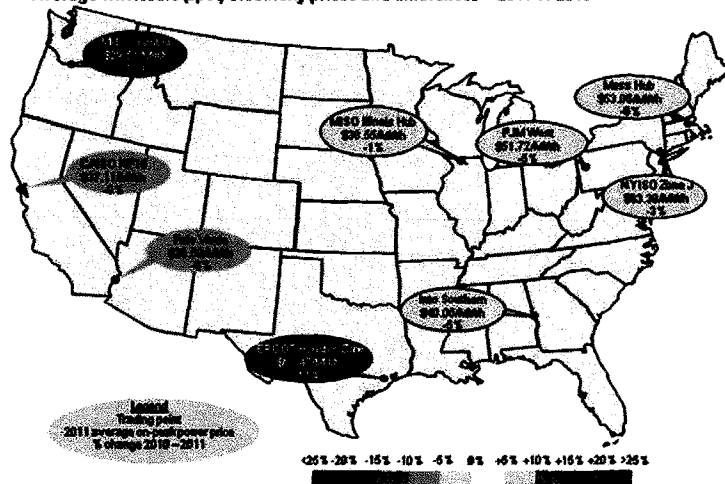
In this regional power market, the revenues for plants reflect the selling price of the last plant dispatched to meet loads. So, for example, a coal plant dispatched at a 125,000-MW level of demand sold power at \$24/MWh in 2007. At a higher demand level (say, 150,000 MW) that same year, the clearing price would be \$56/MWh, set by the dispatch of a natural gas plant. In that high-demand hour, the referenced coal plant would receive revenues of \$32/MWh (reflecting the \$56/MWh clearing price, less the coal plant's own production cost, including fuel, of \$24/MWh). By contrast, in 2010, the coal plant dispatching at a 125,000-MW demand level sold power for \$32/MWh, while the gas plant dispatched at a 150,000-MW load level was selling at \$40/MWh. In 2010, therefore, the referenced coal plant would receive net revenues of \$8/MWh in that high-demand hour (Figure 5).



5. Dispatching is largely determined by the plant owner's fuel cost. Source: Data from SNL Financial for 2007 and 2010 for the Reliability First Corporation region
[END ART]

Across the course of a year (as in 2010 and 2011), these much tighter gas-coal price differentials put significant price pressure on the least efficient coal plants. Net revenues were down in the hours they operated. And in many cases, system operators were dispatching more gas-fired power plants ahead of these less-efficient coal plants. The map in Figure 6 shows that with the exception of the ERCOT Texas market, average wholesale electricity prices were lower in 2011 than 2010.

Average wholesale (spot) electricity prices and differences —2011 vs 2010



6. Wholesale electricity prices dropped in 2011 across much of the U.S. due to lower natural gas prices. Source: EIA

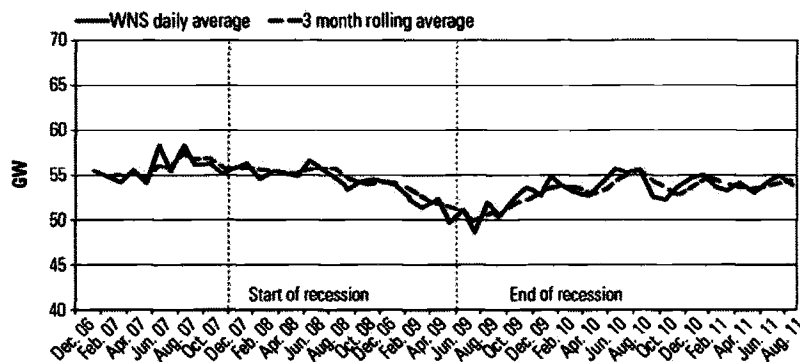
Several companies that have traditionally relied on coal for a substantial portion of their generation are using more natural gas. In its Q1 2012 earnings call (Apr. 20, 2012), AEP's executives reported that the company's natural gas consumption had increased 62% year over year, and that with the exception of one plant, its gas-fired combined cycles in the eastern part of its system were operating at an 85% capacity factor. In an interview in National Review ("War Over Natural Gas About to Escalate," May 3, 2012), AEP's CEO said that the company increased its overall "natural-gas capacity by 24 percent last year, and it expects to increase that by another 14 percent this year. . . . At the peak of 2007 and 2008, we were taking [and burning] about 80 million tons of coal a year. . . . Today, that's probably down to the order of 55 million tons of coal a year."

Similarly, Southern Co. executives recently reported on their Q1 2012 earnings call (Apr. 25, 2012) that in 2007, the company's electricity production was 16% natural gas and 70% coal. They now expect that the mix for 2012 will be 47% natural gas and only 35% coal. Its natural gas combined cycle plants have been operating at a 70% capacity factor, and the company estimates that its purchases of natural gas made up 2% of total gas consumption in the U.S.

These changing natural gas and coal prices have contributed to coal-fired electricity generation dropping by 13% from 2007 through 2011, while gas-fired power production increased by 13% in the same period, according to the EIA's Short-Term Energy Outlook, released February 2012 (Table 25).

Lower Demand for Electricity

On top of the economic pressures brought by lower natural gas prices, electricity demand has been muted due to the sluggish economy, increased competition from demand-side resources, and the mild winter weather. For operators of the least-efficient coal plants, in particular, these factors are further aggravating their financial situation (Figure 7).



7. This graph of weather non-sensitive load (the estimated peak load after removing the weather effects from actual peak load) in the Midwest (MISO) region indicates the underlying trends in demand from economic and demographic factors. Source: Midwest ISO, "MISO 2011 Summer Assessment Report: Information Delivery and Market Analysis," Oct. 19, 2011

Low demand for electricity moderates electricity prices by reducing the amount of time a relatively inefficient coal plant might otherwise be called upon to operate. In 2009, electricity consumption by industrial customers was at its lowest point in 10 years, according to FERC's "Winter 2011-12 Energy Market Assessment," released Oct. 20, 2011.

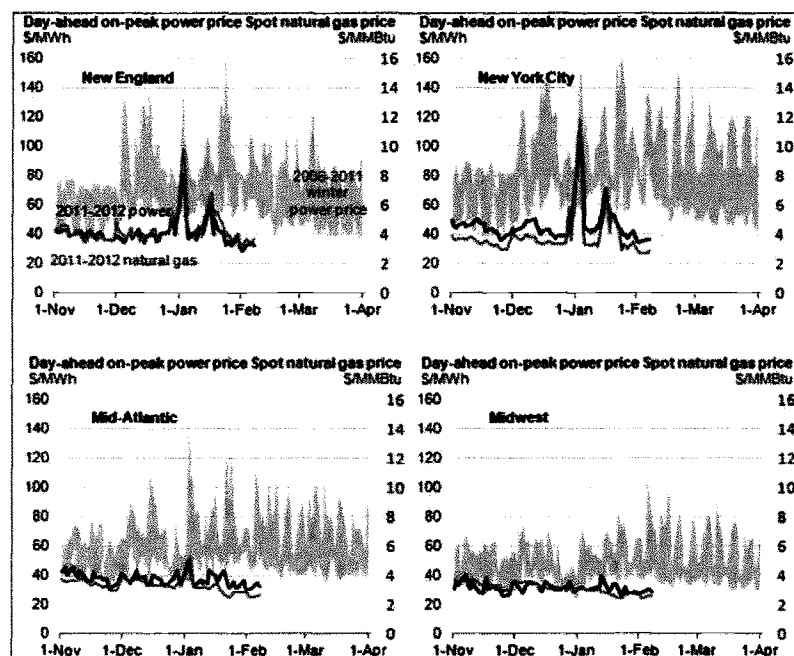
Although consumption has increased since then, it still remains below the levels prior to the economic collapse in 2008. As shown in Figure 7, excerpted from an assessment prepared by the Midwest ISO (MISO), electric loads (demand) in the heavily industrial Midwest power region declined in 2008 to mid-2009, followed by a gradual recovery since then.

Reduced demand for electricity has led companies to cancel some new power projects and idle existing plants. In an extreme case, Great River Energy mothballed a recently constructed coal-fired power plant in North Dakota. The plant was fully equipped with modern pollution control systems, but the owner has opted not to run the facility because of low demand for electricity and low power prices.

Energy efficiency and other demand-side resources have also played a role in moderating electricity prices. In PJM, the nation's largest energy market, demand response and energy efficiency contribute a growing share of new capacity in the market's forward capacity auction. Demand response, energy efficiency, and renewable resources made up about 10% of the resources clearing PJM's 2014–2015 capacity auction, according to a May 13, 2011, news release ("PJM Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction"). These resources were offered into—and accepted by—the market at prices lower than other competing generating resources that did not clear in the auction. Such resources contribute to the economic pressure on existing generating resources.

Although recent summer periods have been hotter than usual (notably in Texas), based on Federal Energy Regulatory Commission (FERC) data for cooling degree and heating degree days, the U.S. and Canada experienced one of the warmest winters on record, reducing energy demand and exacerbating the financial conditions of many generators. The two-month period from December to January was the fourth-warmest on record, according to a National Oceanic and Atmospheric Administration, Feb. 7, 2012, press release ("January 2012 the fourth warmest for the contiguous United States").

Minnesota experienced record warm temperatures for the winter period, with an average temperature 10.1 degrees F above average, according to FERC data. A total of 22 states from Montana to Maine had December to January temperatures ranking among their 10 warmest. Lower temperatures have contributed to lower natural gas demand, further dampening natural gas prices. Lower temperatures have also reduced the demand for electricity. The charts in Figure 8, published by the EIA on Feb. 15, 2012, illustrate the unusually low winter power prices experienced from November through the first week in February in the Northeast and Midwest, resulting from the warm weather.



8. Warm weather, low natural gas prices hold down winter power prices in the Northeast and Midwest. Source: EIA

Tennessee Valley Authority (TVA), the nation's biggest government-owned utility, attributed a 14.8% reduction in residential electricity consumption to the mild winter, according to "Mild winter pushes Tennessee Valley Authority in the red," published by *Chattanooga Times Free Press* on Feb. 4, 2012. TVA power sales in the fourth quarter of 2011 were cut by \$260 million compared with the same quarter a year earlier. Electric demand in the residential sector is more sensitive to weather than in the industrial sector.

Recent Corporate Announcements

On Jan. 26, 2012, FirstEnergy Corp. announced plans to retire six older coal-fired power plants in Ohio, Pennsylvania, and Maryland, citing the EPA's mercury and air toxics standards as the cause. Other facts suggest that market conditions, combined with the remaining useful life of the plants, played a significant role in the company's decision. Most of the retiring units are between 50 and 60 years old. They are all "merchant" power plants, whose financial performance is shaped by competitive power markets. FirstEnergy had already idled most of these units beginning in 2010 because of reduced demand for electricity and the need to reduce operating costs.

FirstEnergy's prior decision to retire the units by Sept. 1, 2012, suggests that market fundamentals led the company to reach the conclusion now, rather than closer to the date on which the company would need to comply with the EPA's mercury and air toxics rule (which is March 2015, at the earliest).

FirstEnergy has made similar decisions to retire older units in the past:

- Rockaway (Ohio): demolished in 2008
- Mad River Plant (Ohio): closed in 1981
- Gorge Plant (Ohio): mothballed in 1991
- Toronto Plant (Ohio): closed in 1993

- Edgewater (Ohio): closed in 2002

A second example is American Electric Power's June 2011 announcements of coal plant retirements. Although the EPA regulations were cited in the press release announcing the retirement of nearly 6,000 MW of coal plants, market dynamics and practical business decisions played an important role. AEP's CEO had told financial analysts at an investor conference the prior week that those coal plants were "high cost plants" and "in fact, throughout I think almost all of 2009 those plants probably didn't run 5% of the time because natural gas prices were such that they simply weren't dispatching. When we shut those down there will be some cost savings as well." In 2007, AEP had signed a consent decree covering many power plants, including all but one of the units in the 2011 retirement announcement; in that consent decree, relating to prior environmental litigation surrounding the plants, the company had already agreed to retire, retrofit, or repower 4,500 MW of these plants.

Since the EPA issued the final Mercury and Air Toxics Standards (MATS) rule, AEP has reported to investors that it has reduced its projected environmental compliance costs because of flexibility that the EPA has provided in terms of the particulate matter standards. AEP has also reduced its planned coal unit retirements. According to AEP CEO Nicholas K. Akins:

[A]s we go through this process, we originally looked at 6,000 megawatts being retired. I think now it's 5,200, since Big Sandy will stay online. But we also projected that we would replace that with about 1,500 to 1,800 megawatts of natural gas-fired capacity, so if this fuel switching is going to continue to occur, we're going to retire units that are out of the market as quickly as we can. And then as far as replacement with natural gas facilities, that'll be primarily the fuel of choice for us, because in our eastern footprint, we never had that really before, but now we have substantial pipeline capability and the advent of the Utica and Marcellus shale has just dramatically changed the way we look at natural gas in the future.

AEP management also told investors that the economic outlook in the 11 states where the company operates remains modest, with slight growth year-over-year expected in industrial and commercial sectors and flat residential load.

Other Factors Affecting Coal Plant Economics

New environmental requirements can put financial pressures on coal plant operators, but power market fundamentals, and especially tightened gas-to-coal price differentials and lower electricity demand, have contributed significantly to the recent business decisions of some coal plant owners to retire some of their marginal plants. Many market observers report continued pressure on the coal fleet in the near term, at a minimum, due to these economic drivers.

The timing of particular power plant retirement decisions may be triggered by other factors that affect the circumstances of a particular plant or a particular company. For example, a plant with marginal economics due to fuel market pressures might be tipped into retirement at the point when the company faces a maintenance-cycle milestone that would require a large investment just to keep the plant open for business. Similarly, a company might be facing more generalized workforce consolidation or labor agreement issues that contribute to the timing of closures of marginal plants. Companies sometimes time the announcements of closures to take advantage of tax opportunities or other matters affecting earnings in a particular financial reporting period. These triggers may not be as transparent as more obvious factors such as lower output levels and lower revenues received by certain plants, but they may affect the timing of some plant retirement events or announcements.

—Susan F. Tierney, PhD is managing principal for the Analysis Group Inc. Dr. Tierney is an expert on energy policy and economics, specializing in the electric and gas industries. She is also a former assistant secretary for policy at the U.S. Department of Energy and state public utility commissioner.

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BY JIM FUQUAY

jfuquay@star-telegram.com

DALLAS — Natural gas will continue to displace coal for power generation, and that represents the best opportunity for the gas industry to boost domestic demand and reduce bloated supplies, Exxon Mobil CEO Rex Tillerson said Wednesday.

Speaking to reporters after the company's annual meeting in Dallas, Tillerson predicted that "as additional electricity capacity has to be built out, there's going to be a substantial increase in natural-gas-fired power generation," both as a replacement for older coal-fired power plants and as a complement to wind power's fluctuating output.

Tillerson addressed the demand issue in relation to the Irving-based company's \$41 billion acquisition of Fort Worth-based XTO Energy two years ago. While Exxon expected natural gas prices to weaken from their levels at the time of the purchase, prices tumbled when the weak economy reduced demand and strong production from shale formations boosted supplies, he said.

But "there's no regrets" about the deal, he said, because "it's really about a 20- to 30-year view" of the marketplace, not a short-term bet.

During the shareholders meeting, Tillerson also repeated Exxon's interest in exporting natural gas from North America, where a supply glut has produced the lowest prices in a decade. Gas prices closed at \$2.42 per million Btu on Wednesday after falling as low as \$1.90 in April.

In response to a question about Cheniere Energy obtaining federal approval last month to build an export plant for liquefied natural gas on the Louisiana coast, Tillerson said Exxon continues to study the prospects of LNG terminals on the Gulf Coast and in western Canada.

Those facilities, which typically entail billions of dollars in investment, would ship gas to overseas markets where the fuel draws a much higher price.

With its XTO purchase, Exxon became the largest U.S. natural gas producer.

In actions at the annual meeting, shareholders rejected two environmental proposals, one calling for further disclosure of risks involved with hydraulic fracturing and the other seeking to set goals for reducing greenhouse-gas emissions in its massive operations.

By a 78 percent vote, they approved the company's executive compensation package, which included \$34.9 million for Tillerson in 2011, and by a lesser margin declined to split the CEO and chairman roles, which are both held by Tillerson.

The Rev. Michael Crosby, a Franciscan friar from Milwaukee, presented the shareholder resolution on fracking, noting that the process for extracting oil and gas from shale formations and its surrounding production activities can produce "tremendous social conflict."

He urged shareholders to focus on the impact on communities, and he chided Tillerson for the absence of any mention of global warming or climate change in Exxon's presentations.

He was followed by Sister Patricia Daly, a regular at the company's meetings, who sought support for the greenhouse-gas measure.

She said Exxon is a well-run, "goal-oriented company, but it doesn't want to set goals in this area."

Keep up with developments in the Barnett Shale

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Both environmental measures drew just under 30 percent support from the 3.8 billion shares voted at the meeting.

Jim Fuquay, 817-390-7552

Twitter: @jimfuquay



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6

TRANSCRIPT

DUKE - Q4 2011

Duke Energy Corporation Earnings Conference Call

FEBRUARY 16, 2012

OVERVIEW:

Management discussed 4Q11 results, reporting adjusted diluted EPS of \$1.46. Guidance was for 2012 adjusted diluted EPS of \$1.40-1.45.

CORPORATE PARTICIPANTS

Bill Currens *Duke Energy Corporation - IR*

Jim Rogers *Duke Energy Corporation - Chairman, President and CEO*

Lynn Good *Duke Energy Corporation - Group Executive and CFO*

Dhiaa Jamil *Duke Energy Corporation - Group Executive, Chief Generation Officer and Chief Nuclear Officer*

CONFERENCE CALL PARTICIPANTS

Daniel Eggers *Credit Suisse - Analyst*

Greg Gordon *ISI Group - Analyst*

Steve Fleishman *Bank of America Merrill Lynch - Analyst*

Jonathan Arnold *Deutsche Bank - Analyst*

Michael Lapides *Goldman Sachs - Analyst*

Hugh Wynne *Sanford Bernstein - Analyst*

Ali Agha *SunTrust - Analyst*

Jim von Riesenmann *UBS - Analyst*

Travis Miller *MorningStar - Analyst*

PRESENTATION

Operator

Good day everyone and welcome to the Duke Energy fourth-quarter year-end earnings conference call. Today's call is being recorded. At this time for opening remarks I would like to turn the call over to Mr. Bill Currens. Please go ahead sir.

Bill Currens - Duke Energy Corporation - IR

Thank you, Lauren. Good morning everyone and welcome to Duke Energy's fourth-quarter and year-end 2011 earnings review. Leading our discussion today are Jim Rogers, Chairman, President and Chief Executive Officer, and Lynn Good, Group Executive and Chief Financial Officer.

Today's discussion will include forward-looking information and the use of non-GAAP financial measures. This forward-looking information is based on Duke Energy as a stand-alone Company, as regulatory approvals for our merger with Progress Energy are still pending. You should refer to the information and our 2010 10-K and other SEC filings concerning factors that could cause future results to differ from this forward-looking information.

A reconciliation of non-GAAP financial measures can be found on our website and in today's materials. Note that the appendix to today's presentation materials includes additional disclosures to help you analyze the Company's performance as well as our 2012 earnings guidance assumptions.

In today's call, Jim and Lynn will review our fourth-quarter and year-end earnings and provide you with our 2012 earnings guidance and related assumptions. We will also update you on our strategic initiatives, including

Operator

Hugh Wynne, Sanford Bernstein.

Hugh Wynne - Sanford Bernstein - Analyst

Hi, I just wanted to follow up on some of the questions regarding coal for gas switching. In particular, what are the biggest impediments for your commercial power fleet and your US fleet to capitalize on lower gas prices?

I wonder if you could maybe comment on the difficulties of handling your coal contractual commitments, your rail contractual commitments, and for that matter, the difficulty of serving load during peak demand months like the summer, when both the coal and the gas fleets may be called into service. Can you give us a little bit of color on what the operational challenges are to respond to these new relative prices of gas and coal?

Lynn Good - Duke Energy Corporation - Group Executive and CFO

I will comment on the commercial business and I'm sure Jim will have something to add.

I feel like our commercial business is very well-positioned to operate in a low gas price environment. As I mentioned a moment ago, their generation volumes have just continued to steadily increase in this market condition, and we see that continuing from 2012 to 2013. And those assets are run directly into the market based on price signals in the market. We're prepared to run any day and every day, and have had very consistent run times for those gas assets.

In the coal fleet, you know, now that we are completely situated in the wholesale market, the coal fleet - non-regulated - we run them in an economic manner. If the coal is in the money, we run them. If it's not in the money, we don't. And maintain flexibility in the way we contract for coal to make that operationally successful.

And on FE&G, I think we have got a nice portfolio mix. I think about the Carolinas; what dispatches first are the nuclear plants. We're now bringing Buck in behind the nuclear plants, but still get into the coal stack at various times of the year and continue to look at ways that we can introduce flexibility into coal contracts. And I think that's part of everyday business and will continue to be.

Jim Rogers - Duke Energy Corporation - Chairman, President and CEO

I don't see any threat to our ability to meet peak demand because of the low coal -- gas prices or the blend of our coal and gas assets in meeting demand. I think we're well-positioned to meet any peak demand that we may have in the coming summer or future summers.

Operator

Ali Agha, SunTrust.

Ali Agha - SunTrust - Analyst

Lynn or Jim, I wanted to come back to your comments. And again just looking at Duke stand-alone little bit, dive a little bit more into the growth rate. The 4% to 6% you talked about from the 2009 base, which implies just mathematically if we were to push it up to 2011, the number would be mathematically lower than that, just given the way the math has worked.

7

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Executives

Daniel S. Tucker - Vice President of Investor Relations and Financial Planning

Thomas A. Fanning - Chairman of the Board, Chief Executive Officer and President

Art P. Beattie - Chief Financial Officer and Executive Vice President

Analysts

Dan Eggers - Crédit Suisse AG, Research Division

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Paul T. Ridzon - KeyBanc Capital Markets Inc., Research Division

Angie Storozynski - Macquarie Research

Brian Chin - Citigroup Inc, Research Division

Mark Barnett - Morningstar Inc., Research Division

Ali Agha - SunTrust Robinson Humphrey, Inc., Research Division

Marc de Croisset - FBR Capital Markets & Co., Research Division

Michael J. Lapedes - Goldman Sachs Group Inc., Research Division

Greg Gordon - ISI Group Inc., Research Division

Steven I. Fleishman - BofA Merrill Lynch, Research Division

Kit Konolige - Konolige Research, LLC

James L. Dobson - Wunderlich Securities Inc., Research Division

Paul Patterson - Glenrock Associates LLC

Dan Jenkins

Anthony C. Crowdell - Jefferies & Company, Inc., Research Division

Southern (SO) Q1 2012 Earnings Call April 25, 2012 1:00 PM ET

Operator

Good afternoon. My name is Sarah, and I'll be your conference operator today. At this time, I would like to welcome everyone to be Southern Company First Quarter 2012 Earnings Call. [Operator Instructions] I would like to turn the call over to Mr. Dan Tucker, Vice President of Investor Relations and Financial Planning. Please go ahead, sir.

Daniel S. Tucker

Thank you, Sarah. Welcome, everyone, to Southern Company's First Quarter 2012 Earnings Call. Joining me this afternoon are Tom Fanning, Chairman, President and Chief Executive Officer of Southern Company; and Art Beattie, Chief Financial Officer.

Let me remind you that we will make forward-looking statements today in addition to providing historical information. There are various important factors that could cause actual results to differ materially from those indicated in the forward-looking statements, including those discussed in our Forms 10-K and subsequent filings.

We'll also be including slides as part of today's conference call. These slides provide details on the information that will be discussed on this call and you can access the slides on our Investor Relations website at www.southerncompany.com if you want to follow along during the presentation.

Now at this time, I'll turn the call over to Tom Fanning, Southern Company's Chairman, President and Chief Executive Officer.

Thomas A. Fanning

Thanks, Dan. Good afternoon, and thank you for joining us. Before we turn to Art for a review our first quarter performance, I'd like to take a few moments to update you on our recent progress on several important strategic fronts.

On February 10, we received the combined construction and operating licenses for Plant Vogtle Units 3 and 4, the first new nuclear units licensed in the United States in more than 30 years. Our nuclear development team has done an exemplary job in satisfying the requirements for these licenses, and I have every confidence that they will continue to provide strong leadership as the project moves forward.

We are making significant progress at Vogtle 3 and 4 as those of you following along on the slides can see. Work is already underway on the Nuclear Islands and cooling tower, and our heavy-lift derrick, one of the largest in the world, is being assembled. With the new licenses in hand, we have made a smooth transition into the next phase of the project and I look forward to sharing further updates with you in the future.

Meanwhile, the state regulatory process for Vogtle 3 and 4 continues to move forward in a constructive manner. The Georgia Public Service Commission has improved \$1.7 billion of project costs through June 30, 2011, and is currently reviewing the company's sixth semiannual construction monitoring report, which reflect an additional \$300 million of cost through December 2011. In testimonies filed with the commission, Georgia Power has outlined up to \$2 billion of potential additional benefits related to Vogtle 3 and 4 that we believe further enhance the value of this project for our customers. The commission's decision in this proceeding is expected in mid-August.

With any project of this magnitude and length, commercial disputes are to be expected. Discussions between the owners and the consortium are ongoing regarding a number of matters, including issues related to the timing of the receipt of the design control document, or DCD, and the combined operating licenses, or COLs. As you may be aware, the construction of Vogtle 3 and 4 will proceed under a new licensing framework that is significantly different from the one used previously.

In the past, nuclear plant operators designed and built their units first and then sought licensing approval for what they had already built. Under the new process, the nuclear units are constructed according to the COLs and the underlying DCD. There are processes in place to assure compliance with the design requirements specified in the DCD and the COLs. One process we have discussed with you before is ITAAC, which stands for inspections, tests, analyses and acceptance criteria. An additional oversight process is rigorous inspection by Southern Nuclear and the NRC that occurs throughout constructions.

As an example of this process, a recent routine NRC inspection revealed that limited details of the rebar construction in the Unit 3 Nuclear Island were not consistent with the DCD. We expect to receive official notice of this finding from the NRC. In the meantime, we are engaged in constructive discussions with the consortium to identify appropriate action. We can reasonably expect to encounter additional inspection issues between now and the time the new units are completed as they are a normal part of the nuclear construction process. Our goal is always the same: to build the safest, most reliable and most cost-effective nuclear generating units possible and to achieve our targets with regard to schedule and cost to customers.

Elsewhere, on April 24, the Mississippi Public Service Commission finalized a new certificate of public convenience and necessity for the Plant Ratcliffe in Kemper County, Mississippi. This became necessary after the Mississippi Supreme Court's recent reversal of the commission's previous order. In the interim, construction continued on the Kemper County site under a temporary authorization granted by the PSC on March 30 and will now proceed under the authority of the new permanent order. Initial startup and testing are now only 14 months away, and we remain confident that this project will provide the best value to customers over the long term. Targets remain achievable for both the Vogtle and Kemper County projects with regard to construction schedule and cost to customers.

As important as these projects are, they are only part of our all in "arrows in the quiver" strategy for building a 21st century energy portfolio. Georgia Power is making significant progress on 3 new combined-cycle natural gas units at Plant McDonough. The first of these units came online in December and with a nameplate capacity of 840 megawatts, and has actually been generating at significantly higher levels with an extremely efficient heat rate. The second unit is scheduled to begin operation later this month with the third unit expected to follow in November.

Southern Power is also nearing completion of the nation's largest biomass generation facility near Nacogdoches, Texas. This project, which is scheduled to begin commercial operation in June, will provide needed power for the city of Austin through a 20-year contract. These projects are consistent with our ongoing commitment to maintain a diverse and balanced generation portfolio, thereby enabling customers to benefit from the best available combination of low energy costs and system reliability.

During our last earnings call, we reported that our energy mix in the fourth quarter of 2011 was about 40% natural gas and 40% coal, with the rest coming from our lowest cost resources, nuclear and hydro. Compare that to 2007, where the mix was only 16% natural gas and 70% coal. As natural gas prices have remained low relative to other fossil sources, we have seen these fourth quarter trends continue. We now project that our mix for the full year of 2012 will be 47% natural gas and only 35% coal.

Given the high level of interest in this topic across our industry, here is a quick summary of what we're seeing here at Southern Company. During the first quarter of 2012, our natural gas combined cycle fleet achieved an average capacity factor of 70%. Based on today's forward curves, we estimate we could burn more than 600 Bcf for the full year 2012 or about 1.7 Bcf per day, almost 3x what we burned in 2007 when natural gas was only 16% of our generation mix.

Southern Company's gas purchases now account for more than 2% of all United States natural gas consumption, making us the third-largest user of natural gas among United States utilities. Even with natural gas prices below our forecast for 2012, we are well-positioned for managing coal inventories and passing lower energy costs on to customers.

To accomplish this, we've taken several proactive steps, which include increasing our ability to match coal purchases and burn through reduced volumes of contracted coal, maximizing and expanding on-site and off-site storage, working with our coal suppliers to defer, buy out or renegotiate existing contracts, and conducting managed burns when necessary. Our current expectation is that we will burn less than 45 million tons of coal in 2012 compared to the nearly 80 million tons we've burned at our peak in 2007. That said, we continue to maintain our operational flexibility to increase our use of coal in the event of a sharp reversal in the price of natural gas.

There remains excellent optionality in our generation fleet. As an illustration, by 2020, assuming a scenario of low natural gas prices and relatively high coal prices, our energy mix could be 57% gas and 22% coal. If fuel prices change to a high-gas, low-coal environment, the energy mix could be 34% gas and 45% coal. Under all scenarios, nuclear would remain in the 16% to 17% range. This level of flexibility will continue to be an important part of our operational planning philosophy going forward.

As always, our ultimate goal is to benefit customers, and here, we continue to succeed. As an example, earlier this year, Georgia Power filed a request to lower fuel rates. As proposed, this would reduce average fuel prices by 19% and average residential retail prices by 6%. We think achievements of this sort are the very best validation of our business model, that everything we do is based on providing the best value for customers served by our operating system.

I'd like to turn now to Art Beattie for a discussion of our financial highlights for this quarter, as well as an update on first quarter sales, the economic outlook for our region and our earnings estimates for the second quarter.

Art P. Beattie

Thanks, Tom. In the first quarter of 2012, we've reported earnings of \$0.42 per share compared with \$0.50 a share in the first quarter of 2011, a decrease of \$0.08 a share.

Let's turn now to the major factors that drove our numbers for the first quarter of 2012 compared to the first quarter of 2011. First, the negative factors. Weather effects reduced our earnings by \$0.08 a share during the first quarter of 2012 compared with the first quarter of 2011. Weather was actually \$0.06 a share below normal in the first quarter of 2012 compared with \$0.02 a share above normal in the first quarter of 2011. Increases in non-fuel O&M expense for our traditional operating companies decreased our earnings by \$0.01 a share in the first quarter

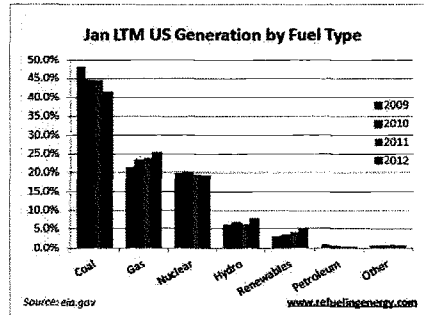
8

Refueling Energy

Discussing the transition from fossil fuels toward a sustainable energy economy

Tuesday, March 27, 2012

An Historic Day in United States Power Generation

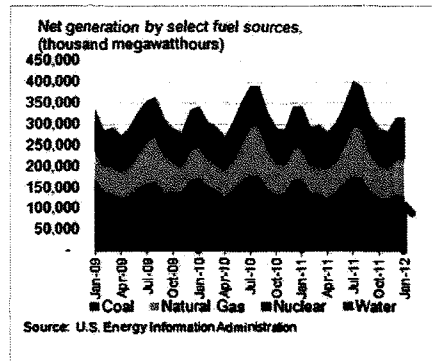


Last Twelve Month Electric Power Generation in the US

Today is an historic day in the history of American electric power generation. With the release of the January Electric Power Monthly Update, it has become clear that for the first time ever, total power generation from natural gas and renewable sources including hydroelectric exceeded generation fueled by coal. This is a seismic shift as coal has dominated the US power grid since the invention of the light bulb. As a source of power, coal is being rapidly displaced by natural gas and renewables at a rate that virtually no one had thought possible. As recently as January 2012, the EIA projected in its Annual Energy Outlook Early Release that coal would remain the dominant fuel for power generation over the next two decades:

"The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens coal use in the future. The AEO2012 Reference case includes the impacts of the CSAPR, which was finalized in July 2011 and was not represented in the AEO2011 Reference case. CSAPR requires reductions in SO₂ and NO_x emissions in roughly one-half of the States, with an initial target in 2012 and further reductions in 2014. Even so, coal remains the dominant energy source for electricity generation, but its share of total generation declines from 45 percent in 2010 to 39 percent in 2035."

The Facts

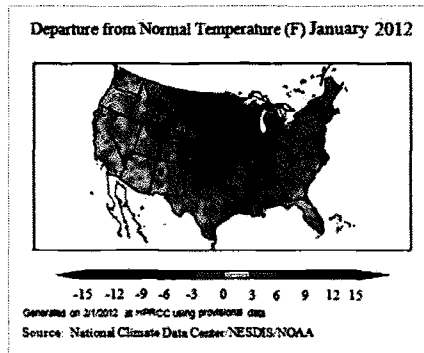


In 2011, coal represented 42% of total US electric power generation - but in January 2012 coal represented just 38%, compared to a 40% share for natural gas and renewables. In the first month of the year, coal generation has already declined to the level the EIA projects it will reach after 23 years of gradual displacement from increasing regulations, growth in renewables and natural gas-fired generation. It should be noted that January is traditionally a strong month for coal power generation, as shown by the blue lines in the chart at left. Instead, power generation from coal plummeted 25% in January 2012 as compared to January 2011, or 41,919,000 MWh, to 129,064,000 MWh. A megawatt-hour, or MWh, is enough energy to power the average US household for a month. In the same month, natural gas-fired generation increased 23% to 91,213,000 MWh and generation from non-hydro renewables increased a remarkable 36% over January 2011 to 20,245,000 MWh. This seismic shift occurred within days of the EIA issuing its projections through 2035, highlighting how many seasoned market observers are fundamentally underestimating the impact of declines in the cost of natural gas and renewable power - and likely overestimating the impact of environmental regulations.

Opponents of new EPA regulations, including the highly controversial CSAPR rule which will substantially lower air pollution along the Eastern Seaboard, should take note that the impact of all new EPA regulations over 23 years as projected by the EIA is less than the impact of low natural gas prices in one month - despite the fact that CSAPR was stayed just two days before it was scheduled to go into

noted that, as of January 2012, virtually none of the EPA's other recent major rules had gone into effect, and yet we are still seeing a fundamental shift in the landscape of power generation without any impact on grid reliability.

Causes of the Decline of Coal



Low natural gas prices driven by hydraulic fracturing are causing record coal to gas switching just as massive amounts of new renewable power generation capacity come online and record winter warmth across the United States and continuing energy efficiency efforts reduce total electric energy consumption. Hydro generation also continues to remain strong, continuing a trend that began about one year ago. For the past few months, coal consumption for power generation has been declining at a rate of approximately 20% year-over-year while natural gas consumption has surged. Opponents of hydraulic fracturing should note the significant environmental benefits of the coal to gas switching, including up to a 70% reduction in carbon emissions, 90% reduction in carbon monoxide and nitrogen oxides, and a nearly 100% elimination of sulfur dioxide (SO₂), particulate matter and mercury emissions.

Policy Implications

The last time the US consumed more energy from renewable sources than from coal was in the mid-1880s, when wood was the primary fuel used and coal production was only beginning. Heavy subsidization of the coal, oil and gas industries in the late 19th and early 20th century quickly resulted in a fossil fuel dependency. As a result, the only way to level the playing field is actually to heavily subsidize renewable energy research and deployment for decades to develop the scale and infrastructure required to challenge incumbents, just as coal eventually displaced wood after decades of subsidies. While there is certainly a long way to go toward a renewable energy economy, relatively clean natural gas combined with renewable power generation have resulted in a rapid market shift away from dirtier legacy fossil fuels such as coal even as support for renewables fades. The rapid decline of coal is a strong market signal that it is no longer an economic source of power generation.

The current federal policy environment continues to resist the clear market trend emerging as most major renewable energy subsidies have already expired or will expire at the end of 2012. Meanwhile, three out of the four permanent tax breaks continue government support for fossil fuels, while the fourth supports nuclear power. The permanent tax breaks were valued at \$3.6 billion annually in 2011, illustrating a continuing dependency of fossil fuels on government support even as fossil fuel supporters inaccurately criticize renewable technologies for being uneconomic. It is time to embrace the future and end subsidies for fossil fuels that the market is clearly telling us are not economic in order to fully enjoy the benefits of clean, cheap and sustainable energy sources.

Update 3/28/2012:

The EPA's "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3," released late yesterday, is certainly a bold step in the right direction. This mechanism fairly helps to internalize external costs not previously recognized by the market. However, critics' cries that the rule will be the death of new coal are misleading and concealing the fact that coal is declining just fine on its own as its economics, even ignoring externalities, just don't make sense.

Charts courtesy of the EIA

Posted by Rhys M. at 7:19 PM

Labels: carbon, coal, economics, electric power, fuel, natural gas, policy, projections, regulation, renewable power, renewables

No comments:

9

The Washington Post

[Back to previous page](#)



The demise of coal-fired power plants

By **Steven Mufson**, Published: November 23

In SALEM, Mass. — Peter Furniss, the fair-haired chief executive of Footprint Power, gives a tour of the aging coal and oil plant that towers over sailboats in this historic harbor.

The Ivy League-educated lawyer, clad in unsoiled work boots and a pinstripe jacket, circles a mound of coal and walks inside a rusting oil storage tank. He gingerly steps into a tunnel where a conveyor belt carries coal into the plant's furnaces.

Inside the plant, Furniss points out the Roman arches and graceful columns in the turbine room and the half-century-old control panel, an antique compared with the computers that run equipment now. He shows off the boilers and pulverizers. Finally, from the roof, he surveys the scenic coastline, which fades into the autumn fog.

For years, this coal plant — known as one of the state's "filthy five" — has flirted with closure and avoided a costly overhaul that would bring its toxic emissions in line with modern pollution standards. In 2003, Gov. Mitt Romney (R) stood in front of the plant and declared: "I will not create jobs that kill people. That plant kills people."

Nine years later, two of Salem Harbor power plant's generating units are still operating and the other two, including an oil-fired unit, closed last December.

Now, however, the prospect of long-lasting cheap natural gas supplies has sealed the fate of the plant. In

August, Footprint Power, run by a group of former utility executives, bought the 60-year-old plant from Dominion Resources and announced they would tear it down in 2014 and replace it with a cleaner, more economical natural-gas-fired unit.

“When we were first looking at the overall project, it really was a toss-up as to whether it would be more the environmental rules or the gas price that was going to drive coal plants to shut down,” said Furniss, 45. “It now is very clearly the gas price.”

Salem Harbor is a case study of how the shale gas revolution is overthrowing assumptions about energy by undercutting coal prices and usurping it as the nation’s fuel of choice for electric power generation.

Across the country, utilities are switching from coal to cheap natural gas. In April, for the first time, natural gas pulled even with coal as a fuel source for power plants. Through August, the use of coal to generate electric power had tumbled 17 percent while the use of natural gas jumped 27 percent, according to the Energy Information Administration.

As of July, companies had announced plans to close down 30 gigawatts of coal-fired plants, or about 10 percent of the nation’s total coal plant capacity, by 2016, according to a study by the Brattle Group, a consulting firm. These aren’t models of efficiency; the EIA says that the average coal-fired generator to be retired this year is 56 years old.

Overall, this transition might cause the loss of jobs in some coal mines, but it is also creating jobs in areas rich in shale gas. Moreover, the gas glut is cutting utility bills for households and businesses, giving a much-needed boost to the lackluster economy.

In Ohio, for example, households and businesses in 2011 saved about \$1.85 billion, or about 20 percent of gas and electricity fuel costs compared with the average from 2007 through 2009, according to Richard Smead, a director of the economic advisory firm Navigant Consulting. The average household saved \$232.

Natural gas emits about half as much carbon dioxide as coal does in a power plant. In the first quarter of 2012, carbon dioxide emissions from coal burning fell to the lowest level for any quarter since 1986, according to the EIA.

Overall, U.S. greenhouse emissions fell to their lowest level in 20 years, though warm weather last winter and lower gasoline consumption also played roles. Still, the United States is roughly on track to meet the reduction in greenhouse gases that President Obama has pledged to hit by 2020.

The old and the new

As Salem Harbor shows, the coal industry is primed for upheaval.

The plant opened in 1951. The original GE turbine still anchors the operation. Outside, emission stacks soar as high as 491 feet. Mounds of coal, delivered by barges, sit beside the wooden dock. Automated sprinklers dampen the piles so they don’t blow away.

Another throwback: The plant was grandfathered under EPA regulations so that it never had to meet the same environmental standards as new plants. And a 2000 Harvard School of Public Health study estimated that the power plant’s emissions could be linked to 53 premature deaths, 16 heart attacks, 14,400 asthma attacks and 570 emergency room visits.

The new owners, Footprint Power, know full well the plant's limitations. To meet environmental standards now, Furniss said, the plant imports low-sulfur coal from Colombia.

The plant runs only when the regional grid managers call on it — which they do based on the weather and the prices at which competing power plants are offering electric power.

Firing up the plant is time-consuming. It takes 10 or 12 hours to get the pulverizers going and the boiler temperatures up. On Oct. 4, the plant was fired up for just the second time since August. It has run 15 more times since then, mostly to provide reliability for the regional grid system.

Compare that with the \$800 million natural gas plant Footprint Power hopes to build along with its partner, Toyota Tsusho, part of the Toyota group.

The highest exhaust stack on the natural gas plant will be 230 feet, less than half the tallest of the coal plant stacks. The new plant would be cooled primarily by air and would use 100,000 gallons of water a day; the coal plant cools itself with 100 million gallons of water a day from the harbor, Furniss said. And, with a new generation of gas turbines GE unveiled in September, the plant could ramp up in as little as 15 minutes, not 10 hours. (In Colorado, utility Xcel has already bought GE's turbines for a new natural gas plant that will replace a handful of closed coal plants.)

The Salem natural gas would probably be drawn from Spectra Energy's Algonquin pipeline, which passes just a couple of miles away. The volume of gas flowing through the Algonquin has surged thanks to supplies from the vast Marcellus shale gas play that stretches across Pennsylvania into adjacent states. The coal mounds would disappear.

"Obviously gas is pretty cheap, and one of the things keeping it pretty cheap is the Marcellus," Furniss said. "We assume that prices will rise as the market becomes more mature." While prices today are about \$3.80 per thousand cubic feet, Furniss said that Footprint Power assumes prices will not exceed \$6 "at the upper end ... in the foreseeable future."

Furniss said Footprint hopes to get permits by the third quarter of 2013. If the Massachusetts Department of Public Utilities decides the new plant is needed for the reliability of the regional grid, Footprint Power will find it easier to line up contracts and financing.

The effects of cheap gas

About a decade ago, the big talk in the utility business was about tossing off the yoke of public service commissions, getting away from steady but modest regulated returns and becoming independent or "merchant" power companies selling electricity to hungry grids that would pay steep prices. The restructuring left many local utility companies, such as Pepco and Baltimore Gas & Electric, without their own power plants and many power plant owners without their own local distribution companies.

Cheap natural gas has decimated those strategies. Its price has dropped so low that merchant power plants using other fuels have been forced to shut down or sell electricity at bargain basement rates.

PPL is a major utility that had re-created itself back when gas was expensive and merchant power was in vogue. The company had positioned itself so that 70 percent of the electric power it generated was sold like a commodity by its "merchant" plants while 30 percent was sold by regulated plants assured of modest rates of return.

Then at a board meeting in Allentown, Pa., in July 2008, the directors realized that cheap natural gas was about to destroy their new business model. Someone charted the PPL stock price, which was closely correlated to natural gas prices, which were starting to plunge. One scenario written up for the board forecast a growing gas glut.

“As we sat around that table, the ‘a-ha moment’ was when we realized we were making a bet on a business we could not control,” PPL chief executive Bill Spence said. “We realized that those reductions in natural gas prices could have devastating effects on our earnings.”

So, he said, “we did a complete 180.” Goodbye, competitive markets; hello, regulation.

To rebalance itself, the company rushed out and spent about \$13 billion buying two regulated utilities, one in Britain and one in Kentucky. Today its position is reversed so that 75 percent of its operations are regulated and 20 to 25 percent are selling power into competitive markets. Now PPL plans to spend \$18 billion over the next five years, and it expects to get a safe regulated return on that investment.

One of those projects: A new natural-gas-fired plant in Kentucky that will replace three half-century-old coal plants with a total of 800 megawatts of capacity.

If PPL hadn’t changed direction, Spence said, “we would potentially have been in junk bond status and our ability to pay dividends might have been called into question.”

A repeat of history?

The last time the United States made a dash to gas, it ended badly. From 1998 to 2001 utilities quickly built 70 gigawatts of natural-gas-fired plants; from 2001 to 2003, they added another 105 gigawatts. Most of those plants — with more than enough capacity to replace the nation’s entire nuclear power fleet — went idle as gas prices soared, hitting \$15 per thousand cubic feet after Hurricane Katrina.

Will this time be different?

Gas-producing companies say that supplies are plentiful enough for decades to come. Indeed, they’re plentiful enough to hurt the prospects for renewable energy, too, said Bob Shapard, chief executive of Texas utility Oncor. “When you have power this cheap, and the idea that gas is there and plentiful and will last forever, you lose the focus,” Shapard said.

“Natural gas is being talked about as serving as ‘a bridge fuel’ but could very well wind up being locked in as the next-generation fuel, which would not be good at all,” Lisa Nurnberger, then-spokesman for the Natural Resources Defense Council, said earlier this year. “Natural gas could wind up crowding [out] renewables.” (Nurnberger is now a spokesman for the Union of Concerned Scientists.)

But prices could rebound somewhat with an improved economy and a cold winter, and some experts caution that the switch to gas might slow down, even if it doesn’t reverse. The newest and most efficient coal plants, relatively few in number, might be able to compete. Furniss said that even Salem Harbor expects to run more often during the winter thanks in part to the recent uptick in gas prices.

The giant utility AEP stands in the vortex of the price and planning maelstrom. One of the two biggest consumers of coal in the United States, AEP over the past decade bought idle natural gas plants at pennies on the dollar when gas prices were high. AEP used them only occasionally during peak times, such as hot summer days. But this year, AEP has been running the gas plants at around 70 percent of

their capacity, much higher than expected. Meanwhile, its coal plants have been running a little less than half the time, the company said.

“In years past, we used as much coal as we could,” AEP chief executive Nicholas K. Akins said. “In our system, we used to use 80 million tons a year. This year, we only expect to burn about 55 million tons.”

AEP is completing work on a highly efficient “ultra-supercritical” coal plant, but Akins said that “for the next decade if not longer we are not building any new coal units.” He said future plants would tap gas flowing from the nearby Marcellus and Utica shale reserves that Akins calls a “tremendous benefit and tremendous game changer.”

Recently, however, as natural gas prices have edged up, AEP is starting to see its coal plants picking up.

“For us, you get in that gas price of \$3 to \$3.25 per [thousand cubic feet], you’re going to start that switch to — back to — coal,” Akins said on an earnings conference call Oct. 24. “I think for other utilities, it’s higher.” He noted that “our mines were located close to the plants and ... coal comes in by the river and we have pretty advantageous contracts.”

In Kentucky, officials face a dilemma. AEP has a coal plant there that needs \$1 billion of scrubbers and other environmental controls to stay open past 2015. State officials would like to keep it open because Kentucky coal mines supply the plant. But the state doesn’t want to approve the \$1 billion in retrofits, which Akins says would increase electricity rates by 30 percent, hurting consumers and businesses. On the other hand, the state needs the generating capacity and building a new natural gas plant will also cost nearly \$1 billion.

So will gas stay cheaper than coal?

“The issue becomes where do you think gas prices are going to go versus where you think coal prices are going to go,” Akins said in the interview. “It’s a difficult proposition.”

‘A bridge to the future’

Meanwhile, at the Salem Harbor docks, Footprint Power has paid a consulting firm to collect bore samples 100 feet deep to figure out how to clean up once the coal is gone.

The new natural gas plant would take up only a third as much space as the coal plant, so the town of Salem could expand its dock for bigger ferry boats or even cruise ships. The town has built a tourist industry around the history of the witch trials of 1692 and 1693. Just outside the plant stands another attraction, the “House of Seven Gables” that Nathaniel Hawthorne used as the model for his novel about a home cursed by a man wrongfully hanged for witchcraft.

All things being relative, the community is pleased. “I was quite publicly opposed to the idea of another fossil-fuel-burning power plant replacing the existing fossil-fuel-burning plant,” said Lori A. Ehrlich, a state representative who stood near Romney the day he criticized the plant in 2003. “I saw it as an opportunity for a bit more imagination.” She would have preferred a marine biotechnology development now underway at a different old coal plant site down the coast.

“That said,” she added, “I would choose a brand new, cleaner-burning natural gas plant over a 1950s-vintage, unscrubbed, coal-burning power plant any day. So it’s a vast improvement.”

“This plant is not the future, but it is a bridge to the future,” Furniss said. “This project is screaming to be done.”

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10

"beyond detectable limits" because "many coal-fired plants are already achieving the mercury standards in the proposed rule and are in fact exceeding the standards by a significant margin."

Bracewell & Giuliani partner Jeffrey Holmstead, the counsel for Tri-State in this case, fired back that while some plants have met one of the three areas of standards for MATS, no plant has shown that it can meet the agency's limits for mercury, acid gases and non-mercury metals simultaneously. "I'm quite confident that there is not a single source that meets all of them," he said in an interview.

The developers' motion focuses on standards specifically for new sources, which Holmstead said are more stringent than the rules for existing plants. While the EPA cites data from the emissions of a specific plant to set the model for the mercury and acid gas limits, the developers, in their motion, disputed the agency's analysis. "The data in the record shows that even that source has emissions much higher than the standard," Holmstead said.

In addition, the developers asked the court to expedite their complaints against the EPA by agreeing to a proposed schedule for review of the lawsuit. "[T]he Holcomb 2 project faces time pressure to begin construction because of a time-limited air quality permit and because customers for the project's output will soon face the need to make alternative supply arrangements," the developers said.

Stage set for significant coal-to-gas switching in remainder of 2012

By Jesse Gilbert and Steve Piper

Dispatch competition between U.S. coal and natural gas fleets represents one of the key factors dramatically reshaping energy markets. Fuel switching, which was squarely in play in 2009, abated in 2010 before rising again late in 2011 as natural gas prices fell sharply. The recent drop in natural gas prices to better-than-10-year lows has once again set the stage for significant coal-to-gas switching in 2012.

A new white paper from SNL Energy examines the potential for coal-to-gas switching in 2012. Results from the analysis show a maximum potential of up to 3.8 Bcf/d of incremental gas demand for April through December over 2011 levels.

Coal-to-gas switching over the past several years has largely been limited to the eastern U.S., but as natural gas prices have fallen, some observers have said, the door might be open for more switching in other regions such as Electric Reliability Council of Texas Inc. and the Midwest ISO. SNL Energy found that the greatest switching potential remains concentrated in the East, though some moderate expansion looks possible in the Midwest and to a lesser degree in ERCOT. The CENTRL subregion, home to the Tennessee Valley Authority, may also see an increase in coal displacement by natural gas.

Developments in commodities markets and coal to gas parity

After the record heat in July 2011 subsided, natural gas prices began to fall as shale-driven production far outstripped demand. Mild weather in the winter and early spring has offered little support, driving gas prices down further through April. The Henry Hub spot price as of April 23 was \$1.86/MMBtu after having broken the key \$2.00 barrier in the first trading days of April. The current NYMEX Henry Hub forward curve for 2012 shows prices at around \$2.00/MMBtu for the May contract, rising to just under \$3.00/MMBtu by the closing December contract.

The U.S. Energy Information Administration storage report for the week ended April 13 showed total working gas in storage standing at 2,512 Bcf, with working inventories 871 Bcf higher than the year-ago volume and 919 Bcf above the five-year average. At the current rate of building, many expect natural gas inventories to reach levels that will exceed available storage capacity. This has led to fears among some analysts of a further collapse in natural gas prices unless there are significant cuts in production.

Rig counts have fallen in 2012 as a number of companies have announced production cuts in dry-gas plays. High oil and liquids prices, however, continue to drive incidental natural gas production in wet plays, which has more than offset dry-gas losses.

The aforementioned mild winter coupled with lower coal generation resulting from competing gas generation has pushed up coal inventories and driven down prices across the country. Physical market prompt-quarter prices for Central Appalachia 12,500-Btu/lb coal have fallen nearly 20% from 2011 levels, to \$2.52/MMBtu as of April 13. Northern Appalachia 13,000-Btu/lb-coal prices have fallen 13% over the same time period, reaching \$2.55/MMBtu as of April 13. Powder River Basin 8,800-Btu/lb coal has seen the sharpest drop-off from 2011 levels, at 35%, sitting at just 51 cents per MMBtu in the middle of April. Prices for Illinois Basin rail 11,800-Btu/lb coal are nearly flat compared to 2011 levels, dropping just 1%. By comparison, Henry Hub spot prices fell more than 50% over the same time period.

Looking toward the second half of the year, the drop in coal prices may be tempered as recently announced production cuts could help bring the oversupplied market back into balance. Analysts point to 35 million tons of production cuts formally announced by major coal producers through the middle of April. Early EIA coal production numbers for the first quarter of 2012 support this, with coal production numbers falling noticeably. The EIA estimates that through April 7, U.S. coal production is down 6.6% compared to the same period of 2011.

High coal inventories may serve as a headwind for coal-to-gas switching in 2012 as operators may be forced to burn coal to make room for minimum tonnage requirements from existing contracts. Data from the EIA shows U.S. coal stocks at nearly 200 million tons in March, testing the high of nearly 204 million tons, seen in November 2009.

The chart below shows regional gas floors at which a typical coal plant might be displaceable based on current market economics. A [previous analysis](#) by SNL Energy in August 2011 found that switching potential was largely isolated to Central and Northern Appalachia coals. Current data, however, shows that economics may be in place for some displacement of Illinois Basin and PRB coals.

To see a refreshable template that calculates regional gas floor prices for potential coal displacement based on default or user-selected parameters, click [here](#).

Natural gas floor prices for regional coal displacement					
	NAPP	CAPP	Ill. Basin	Rockies	PRB
Avg. Btu/lb	13,000	12,500	11,800	11,500	8,800
SO ₂ (lb/MMBtu)	3.1	1.6	5.1	1.0	0.8
Coal Market Price*	66.4	63.1	51.5	35.2	8.95
Estimated shipping costs (\$/Ton)**	18.00	25.00	10.00	22.50	22.50
Cost of coal delivered	84.40	88.10	61.50	57.70	31.45
Sulfur Dioxide (SO₂)					
Allowance price of SO ₂ (\$/ton)	0.82	0.82	0.82	0.82	0.82
Cost of SO ₂ per ton of coal (\$/ton)	0.03	0.02	0.05	0.01	0.01
Cost of SO ₂ per MMBtu (\$/MMBtu)	0.0013	0.0007	0.0021	0.0004	0.0003
Total coal cost per MMBtu before NO _x (\$/MMBtu)	3.25	3.52	2.61	2.51	1.79
Nitrogen Oxide (NO_x)					
NO _x Rate of marginal coal generation (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15
Allowance price of NO _x (\$/ton)	16.67	16.67	16.67	16.67	16.67
Cost of NO _x per ton of Coal (\$/ton)	0.02	0.02	0.01	0.01	0.01
Cost of NO _x per MMBtu (\$/MMBtu)	0.0013	0.0013	0.0013	0.0013	0.0013
Total/all-in cost of coal (\$/ton)	84.45	88.13	61.56	57.72	31.47
Estimated additional plant O&M (\$/MWh)	1.50	1.50	1.50	1.50	1.50
Total cost per MWh from coal (\$/MWh)	35.60	38.52	28.89	27.85	20.27
Total coal cost (\$/MMBtu)	3.25	3.53	2.61	2.51	1.79
Efficiency adjustment vs. CCGT power plant (%)^	40	40	40	40	40
Floor on natural gas (\$/MMBtu) - efficiency adjusted	4.69	5.08	3.80	3.66	2.65
* Per SNL Energy physical market prices for the third quarter of 2012 (04/13/2012)					
** Estimated using barge and railroad data from EIA and the Surface Transportation Board.					
^ Adjusted for the more efficient alternative (lower heat rate) CCGT power plant at 7,500 Btu/kWh average versus a 10,500 Btu/kWh average heat rate for coal plants.					
As of April 23, 2012.					
Source: SNL Energy					



The calculated floor on natural gas for Central Appalachian coal was found to be \$5.08/MMBtu, assuming average heat rates of 10,500 Btu/kWh and 7,500 Btu/kWh for coal and gas combined-cycle units, respectively. The calculated floor for Northern Appalachian coal using the same heat-rate assumptions was found to be \$4.69/MMBtu, while the floor for Illinois Basin coal was \$3.80/MMBtu and the floor for PRB coal was \$2.65/MMBtu.

It is important to point out that these calculated gas floors should not be compared to the spot price of natural gas, but rather to the variable cost of operating a CCGT plant, which includes a portion of non-fuel O&M, as well as the price of natural gas as delivered to the plant. Still, the data points toward continued significant potential for switching for Eastern U.S. coal, with expansion possible for PRB and Illinois Basin coal. The full SNL analysis found that PRB and Illinois Basin coal burned in Midwestern markets would see limited switching, while long-haul volumes into PJM Interconnection LLC and the Southeast were most susceptible to displacement.

Summary of key model results

SNL Energy used plant operational and fuel delivery data to identify a list of economically displaceable coal plants, along with maximum potential displacement from these plants in April through December 2012. Two scenarios were created to calculate costs, a maximum scenario using each plant's maximum heat rate from 2007 to 2011 and a minimum scenario using the minimum heat rate over this time. For each of these plants, a \$/MMBtu gas floor was calculated using the plant's heat rate, variable nonfuel O&M, delivered coal costs, and average costs for SO₂ and NO_x allowances. These plant gas floor calculations were compared to estimated marginal costs for combined-cycle plants in each plant's ISO/North American Electric Reliability Corp. subregion and for each remaining month of 2012.

Once displaceable plants for each forward month were identified, SNL Energy used continuous emissions monitoring system, or CEMS, hourly generation data to identify hourly displaceable coal generation in each region versus excess CCGT generation available in that hour.

Hourly displacement figures were aggregated for each region and shown by month. Under the maximum scenario, model results show a maximum call on natural gas of 3.8 Bcf/d for the rest of 2012. This is heavily skewed toward the earlier months, with average maximum displacement of 6.2 Bcf/d, 5.7 Bcf/d and 4.3 Bcf/d in April, May, and June respectively. This falls off as the year progresses, with a maximum potential call of 2.3 Bcf/d in December.

Natural gas displacement under max scenario (Bcf/d)										
Region	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Apr-Dec Average
NERC sub region										
AZNMSN	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.1
CENTRL	0.5	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.1	0.2
DELTA	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1
FL	0.3	0.3	0.2	0.2	0.0	0.2	0.3	0.3	0.1	0.2
RMP	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.1
SOU	0.9	1.0	0.4	0.3	0.2	0.4	0.5	0.4	0.6	0.5
VACAR	0.4	0.4	0.2	0.1	0.1	0.2	0.2	0.3	0.2	0.2
Within ISO										
CAISO	0.2	0.2	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.2
ERCOT	0.3	0.5	0.2	0.1	0.0	0.0	0.1	0.0	0.0	0.1
ISO-NE	0.2	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.1
MISO	0.2	0.4	0.7	0.4	0.5	0.2	0.2	0.1	0.1	0.3
NYISO	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.0	0.0	0.1
PJM	2.1	1.8	1.3	0.7	0.9	1.2	1.4	1.6	0.8	1.3
SPP	0.7	0.5	0.4	0.2	0.2	0.4	0.4	0.3	0.3	0.4
Total all regions	6.2	5.7	4.3	2.8	2.6	3.3	3.6	3.5	2.3	3.8
As of April 23, 2012. Source: SNL Energy										



PJM was found to have the most switching potential, with an average call on natural gas of 1.3 Bcf/d. The SOU NERC sub region followed, with a 0.5-Bcf/d potential. Switching outside of Eastern markets was found, but it is somewhat limited. Maximum potential in MISO was found to be roughly 0.3 Bcf/d, with ERCOT at 0.13 Bcf/d.

Generation displacement derived from the model was used to estimate the implied total drop in coal tonnage. Under the maximum heat rate analysis, this resulted in a total displacement of about 140,000,000 MWh of coal generation for the year. Using the average monthly heat rate of displaceable plants, this was converted

to total MMBtus displaced. Figures were calculated for the estimated fraction of displaceable MMBtus coming specifically from major coal regions, which was then used to derive individual tonnage amounts.

2012 displacement summary under maximum scenario										
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Displaceable capacity (MW)	144,915	149,093	149,550	139,594	124,596	118,519	107,364	97,416	85,453	124,056
Number of displaceable plants	189	192	196	186	171	169	161	151	137	201
Average heat rate of displaceable plants (Btu/kWh)	10,599	10,613	10,616	10,617	10,648	10,630	10,689	10,709	10,719	10,649
Generation displaced (MWh)	24,620,725	23,496,956	17,358,929	11,429,858	10,750,588	13,003,871	15,001,481	13,946,358	9,564,422	139,173,188
MMBTUs displaced	260,961,645	249,365,323	184,286,810	121,348,170	114,474,274	138,235,210	160,349,687	149,354,455	102,518,285	1,480,893,858
PRB (tons) displaced	2,487,210	2,411,937	1,819,482	881,558	795,855	661,648	879,752	702,652	417,689	11,057,783
CAPP (tons) displaced	3,147,236	2,939,769	2,285,835	1,633,487	1,688,193	2,111,839	2,800,563	2,988,040	2,233,013	21,827,974
NAPP (tons) displaced	2,569,857	2,408,944	1,674,559	1,179,876	957,576	1,339,962	1,205,486	837,928	599,819	12,774,007
Illinois Basin (tons) displaced	1,521,400	1,408,700	1,089,843	666,485	616,346	628,264	658,032	618,888	266,370	7,474,328
Other (tons) displaced	1,491,023	1,564,298	1,077,467	774,573	784,152	1,005,341	1,165,825	1,078,954	727,501	9,669,134
Total (tons) displaced	11,216,725	10,733,648	7,947,187	5,135,979	4,842,122	5,747,054	6,709,657	6,226,462	4,244,391	62,803,225
Total figure for average heat rate represents the weighted average heat rate of displaceable plants from Apr-Dec. Totals for displaceable capacity and number of plants represent the amount of capacity and plants found to be displaceable over any month from April to December. As of April 23, 2012 Source: SNL Energy										



Under the maximum scenario studied, this would result in a total displacement of nearly 63 million tons. Roughly one-third of this would come from Central Appalachia coal, with Northern Appalachia coal making up nearly 13 million tons, PRB coal accounting for 11 million tons and Illinois Basin coal accounting for nearly 7.5 million tons. Coal from other regions makes up nearly 10 million tons of displacement.

SNL Energy's estimates represent a maximum level of displacement based on plant economics and may overstate potential due to locational differences between competing natural gas capacity and transmission bottlenecks. The model also does not incorporate costs related to increased coal plant cycling resulting from switching, as well as operational constraints that may prevent instantaneous switching.

Overall expansion of switching into the Southwest and the Midwest looks possible but appears limited, though this could be expanded with further drops in natural gas prices. Additional switching in the CENTRL subregion looks likely, while the mid-Atlantic and Southeast remain largely out of the money. Coal stocks may serve as a headwind for switching in some regions, though strong economic incentives may result in some creative solutions for inventory control.

BPA Cuts Wind Generation

For the first time this spring, the Bonneville Power Administration invoked its controversial "Oversupply Protocol" and cut a total of 11,477 MWh of wind generation within its balancing authority over a two-day period at the end of April.

The curtailments were done in four episodes, primarily in the early morning hours of April 29 and April 30. A total of 5,118 MWh of wind production was stopped on April 29, between midnight and 6 a.m. and again from 11 p.m. to 12 p.m. On April 30, a total of 6,359 MWh was displaced, starting at midnight and lasting until 5 a.m., and then again for one hour, starting at 11 p.m. on April 30.

11

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THE WALL STREET JOURNAL

WSJ.com

BUSINESS | JANUARY 12, 2012

Glut Hits Natural-Gas Prices

By RUSSELL GOLD, DANIEL GILBERT and RYAN DEZEMBER



Benjamin Sklar for The Wall Street Journal

A worker checks water levels for a Goodrich Petroleum Corp. oil-fracking operation near Dilley, Texas.

U.S. energy companies are pumping so much natural gas out of the ground that prices are plummeting, and the cheap gas isn't likely to evaporate anytime soon.

Natural-gas prices fell 5.7% Wednesday to their lowest level in over two years—good news for people who use gas to heat homes and for companies that use it to power factories.

For U.S. energy companies, however, the domestic natural-gas market is looking increasingly out of whack. Despite a 32% drop in prices last year, onshore production rose 10%, and it is expected

to rise another 4% this year, according to Barclays Capital. As a result, prices are expected to remain low for at least the next couple years.

More

Natural-Gas Futures Slide

Many energy companies have shifted their focus away from natural gas to more profitable oil. Still, natural gas is often a byproduct of oil drilling, and some companies are opting to burn off the gas they find because they don't have a way to transport it.

For example, Goodrich Petroleum Corp.—reluctantly, it says—is flaring gas from an oil well on a ranch in South Texas because a nearby pipeline is already full.

Oil production isn't the only factor boosting natural-gas supplies. Some gas fields produce so much ethane, a valuable liquid used to make plastics, that companies will drill regardless of gas prices. In addition, some companies need to continue drilling so they don't violate terms of leases on millions of acres of land—deals struck when gas prices were high.

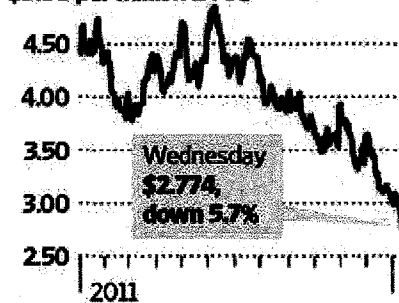
Wednesday's price drop on the New York Mercantile Exchange, to \$2.77 per million British thermal units for gas delivered next month, stemmed in part from new forecasts for warmer weather in several large heating markets, including New York and Chicago.

Cheaper Heat

Natural-gas futures fell for the third straight day Wednesday

Daily settlement price on the continuous front-month contract

\$5.00 per million BTUs



Source: SIX Telekurs

Earlier this week, Bank of America Merrill Lynch said gas prices could drop below \$2 in the fall, a level unseen since 2002. Four years ago, it sold for around \$9.

Eventually, the natural-gas market is expected to correct itself, either by forcing companies to further slash gas-development budgets or by luring in new gas customers. But industry observers say that could take many months, or even years.

The current glut partly stems from the U.S. energy industry's success with new exploration techniques—notably hydraulic fracturing of shale formations, or fracking. Shale formations full of gas keep turning up across the country, storage reservoirs are close to full and companies are now starting to try to export the excess gas.

The gas produced by oil drilling has only added to the surplus—and made it unlikely that it will end any time soon. Oil prices now top \$100 a barrel, giving energy companies ample incentive to expand drilling and keeping pressure on prices consumers pay at the pump. High oil prices effectively subsidize the production of otherwise unprofitable natural gas.

"That's what's being underestimated by a lot of people who expect the gas supply to fall precipitously," says Mark Papa, chief executive of EOG Resources Inc., one of the biggest independent oil-and-gas companies in the country.

Many experts predict rock-bottom natural-gas prices through at least 2013. "We're anticipating sustained low gas prices," says Andy Steinhubl, co-head of consultancy Bain & Co.'s North American oil and gas practice.

That is good news for consumers. More than half of American households use gas to heat their homes, and they can expect an 18% drop in the cost of staying warm this winter, according to federal forecasts. A home in the Northeast that uses natural gas can expect to spend \$1,023 this year, less than half the cost of heating with oil.

Inexpensive natural gas also is a boon for manufacturers and petrochemical producers. For the first time in nearly a decade, steel companies and plastics makers are building facilities in the U.S., taking advantage of the inexpensive fuel to compete globally.

Domestic explorers have little choice but to keep pumping. They have spent enormous sums leasing up prospective acreage in gas fields. Saddled with those leasing costs, the companies are watching operating costs rise.

Although the energy industry typically talks about gas wells and oil wells, most wells usually contain a mixture of oil, gas and other petroleum products. In fact, nearly one-quarter of all U.S. gas production comes from oil wells, according to the government.

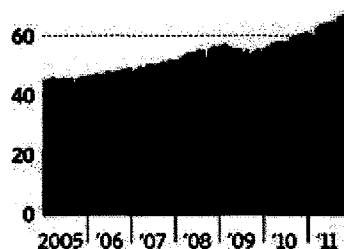
Moreover, many gas wells contain significant amounts of ethanes and other valuable liquids, which are sold separately and priced in relation to crude oil.

"Companies are making so much money on the oil and natural-gas liquids that gas is basically free," says Amy Myers Jaffe, director of Baker Institute Energy Forum, a policy think tank at Rice University in Houston. "They are saying to themselves: I am going to produce the gas regardless of what the price is, because I'm making money on the oil and liquids."

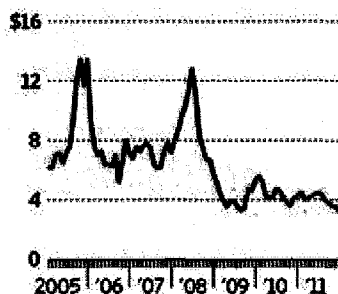
Pumping Up, Pricing Down

As onshore natural-gas production has risen...

80 billion cubic feet per day



...the price* per million BTUs has gone down.



*Monthly average settlement price on the continuous front-month contract.
Sources: Energy Information Administration; WSJ Market Data Group

To be sure, not everyone thinks inexpensive gas will last long. Jon Wolff, an analyst with International Strategy and Investment Group, says "nearly all U.S. gas drilling is uneconomic." He expects significant declines in gas production in Louisiana and Pennsylvania this year as financial hedges expire and joint-venture capital gets used up. He forecasts a rebound in gas prices to \$4.50 per million BTUs in the second half of

this year.

Chesapeake Energy Corp., which has drilled more U.S. gas wells in recent years than any other company, has said it will cut spending on such wells if prices remained at current levels.

"The market needs a rest," says Chief Executive Officer Aubrey McClendon. As soon as prices rebound, he says, "the industry will be back to drilling more aggressively than it is today."

Billions of dollars worth of existing exploration leases, however, limit how much such companies can ratchet back. Such leases generally require companies to drill at least some wells to keep the leases from expiring.

When Louisiana's Haynesville Shale was discovered in 2008, gas prices were over \$9 per million BTUs and companies rushed to lease as much acreage as possible. Landowners were paid up to \$30,000 an acre. The leases required companies to drill at least one well on each 640-acre block, usually within four years.

"If you don't drill, you will lose the lease—money put up and thrown away," says Don G. Briggs, president of the Louisiana Oil & Gas Association.

Another issue: some companies raised money from foreign energy companies on the condition that they use it to drill, a commitment that doesn't go away just because gas prices are now low.

Blair Thomas, chief executive officer of EIG Global Energy Partners, a private-equity firm that has invested heavily in domestic energy companies, says the industry will be dealing with lease expirations and drilling commitments for another year or two.

"Until that passes, the industry will continue to drill gas wells, whether they are economic or not," he says.

Over the longer term, an increase in the number of natural-gas-fired power plants could reduce the surplus of natural gas. New federal environmental rules require extensive upgrades to coal-fired power plants in order to reduce air emissions. Many coal plants are likely to be replaced with gas-fired generation.

In the meantime, gas production continues to rise. Daily gas production in South Texas' Eagle Ford oil field doubled last year and is expected to nearly double this year.

Goodrich isn't the only company opting to burn off natural gas. In the 12 months ended in August, the most recent data available, Texas approved 651 permits to burn off gas, up from 107 three years earlier.

The state says it requires drillers to hook up to pipelines eventually. In a few weeks, after a pipeline is upgraded, Goodrich plans to hook up the Dilley, Texas, well that is now flaring gas, and the gas glut might get a little bigger.

Write to Russell Gold at russell.gold@wsj.com and Ryan Dezember at ryan.dezember@dowjones.com

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12



U.S. Energy Information
Administration

NATURAL GAS

OVERVIEW DATA ANALYSIS & PROJECTIONS

GLOSSARY : FAQs >

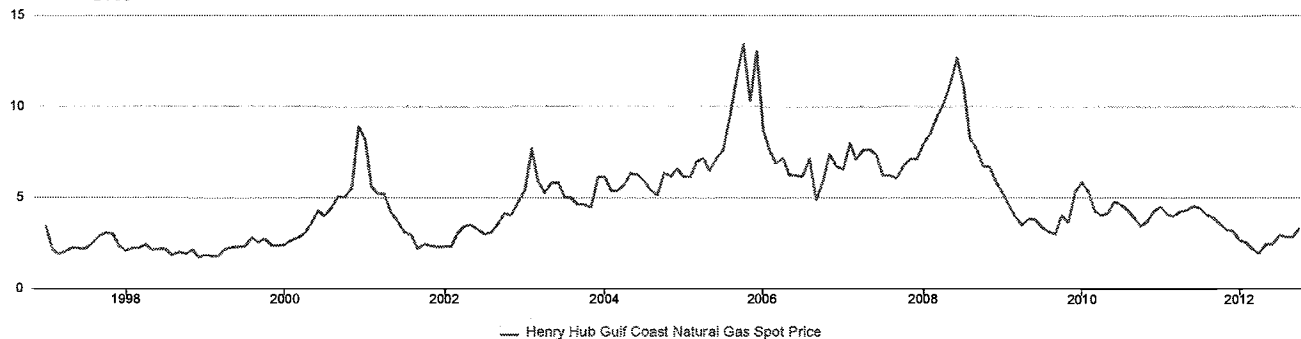
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Henry Hub Gulf Coast Natural Gas Spot Price

Dollars/Mil. BTUs



Source: U.S. Energy Information Administration

Chart Tools

no analysis applied

Henry Hub Gulf Coast Natural Gas Spot Price (Dollars/Mil. BTUs)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	3.45	2.15	1.89	2.03	2.25	2.20	2.19	2.49	2.88	3.07	3.01	2.35
1998	2.09	2.23	2.24	2.43	2.14	2.17	2.17	1.85	2.02	1.91	2.12	1.72
1999	1.85	1.77	1.79	2.15	2.26	2.30	2.31	2.80	2.55	2.73	2.37	2.36
2000	2.42	2.66	2.79	3.04	3.59	4.29	3.99	4.43	5.06	5.02	5.52	8.90
2001	8.17	5.61	5.23	5.19	4.19	3.72	3.11	2.97	2.19	2.46	2.34	2.30
2002	2.32	2.32	3.03	3.43	3.50	3.26	2.99	3.09	3.55	4.13	4.04	4.74
2003	5.43	7.71	5.93	5.26	5.81	5.82	5.03	4.99	4.62	4.63	4.47	6.13
2004	6.14	5.37	5.39	5.71	6.33	6.27	5.93	5.41	5.15	6.35	6.17	6.58
2005	6.15	6.14	6.96	7.16	6.47	7.18	7.63	9.53	11.75	13.42	10.30	13.05
2006	8.69	7.54	6.89	7.16	6.25	6.21	6.17	7.14	4.90	5.85	7.41	6.73
2007	6.55	8.00	7.11	7.60	7.64	7.35	6.22	6.22	6.08	6.74	7.10	7.11
2008	7.99	8.54	9.41	10.18	11.27	12.69	11.09	8.26	7.67	6.74	6.68	5.82
2009	5.24	4.52	3.96	3.50	3.83	3.80	3.38	3.14	2.99	4.01	3.66	5.35
2010	5.83	5.32	4.29	4.03	4.14	4.80	4.63	4.32	3.89	3.43	3.71	4.25
2011	4.49	4.09	3.97	4.24	4.31	4.54	4.42	4.06	3.90	3.57	3.24	3.17
2012	2.67	2.51	2.17	1.95	2.43	2.46	2.95	2.84	2.85	3.32		

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 11/15/2012
Next Release Date: 11/21/2012

Referring Pages:

■ [Natural Gas Futures Prices \(NYMEX\)](#)

13



1 of 1 DOCUMENT

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The U.S. Coal Review

March 12, 2012

SECTION: No. 1898

LENGTH: 299 words

HEADLINE: A sign of the times: 'Gas is coming into our turbines now, which is

BODY:

A sign of the times: 'Gas is coming into our turbines now, which is nothing' When you look at the paltry numbers that some utilities can bring in natural gas for generation these days, it's no wonder coal stockpiles keep mounting. The enormous inventories piling up at certain facilities aren't simply a result of low natural gas prices. Mild winter weather and meager power demand have also played a role in the lower coal consumption rates.

But when gas can be utilized at well below \$2.50 per million Btu, it's a serious detriment to coal burns. "Gas is coming into our turbines at \$2.30 now, which is nothing," a source with a Midwestern utility said. "The problem now is gas in storage has got to come out, so even if you cut production - which has been done at producing wells - the gas coming out of storage is going to keep prices low." Coal inventories across the utility's power plant system remain plentiful. "They are pretty healthy," the source said. "I'd say we still have a good 40 or so days on the ground. That will grow over the next couple of months because of outages we have planned for." The utility has run its simple-cycle gas turbines to help with morning heating load. "We had some on (March 7) for four hours because it was not worth bringing the coal unit on," the source said. "It was cheaper just to run the turbine. "We definitely will (continue to use more gas) because it has displaced our older, higher-cost coal units already. I think the gas price will stay under \$3.00 for the whole year. A lot of utilities with natural gas combined cycle will run those a lot more. That's not surprising.

"When you add the transportation of the coal - even if it's favorably priced coal - it probably delivers in over the price of gas."

LOAD-DATE: March 19, 2012

14

U.S. coal use falling fast as utilities switch to gas

By Jonathan Fahey, Associated Press

Updated 5/12/2012 9:15 PM



NEW YORK – America is shoveling coal to the sidelines.

The fuel that powered the U.S. from the industrial revolution into the iPhone era is being pushed aside as utilities switch to cleaner and cheaper alternatives.

The share of U.S. electricity that comes from coal is forecast to fall below 40% for the year, its lowest level since World War II. Four years ago, it was 50%. By the end of this decade, it is likely to be near 30%.

"The peak has passed," says Jone-Lin Wang, head of Global Power for the energy research firm IHS CERA.

Utilities are aggressively ditching coal in favor of natural gas, which has become cheaper as supplies grow. Natural gas has other advantages over coal: It produces far fewer emissions of toxic chemicals and gases that contribute to climate change, key attributes as tougher environmental rules go into effect.

Natural gas will be used to produce 30% of the country's electricity this year, up from 20% in 2008. Nuclear accounts for 20%. Hydroelectric, wind, solar and other renewables make up the rest.

The shift from coal is reverberating across Appalachia, where mining companies are laying off workers and cutting production. Utilities across the country are grappling with how to store growing piles of unused coal. And legal disputes are breaking out as they try to cancel

contracts and defer deliveries.

- Mining company Alpha Natural Resources of Bristol, Va., plans to produce 11.5 million fewer tons of coal this year, a decline of 11%, because so many customers have requested deferrals. The company has announced that 12 mining operations in Kentucky and West Virginia will be idled or slowed, and 353 jobs cut.

- Patriot Coal, a mining company based in St. Louis, closed a mine in Kentucky, idled several others in Kentucky and West Virginia, and has cut 1,000 jobs. The company's stock has fallen below \$2, down from nearly \$25 a year ago, and the company's CEO, Richard Whiting, was replaced at the end of May.

- GenOn, a wholesale power producer based in Houston, has invoked a legal clause typically used after natural disasters to try to stop suppliers from delivering more coal to already overloaded plants. "We just can't physically take it right now," says GenOn CEO Edward Muller.

Coal has dominated the U.S. power industry for so long because it's a cheap and abundant domestic resource. The U.S. is the world's second-largest coal producer after China, and it has the world's biggest reserves — enough to last more than 200 years.

Coal has also enjoyed strong political support because of the jobs it provides in mining and transportation. That helped coal thrive even as environmental concerns over mining practices and air quality grew.

Just five years ago, coal was flourishing in the U.S. With electricity demand and the price of natural gas both rising, coal was viewed as essential to keeping power costs under control. Utilities drew up plans to build dozens of coal-fired plants.

But around the same time, a revolution was under way in the natural gas industry. Drillers figured how to tap enormous deposits of previously inaccessible reserves. As supplies

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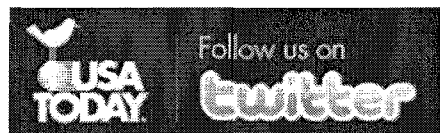
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grew and the price of natural gas plummeted, the ground shifted under the electric-power industry.

Now coal is being beaten at its own game. Natural gas has become a cheap and abundant domestic resource, too. And it is more environmentally friendly.

Power plants that burn coal produce more than 90 times as much sulfur dioxide, five times

as much nitrogen oxide and twice as much carbon dioxide as those that run on natural gas, according to the Government Accountability Office, the regulatory arm of Congress. Sulfur dioxide causes acid rain; nitrogen oxides cause smog; and carbon dioxide is a so-called greenhouse gas that traps heat in the atmosphere.

A pair of clean air rules enacted by the Environmental Protection Agency over the past year tightens limits on power-plant emissions of sulfur dioxide and nitrogen dioxide, and place new limits on mercury, a poison found in coal. This will force between 32 and 68 of the dirtiest and oldest coal plants in the country to close over the next three years as the rules go into effect, according to an AP survey of power plant operators conducted late last year.

Coal was hit with a potentially bigger environmental blow in March when the EPA issued guidelines that could limit greenhouse gas emissions from new power plants as early as 2013. Once the guidelines go into effect, no coal plants will be built unless utilities can develop a cost-effective way to capture carbon dioxide, analysts say. That technology has been slow to develop and is very expensive.

"Even without the EPA rules, coal is not really competitive," Wang says.

Coal executives are hardly giving up. Nick Deluliis, President of Consol Energy, a coal and natural gas producer based in Canonsburg, Pa., doubts the EPA's restrictions on greenhouse gases will survive long term because of the economic harm he says they will inflict.

Consol and other U.S. coal companies hope to be able to keep mines active by exporting more of the country's huge reserves. Last year U.S. coal exports hit a record 107 million short tons. High grade coal that is used to make steel is in particular demand in developing countries such as China, India and Brazil.

Deluliis says the price of natural gas will rebound over time and that coal will once again account for half the nation's electricity. "This is a cycle," he says.

The futures price of natural gas hit a 10-year low of \$1.91 per thousand cubic feet in April. It closed Monday at \$2.22 but would have to more than double from there to convince utilities that have a choice of fuels to return to coal whenever possible.

Utilities are forecast to burn 796 million tons of coal this year, a 14% decline from last year and the fewest tons since 1992, according to Energy Department data.

Demand for coal has fallen even faster than the environmentalists who have been lobbying against coal had anticipated.

Bruce Nilles, director of the Sierra Club's Beyond Coal campaign, says the shift was accelerated by the low price of natural gas. That, along with tougher environmental rules and alternatives such as wind and solar will keep the pressure on coal. "We won't go backwards," he says.

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15

Table 8.2a Electricity Net Generation: Total (All Sectors), Selected Years, 1949-2011
(Sum of Tables 8.2b and 8.2d; Billion Kilowatthours)

Year	Fossil Fuels				Hydro- electric Pumped Storage ⁵	Renewable Energy						Other ¹⁰	Total		
	Coal ¹	Petroleum ²	Natural Gas ³	Other Gases ⁴		Total	Nuclear Electric Power	Conventional Hydroelectric Power ⁶	Biomass		Geo- thermal			Solar/PV ⁹	Wind
									Wood ⁷	Waste ⁸					
1949	135.5	28.5	37.0	NA	201.0	0.0	94.8	0.4	NA	NA	NA	NA	95.2	NA	296.1
1950	154.5	33.7	44.6	NA	232.8	0	100.9	.4	NA	NA	NA	NA	101.3	NA	334.1
1955	301.4	37.1	95.3	NA	433.8	0	116.2	.3	NA	NA	NA	NA	116.5	NA	550.3
1960	403.1	48.0	158.0	NA	609.0	.5	149.4	.1	NA	(s)	NA	NA	149.6	NA	789.2
1965	570.9	64.8	221.6	NA	857.3	3.7	197.0	.3	NA	.2	NA	NA	197.4	NA	1,058.4
1970	704.4	184.2	372.9	NA	1,261.5	21.8	251.0	.1	.2	.2	NA	NA	251.8	NA	1,535.1
1975	852.8	289.1	299.8	NA	1,441.7	172.5	303.2	(s)	.2	3.2	NA	NA	306.6	NA	1,920.8
1976	944.4	320.0	294.6	NA	1,559.0	191.1	286.9	.1	.2	3.6	NA	NA	290.8	NA	2,040.9
1977	985.2	358.2	305.5	NA	1,648.9	250.9	223.6	.3	.2	3.6	NA	NA	227.7	NA	2,127.4
1978	975.7	365.1	305.4	NA	1,646.2	276.4	283.5	.2	.1	3.0	NA	NA	286.8	NA	2,209.4
1979	1,075.0	303.5	329.5	NA	1,708.0	255.2	283.1	.3	.2	3.9	NA	NA	287.5	NA	2,250.7
1980	1,161.6	246.0	346.2	NA	1,753.8	251.1	279.2	.3	.2	5.1	NA	NA	284.7	NA	2,289.6
1981	1,203.2	206.4	345.8	NA	1,755.4	272.7	283.8	.2	.1	5.7	NA	NA	289.9	NA	2,298.0
1982	1,192.0	146.8	305.3	NA	1,644.1	282.8	312.4	.2	.1	4.8	NA	NA	317.5	NA	2,244.4
1983	1,259.4	144.5	274.1	NA	1,678.0	293.7	335.3	.2	.2	6.1	NA	(s)	341.7	NA	2,313.4
1984	1,341.7	119.8	297.4	NA	1,758.9	327.6	324.3	.5	.4	7.7	(s)	(s)	332.9	NA	2,419.5
1985	1,402.1	100.2	291.9	NA	1,794.3	383.7	284.3	.7	.6	9.3	(s)	(s)	295.0	NA	2,473.0
1986	1,385.8	136.6	248.5	NA	1,770.9	414.0	294.0	.5	.7	10.3	(s)	(s)	305.5	NA	2,490.5
1987	1,463.8	118.5	272.6	NA	1,854.9	455.3	282.9	.8	.7	10.8	(s)	(s)	265.1	NA	2,575.3
1988	1,540.7	148.9	252.8	NA	1,942.4	527.0	226.1	.9	.7	10.3	(s)	(s)	238.1	NA	2,707.4
1988 ¹¹	1,583.8	164.4	352.6	7.9	2,108.6	529.4	272.0	27.2	9.2	14.6	.3	2.1	325.3	3.8	2,967.1
1990	1,594.0	126.5	372.8	10.4	2,103.6	576.9	292.9	32.5	13.3	15.4	.4	2.8	357.2	3.6	3,037.8
1991	1,590.6	119.8	381.6	11.3	2,103.3	612.6	289.0	33.7	15.7	16.0	.5	3.0	357.8	4.7	3,073.8
1992	1,621.2	100.2	404.1	13.3	2,138.7	618.8	253.1	36.5	17.8	16.1	.4	2.9	326.9	3.7	3,083.9
1993	1,690.1	112.8	414.9	13.0	2,230.7	610.3	280.5	37.6	18.3	16.8	.5	3.0	356.7	3.5	3,197.2
1994	1,690.7	105.9	460.2	13.3	2,270.1	640.4	260.1	37.9	19.1	15.5	.5	3.4	336.7	3.7	3,247.5
1995	1,709.4	74.6	496.1	13.9	2,293.9	673.4	310.8	36.5	20.4	13.4	.5	3.2	384.8	4.1	3,353.5
1996	1,795.2	81.4	455.1	14.4	2,346.0	674.7	347.2	36.8	20.9	14.7	.5	3.3	423.0	3.6	3,444.2
1997	1,845.0	92.6	479.4	13.4	2,430.3	628.6	356.5	36.9	21.7	14.7	.5	3.2	433.6	3.6	3,492.2
1998	1,873.5	128.8	531.3	13.5	2,547.1	673.7	323.3	36.3	22.4	14.8	.5	3.0	400.4	3.6	3,620.3
1999	1,881.1	118.1	556.4	14.1	2,569.7	728.3	319.5	37.0	22.6	14.8	.5	3.5	399.0	4.0	3,694.8
2000	1,966.3	111.2	601.0	14.0	2,692.5	753.9	275.6	37.6	23.1	14.1	.5	5.6	356.5	4.8	3,802.1
2001	1,904.0	124.9	639.1	9.0	2,677.0	768.8	217.0	35.2	14.5	13.7	.5	6.7	287.7	11.9	3,736.6
2002	1,933.1	94.6	691.0	11.5	2,730.2	780.1	264.3	38.7	15.0	14.5	.6	10.4	343.4	13.5	3,858.5
2003	1,973.7	119.4	649.9	15.6	2,758.6	783.7	275.8	37.5	15.8	14.4	.6	11.2	355.3	14.0	3,883.2
2004	1,978.3	121.1	710.1	15.3	2,824.8	788.5	288.4	38.1	15.4	14.8	.6	14.1	351.5	14.2	3,970.6
2005	2,012.9	122.2	761.0	13.5	2,909.5	782.0	270.3	38.9	15.4	14.7	.6	17.8	357.7	12.8	4,056.4
2006	1,990.5	64.2	816.4	14.2	2,865.3	787.2	289.2	38.8	16.1	14.6	.5	26.6	385.8	13.0	4,064.7
2007	2,016.5	65.7	896.6	13.5	2,992.2	806.4	247.5	39.0	16.5	14.6	.6	34.4	352.7	12.2	4,156.7
2008	1,985.8	46.2	883.0	11.7	2,926.7	806.2	254.8	37.3	17.7	14.8	.9	55.4	380.9	11.8	4,119.4
2009	1,755.9	38.9	921.0	10.6	2,726.5	793.9	273.4	36.1	18.4	15.0	.9	73.9	417.7	11.9	3,950.3
2010	R1,847.3	R37.1	R987.7	R11.3	R2,883.4	R807.0	R260.2	R37.2	R18.9	R15.2	R12	R94.7	R427.4	R12.9	R4,125.1
2011 ^P	1,734.3	28.2	1,016.6	11.3	2,790.3	790.2	325.1	36.9	19.8	16.7	1.8	119.7	520.1	11.1	4,105.7

¹ Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and coal synton.

² Distillate fuel oil, residual fuel oil, petroleum coke, jet fuel, kerosene, other petroleum, and waste oil.

³ Natural gas, plus a small amount of supplemental gaseous fuels.

⁴ Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

⁵ Pumped storage facility production minus energy used for pumping.

⁶ Through 1989, hydroelectric pumped storage is included in "Conventional Hydroelectric Power."

⁷ Wood and wood-derived fuels.

⁸ Municipal solid waste from biogenic sources, landfill gas, sludge waste, agricultural byproducts, and other biomass. Through 2000, also includes non-renewable waste (municipal solid waste from non-biogenic sources, and tire-derived fuels).

⁹ Solar thermal and photovoltaic (PV) energy.

¹⁰ Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, miscellaneous technologies, and, beginning in 2001, non-renewable waste (municipal solid waste from non-biogenic sources, and tire-derived

fuels).

¹¹ Through 1988, all data except hydroelectric are for electric utilities only; hydroelectric data through 1988 include industrial plants as well as electric utilities. Beginning in 1989, data are for electric utilities, independent power producers, commercial plants, and industrial plants.

R- Revised. P- Preliminary. NA=Not available. (s)=Less than 0.05 billion kilowatthours.

Notes: • See Note 1, "Coverage of Electricity Statistics," at end of section. • Totals may not equal sum of components due to independent rounding.

Web Pages: • See <http://www.eia.gov/totalenergy/data/monthly/#electricity> for updated monthly and annual data. • See <http://www.eia.gov/totalenergy/data/annual/#electricity> for all annual data beginning in 1949. • See <http://www.eia.gov/electricity/> for related information.

Sources: • 1949-1988—Table 8.2b for electric power sector, and Table 8.1 for industrial sector. • 1989 forward—Tables 8.2b and 8.2d.

16



1 of 1 DOCUMENT

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St. Louis Post-Dispatch (Missouri)

April 8, 2012 Sunday
FOURTH EDITION

SECTION: BUSINESS; Pg. E1

LENGTH: 1100 words

HEADLINE: Constraints Cool Down Coal Sliding demand is blamed on lower natural gas prices, increased regulation.

BYLINE: BY JEFFREY TOMICH o jtomich@post-dispatch.com > 314-340-8320

DATELINE: 0

BODY:

There's no doubt King Coal still rules the energy world. Power plants burned more than 900 million tons of the black rock last year, generating electricity to run factories, cool homes and charge iPhones.

But domestic demand has tailed off gradually since 2007. This year, one of the mildest winters on record and the continued collapse of natural gas prices have accelerated the decline.

Coal's share of total U.S. electricity generation fell below 40 percent in the final two months of last year - the first time market share has slipped to that level since Jimmy Carter was in the White House, according to data from the Energy Information Administration. Meanwhile, coal producers are idling mines and lowering earnings forecasts - a fact reflected in beaten down stock prices for the entire sector.

The collective market value of publicly traded coal companies based in the St. Louis area - Peabody Energy Corp., Arch Coal Inc. and Patriot Coal Corp. - has fallen by billions of dollars from last year. Arch Coal, for instance, closed at \$10.15 on Thursday, the lowest point since November 2008, and less than a third of its value just a year ago. Peabody and Patriot have fallen hard, too.

Of course, coal markets have ebbed and flowed for decades in sympathy with changes in weather and the economy. And the industry has been counted out more than once before. But a combination of new dynamics make a recovery for the domestic coal industry more challenging - and uncertain - this time.

"Commodities and energy go through these cycles," said Michael Dudas, a coal analyst at Stern, Agee and Leach Inc. in New York. "But there is an element of structural change that's occurring in the utility sector driven by regulation

Constraints Cool Down Coal Sliding demand is blamed on lower natural gas prices, increased regulation. St. Louis Post-Dispatch (Missouri) April 8, 2012 Sunday

and, secondly, lower natural gas prices."

Domestic natural gas production has surged in recent years as advances in hydraulic fracturing, or fracking, and horizontal drilling technologies allow producers to access reserves trapped in shale rock formations. Fracking involves injecting a mix of sand, water and chemicals deep underground to break apart the rock and release the gas.

The increase in output is reflected in a record amount of gas in storage and a collapse in prices. Gas inventories as of March 30 totaled 2.5 trillion cubic feet, a record for this time of year when storage levels are typically depleted. And natural gas futures on the New York Mercantile Exchange, which peaked at \$14 per thousand cubic feet in mid-2008, fell to a decade-low of \$2.09 per thousand cubic feet this week.

Natural gas is the main competitor to coal as a fuel for electricity generation, and it - much more than renewable energy technologies such as wind and solar power - are stealing market share from coal.

Gas prices "have been pretty unrelenting in their decline to the point that some higher-cost coal-mining regions find themselves up against a fuel that's become pretty abundant," said Paul Forward, a coal analyst at Stifel Nicolaus & Co. in Baltimore.

The coal industry, however, sees prices gravitating up toward \$4 in the months to come. That's cheap by recent standards, but a level at which coal from the Powder River Basin competes well, said Deck Slone, an Arch Coal vice president.

"We don't view the current gas prices as being sustainable longer term," he said.

Also clouding the longer-term outlook for the coal sector is a series of pending and proposed rules aimed at slashing pollution from coal-fired power plants. The regulations are welcomed by environmentalists as long overdue. Slone described them as "ill-advised" and said they threaten to raise energy prices.

Officials at Patriot could not be reached for comment Friday.

The Environmental Protection Agency issued the most recent of these proposed rules two weeks ago. The standard would, for the first time, establish emissions limits for carbon pollution from new power plants - 1,000 pounds of carbon dioxide per megawatt-hour of electricity generated.

The combination of a tepid economy, depressed power markets and costs of meeting tougher environmental regulations have already prompted utilities including Ameren Corp. to shutter older, dirtier and less efficient coal-fired power plants. While the new EPA proposal wouldn't affect plants that are already permitted or are being built now, including the massive Prairie State plant near Lively Grove, Ill., some observers believe it would not be cost-effective for utilities to build new coal-powered plants with today's technology.

"If somehow these regulations eliminate the potential for new power plants to use coal, then it does force coal companies to redirect their focus to areas where demand is growing," Forward said.

Those growing markets are, in particular, China and India. They're the reason why coal companies including Arch and Peabody are looking to expand coal export capacity in the U.S. Peabody, the largest U.S. coal producer, has also invested billions of dollars in Australia to more directly tap Asia's appetite for energy.

Meantime, producers are coping with a bleak near-term market outlook, thanks to the mild winter and a pullback in international demand for so-called metallurgical coal used to make steel.

In the U.S., coal stockpiles at power plants continue to swell. Analysts see inventories exceeding a near-record 200 million tons nationwide entering summer, and some utilities may try to defer deliveries until 2013 or even sell some coal for export overseas.

Constraints Cool Down Coal Sliding demand is blamed on lower natural gas prices, increased regulation. St. Louis Post-Dispatch (Missouri) April 8, 2012 Sunday

Producers have already made production cuts, including steep cuts in the massive mines of the Powder River Basin of northeast Wyoming. Analysts see more curtailments to come, especially in higher cost areas where coal seams are thinner, like central Appalachia.

But analysts believe the sell-off in coal shares, particularly certain companies, may have already gone too far. Coal demand is projected to rebound somewhat in 2013, and no matter how cheap natural gas remains, there's only so much coal gas can displace in coming years.

In fact, the Energy Information Administration estimates coal will stay at near 40 percent market share for the next two decades, and exports are projected to continue rising.

"There's certainly a lot of fear and nervousness attached to (coal stocks) because of the shocking drop in natural gas and the slowdown in met coal pricing abroad," Dudas said.

"But current share prices are discounting much lower ... (coal) prices and volumes than I think is warranted."

St. Louis Area Coal Stocks

Company April 7, 2011 April 6, 2012 % Change

Arch Coal \$34.23 \$10.15 -70.3%

Peabody Energy \$68.05 \$28.27 -58.5%

Patriot Coal \$26.35 \$5.70 -78.4%

GRAPHIC: Peter Newcomb o Bloomberg Coal Train cars filled with coal sit on railroad tracks near St. Louis in 2007. Andrew Harrer o Bloomberg EPA The agency's proposals aim to slash emissions from new power plants. Julia Schmalz o Bloomberg Natural Gas Hydraulic fracturing and changes in drilling have increased natural gas production. Graphics: Natural Gas Gaining Coal Losing Steam

LOAD-DATE: April 9, 2012

17

GAO

Report to the Chairman, Committee on
Commerce, Science, and
Transportation, U.S. Senate

July 2012

EPA REGULATIONS AND ELECTRICITY

Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges





Highlights of GAO-12-635, a report to the Chairman, Committee on Commerce, Science, and Transportation, U.S. Senate

July 2012

EPA REGULATIONS AND ELECTRICITY

Better Monitoring by Agencies Could Strengthen Efforts to Address Potential Challenges

Why GAO Did This Study

EPA recently proposed or finalized four regulations affecting coal-fueled electricity generating units, which provide almost half of the electricity in the United States: (1) the Cross-State Air Pollution Rule; (2) the Mercury and Air Toxics Standards; (3) the proposed Cooling Water Intake Structures regulation; and (4) the proposed Disposal of Coal Combustion Residuals regulation. Power companies may retrofit or retire some units in response to the regulations. EPA estimated two of the regulations would prevent thousands of premature deaths and generate \$160-\$405 billion in annual benefits. Some stakeholders have expressed concerns that these regulations could increase electricity prices and compromise reliability—the ability to meet consumers' demand. FERC and others have oversight over electricity prices and reliability. DOE can order a generating unit to run in certain emergencies.

GAO was asked to examine: (1) actions power companies may take in response to these regulations; (2) their potential electricity market and reliability implications; and (3) the extent to which these implications can be mitigated. GAO reviewed agency documents, selected studies, and interviewed stakeholders.

What GAO Recommends

GAO recommends, among other things, that FERC, DOE, and EPA take additional steps to monitor industry's progress in responding to the regulations. DOE and EPA agreed with this recommendation, and FERC disagreed with this and another recommendation. GAO continues to believe that it is important for FERC to take the recommended actions.

View GAO-12-635. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov or David Trimble at (202) 512-3841 or trimbled@gao.gov.

What GAO Found

It is uncertain how power companies may respond to four key Environmental Protection Agency (EPA) regulations, but available information suggests companies may retrofit most coal-fueled generating units with controls to reduce pollution, and that 2 to 12 percent of coal-fueled capacity may be retired. Some regions may see more significant levels of retirements. For example, one study examined 11 states in the Midwest and projected that 18 percent of coal-fueled capacity in that region could retire. EPA and some stakeholders GAO interviewed stated that some such retirements could occur as a result of other factors such as lower natural gas prices, regardless of the regulations. Power companies may also build new generating units, upgrade transmission systems to maintain reliability, and increasingly use natural gas to produce electricity as coal units retire and remaining coal units become somewhat more expensive to operate.

Available information suggests these actions would likely increase electricity prices in some regions. Furthermore, while these actions may not cause widespread reliability concerns, they may contribute to reliability challenges in some regions. Regarding prices, the studies GAO reviewed estimated that increases could vary across the country, with one study projecting a range of increases from 0.1 percent in the Northwest to an increase of 13.5 percent in parts of the South more dependent on electricity generated from coal. According to EPA officials, the agency's estimates of price increases would be within the historical range of price fluctuations, and projected future prices may be below historic prices. Regarding reliability, these actions are not expected to pose widespread concerns but may contribute to challenges in some regions. EPA and some stakeholders GAO interviewed indicated that these actions should not affect reliability given existing tools. Some other stakeholders GAO interviewed identified potential reliability challenges. Among other things, it may be difficult to schedule and complete all retrofits to install controls and to resolve all potential reliability concerns associated with retirements within compliance deadlines.

Existing tools could help mitigate many, though not all, of the potential adverse implications associated with the four EPA regulations, but the Federal Energy Regulatory Commission (FERC), Department of Energy (DOE), and EPA do not have a joint, formal process to monitor industry's progress in responding to the regulations. Some tools, such as state regulatory reviews to evaluate the prudence of power company investments, may address some potential price increases. Furthermore, tools available to industry and regulators, as well as certain regulatory provisions, may address many potential reliability challenges. However, because of certain limitations, these tools may not fully address all challenges where generating units needed for reliability are not in compliance by the deadlines. FERC, DOE, and EPA have responsibilities concerning the electricity industry, and they have taken important first steps to understand these potential challenges by, for example, informally coordinating with power companies and others about industry's actions to respond to the regulations. However, they have not established a formal, documented process for jointly and routinely monitoring industry's progress and, absent such a process, the complexity and extent of potential reliability challenges may not be clear to these agencies. This may make it more difficult to assess whether existing tools are adequate or whether additional tools are needed.

but did not issue a regulation under section 112.¹⁶ In 2005, EPA reversed this finding and finalized a regulation under section 111 of the Clean Air Act regulating mercury emissions from certain electricity generating units, which a federal court later struck down. Pursuant to a settlement agreement to resolve a lawsuit for failing to meet the statutory deadline for issuing a section 112 regulation, EPA published the final MATS regulations in February 2012.¹⁷ Among other things, MATS establishes numerical emissions limitations for mercury, filterable particulate matter (as a surrogate for all toxic nonmercury metal pollutants), and hydrogen chloride (as a surrogate for all toxic acid gas pollutants) at certain new and existing generating units. All of the numerical limitations applicable to existing units except one are set at the average emissions limitation achieved by the best performing 12 percent of existing sources.¹⁸ Generating units would have 3 years, until April 2015, to comply with MATS and could receive up to a 1-year extension from permitting authorities (typically state or local authorities), if necessary for the installation of controls. EPA also outlined a mechanism to allow units that are needed to address specific and documented reliability concerns to receive Clean Air Act administrative orders to provide up to an additional

¹⁶Specifically, the finding was regarding coal- and oil-fueled electric utility steam generating units. EPA also found that regulation of hazardous air pollutants emissions from natural gas-fueled electric utility steam generating units was not appropriate or necessary.

¹⁷The statutory deadline for issuing section 112 regulations for hazardous air pollutants from coal- and oil-fueled electric utility steam generating units was 2 years from the date on which the units were listed as sources of hazardous air pollutants subject to regulation, which was December 20, 2000. In 2008, EPA settled a lawsuit alleging that it had failed to promulgate emissions standards under section 112 for hazardous air pollutants from coal- and oil-fueled electric utility steam generating units by agreeing to sign a final regulation by the end of 2011.

¹⁸Specifically, MATS applies to electricity utility steam generating units that have over 25 MW capacity and meet other requirements. MATS also establishes work practice standards in lieu of numerical emissions limitations for organic hazardous air pollutants and for limited use oil-fueled electric utility steam generating units as defined in the final regulation.

Disposal of Coal Combustion
Residuals: CCR

year to come into compliance.¹⁹ EPA estimates that the final standards would reduce mercury emissions from coal-fueled electricity generating units by 75 percent and reduce hydrogen chloride emissions by 88 percent. EPA estimated the benefits of MATS would be \$39 to \$96 billion with costs of \$10.2 billion in 2016. Petitions for review of MATS have been filed in the U.S. Court of Appeals for the D.C. Circuit, but the court has not yet issued a ruling. Depending on how the court rules, MATS may change.

Burning coal to produce electricity creates combustion residuals, such as coal ash, which represent one of the largest waste streams in the United States. These residuals contain contaminants like mercury, cadmium, and arsenic that are associated with cancer and various other serious health effects. Coal combustion residuals can be disposed of wet (mixed with water) in large surface impoundments, or dry in landfills.²⁰ EPA has stated that many landfills and impoundments lack liners and groundwater monitoring systems, and without proper protections, contaminants can leach into groundwater and migrate to drinking water sources, posing significant public health concerns.²¹

The Resource Conservation and Recovery Act authorizes EPA to establish regulations for the treatment, storage, and disposal of hazardous waste and to establish national minimum criteria for the

¹⁹EPA's Office of Enforcement and Compliance Assurance issued a policy memorandum describing its intended approach regarding the use of Clean Air Act Section 113(a) administrative orders for sources that must operate in noncompliance with MATS for up to a year to address a specific and documented reliability concern. See: EPA, "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard" (available at <http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf>).

²⁰Some coal combustion residuals have beneficial uses; for example, they can be used in the manufacture of such construction materials as concrete or wallboard. According to EPA documentation, about 37 percent of coal combustion residuals are used beneficially. EPA did not propose to regulate the beneficial use of coal combustion residuals, though some industry officials have expressed concerns that designating residuals as hazardous could negatively impact beneficial uses.

²¹Furthermore, accidents—such as the 2008 breach of a dike at a Tennessee Valley Authority coal plant impoundment—can result in large-scale releases of coal combustion residuals. The 2008 accident caused the release of 5.4 million cubic yards of coal ash into a nearby river and covered more than 300 acres with coal ash; it also damaged homes, roads, rail lines, and utilities.

disposal of nonhazardous solid waste to protect human health and the environment. In June 2010, to address risks from the disposal of coal combustion residuals generated at electricity generating units, EPA proposed CCR to regulate coal combustion residuals for the first time.²² EPA co-proposed two alternative regulations. Under the first, EPA would list residuals as a special waste and regulate them as a hazardous waste by establishing requirements for their management from generation to disposal. Under the second option, EPA would regulate coal combustion residuals as nonhazardous solid waste and establish national minimum standards for their disposal in surface impoundments or landfills. Regulation as a special waste would occur through a federal or authorized state permitting program with requirements for its storage, transport, and disposal, among other things. Regulation as a special waste would also allow for federal enforcement. Regulation as a nonhazardous solid waste would not require the establishment of a permit program and would not be federally enforceable. Instead, states or private parties could bring lawsuits against alleged violators. EPA estimated the annualized benefits of its special waste option would be \$207 to \$1,342 million with \$1,549 million in annualized costs and that the nonhazardous waste option would generate annualized benefits of \$88 to \$596 million with \$606 million in annualized costs.²³ EPA does not have a schedule for issuing a final CCR regulation.

Damage to Aquatic Life: 316(b)

Coal and other types of electricity generating units often draw in large volumes of water from nearby rivers, lakes, or oceans to use for cooling, which can damage aquatic life. Thermoelectric generating units are the largest water use category by sector, using 201 billion gallons per day in

²²The act exempted waste generated primarily from the combustion of coal or other fossil fuels—generally known as coal combustion residuals—from regulation as hazardous waste until EPA conducted a study and determined whether regulation as a hazardous waste was warranted. After issuing the required study (in two parts, the first in 1988 and the second in 1999), EPA determined in 1993, and again in 2000, that regulation of coal combustion residuals as a hazardous waste was unwarranted.

²³These estimates refer to EPA's scenario assuming CCR would not change the beneficial use of coal combustion residuals. EPA also estimated benefits for two other scenarios. The scenario EPA considers to be the most likely assumes that CCR would increase beneficial use, and EPA estimated the annualized benefits of its special waste option would be \$6,526 to \$7,646 million and that the nonhazardous waste option would generate annualized benefits of \$2,616 to \$3,125 million. In a scenario where CCR decreases beneficial use, EPA estimated there would be negative annualized benefits for its special waste option (additional costs) of \$17,270 to \$16,149 million, and that the nonhazardous waste option would generate annualized benefits of \$88 to \$596 million.

2005, the most recent year for which data were available. Depending on how a generating unit's cooling system is designed, drawing in water for cooling can result in fish and other aquatic life being impinged—trapped—against intake screens used to filter out solid matter, as well as entrained—drawn into—the generating unit with the cooling water.²⁴ According to EPA, generating units kill hundreds of billions of aquatic organisms in U.S. waters each year, including fish, crustaceans, marine mammals, and other aquatic life.

Section 316(b) of the Clean Water Act requires EPA to establish standards for cooling water intake structures that reflect the best available technology for minimizing adverse environmental impact. To implement section 316(b), EPA has issued several regulations, including a regulation in 2004 that governed existing power plants with a large flow water intake.²⁵ However, a federal appeals court struck down the 2004 regulation. Following an appeal to the Supreme Court and settlement of other lawsuits related to the rulemaking, EPA proposed a regulation covering certain existing power plants and other facilities on April 20, 2011. Regarding impingement, the proposal would establish fish mortality requirements reflecting the best available technology based on the performance of either (1) modified traveling screens—which capture and safely return fish to water bodies—or equivalent technology or (2) reduction of the facility's water intake velocity—which would allow fish and other organisms to move away from the intake structure. Regarding entrainment, the proposal would require permitting authorities to follow a process prescribed in the regulation to determine compliance deadlines and the best available technology for entrainment controls on a site-specific basis based on consideration of several specific factors. These factors include the quantified and qualitative social benefits and costs of available control options and impacts on electricity reliability. EPA estimates that approximately 45 percent of the nation's generating

²⁴Using water for cooling may also result in significant water use, and the discharge of cooling water that has been warmed from the plant process can raise the temperature of receiving water bodies.

²⁵EPA first issued a regulation implementing section 316(b) in 1976, but that regulation was struck down by a federal appeals court in 1979. EPA has issued two other regulations implementing section 316(b) that are currently in effect: the Phase I regulation that governs new power plants and manufacturing facilities and the Phase III regulation that governs new offshore oil and gas facilities.

capacity would be affected by the proposed regulation.²⁶ As a result of regulating cooling water intake structures, EPA estimates increased harvests in recreational and commercial fisheries, improved ecosystem function, and reduced harm to threatened and endangered species, among other benefits. EPA estimated the annualized benefits of its proposed regulation to be \$18 million with costs of \$397 million. EPA is required by a settlement agreement to sign a final regulation no later than July 27, 2012.

Planning and Day-to-Day Actions Involved in Maintaining Electric Reliability

Electric reliability refers to the ability to meet the needs of end-use customers even when unexpected generating equipment failures or other factors affect the electricity system.²⁷ Reliability challenges can arise in multiple ways:

- *Resource adequacy challenges.* These arise when there are inadequate resources—generation, transmission, and others—to meet the electricity needs of end-use customers. To avoid resource adequacy challenges, system planners typically take steps to ensure that generating capacity exceeds the maximum expected demand by a certain margin, referred to as a “reserve margin.”
- *System security challenges.* These arise because of a disturbance, such as an electrical short, or the loss of a system component, such as a generating unit that is needed at a specific location to maintain the electricity grid’s voltage and frequency or to help restart the electricity system in the case of a blackout. To avoid system security challenges, system operators make real-time changes in the operation of the electricity system, for example, by increasing or decreasing the amount of electricity generated in particular locations

²⁶This proposed regulation applies to existing power generating and manufacturing facilities, as well as new units at existing facilities, which have a design intake flow of more than 2 million gallons of water per day and use at least 25 percent of the water withdrawn exclusively for cooling purposes. The proposed regulation would also apply to oil-fueled, gas-fueled, and nuclear generating units that meet those requirements. EPA estimated that 559 fossil fuel electricity generating facilities would be subject to this regulation.

²⁷We use the term electricity grid to refer to an interconnected regional network of transmission lines and the term electricity system to refer to the electricity grid together with generating units used to provide electricity to customers.

18

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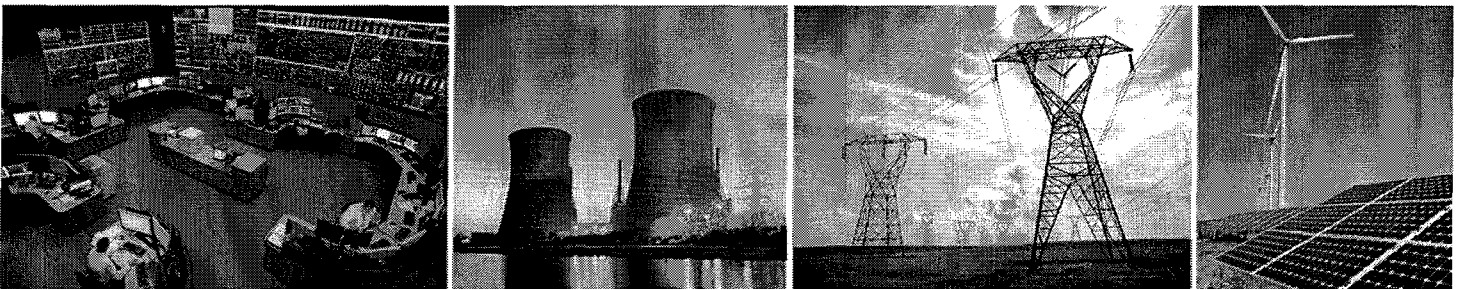
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Potential Impacts of Future Environmental Regulations

Extracted from the 2011 Long-Term
Reliability Assessment

November 2011

RELIABILITY | ACCOUNTABILITY



Potential Impacts of Future Environmental Regulations

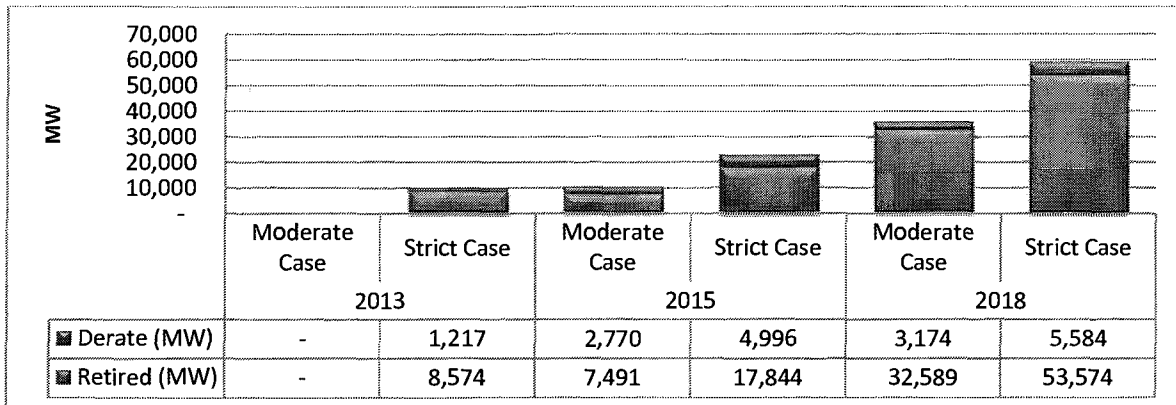
Summary

In the United States (U.S.), the Environmental Protection Agency (EPA) is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule (CCR rule), the proposed Mercury and Air Toxics Standards for Utilities, (Utility Air Toxics rule) the proposed Cooling Water Intake Structures § 316(b) rule (316(b) rule) , and the final Cross-State Air Pollution Rule (CSAPR).¹¹⁹ In October 2010, NERC released an assessment of the potential resource adequacy effects of precursors to these proposed rules using 2009 bulk power system resource plan projections and demand forecasts. This 2010 assessment, entitled: *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010 NERC EPA Assessment), provided an independent and integrated preliminary perspective on the potential for the accelerated retirement of fossil-fired units under assumptions based on earlier versions of the rules or expectations about what the rules would contain.

While it is not possible to determine the exact impacts of these regulations until each regulation is finalized, many studies have been performed which attempt to predict the effects of these regulations as well as other economic factors driving retirements of electric generating units. This assessment, which is included as a companion study in this *2011 Long-Term Reliability Assessment*, updates the resource and demand forecasts used in the 2010 NERC EPA Assessment with the 2011 forecasts. Additionally, NERC revised the assumptions applied in its 2010 NERC EPA Assessment, taking into account new information that was not available at the time that report was prepared. Specifically, in this update, NERC used updated assumptions determined from proposed rules, as well as other viewpoints on how the rule will ultimately be carried out (*i.e.*, how states may implement regulations), to determine potential resource adequacy impacts. The expected retirements of electric generators are driven by many economic factors, not simply the cost of pollution control equipment.

While these updated results are provided for informational purposes to inform stakeholders and policy makers, they do not represent NERC's judgment on which units can, should, or will be retired. The two cases assessed are based on scenarios that represent a range of potential outcomes. Based on the results of the Moderate Case, 36 GW of incremental capacity in coal, oil, and gas-fired generation is identified for either retirement or for capacity reductions to support additional station loads (deratings) by 2018 (Figure 54). In the Strict Case, capacity reductions amount to approximately 59 GW. Of most important, however, are the retirements that may occur, as well as the retrofits that need to be implemented, by 2015, which are primarily driven by compliance deadlines in the proposed Utility Air Toxics rule.

¹¹⁹ EPA promulgated the Final CSAPR on August 8, 2011 establishing a Federal Implementation Plan requiring 27 states to reduce power plant emissions of sulfur dioxide and nitrogen oxides that cross state lines and contribute to ozone and particulate pollution in other states. However, on October 14, 2011 EPA proposed technical revisions to the August 8th final rule, which are not yet finalized.

Figure 54: Incremental Capacity Reductions Due to the Combined EPA Regulation Scenario

This update concludes, however, that of these four rules, the 316(b) rule will have the greatest impact on the amount of capacity that may be economically vulnerable to retirement (approximately 25 to 39 GW) and, consequently, the greatest impact on Planning Reserve Margins, (Figure 55).

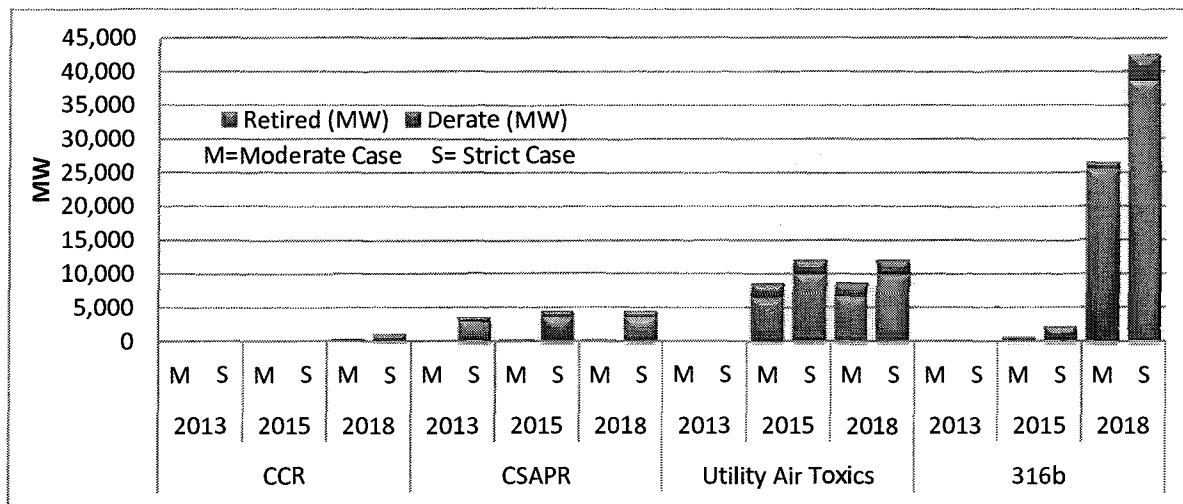
Figure 55: Incremental Capacity Reductions Due to Individual Rules

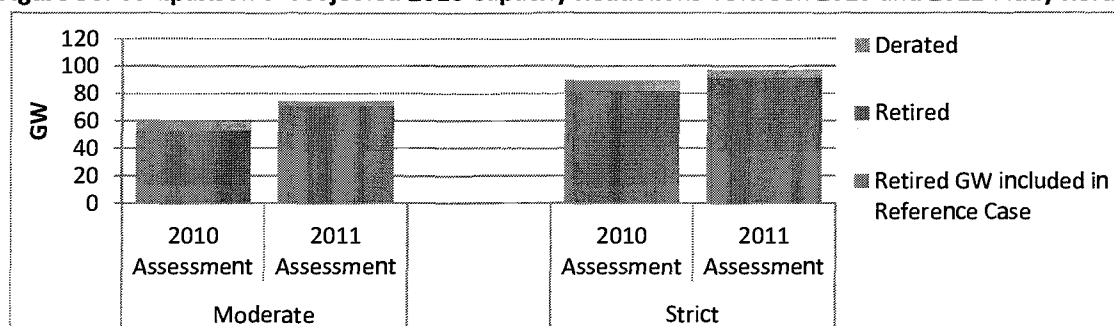
Figure 55, shows the respective rules' individual effects on retirements and derates. As the chart indicates, retirements or derates are not expected in 2013 under the Moderate Case. For the Strict Case, three of the four rules are not expected to cause any retirements or derates, and CSAPR is estimated to impact about 3.5 GW. In 2015, in the Moderate Case, CCR has no impact and the 316(b) rule impacts less than 1 GW due to their assumed compliance dates occurring beyond 2015. For 2015, the Utility Air Toxics rule alone would impact about 9 GW, in the Moderate Case, and could increase to about 12 GW, in the Strict Case.

When compared to the 2010 assessment, the results of this update show a net increase in the amount of potential decreases that can be expected by 2018 (Figure 56). While the potential impacts of

compliance with EPA regulations presented in this update are less than those in the 2010 NERC EPA Assessment, a total of approximately 38 GW of generation capacity (23 GW of coal and 15 GW of gas/oil units) have already committed and/or announced plans to retire. While these generating units most likely announced plans to retire for a variety of reasons, a majority of these units were identified in the 2010 NERC EPA Assessment as economically vulnerable.

These retirement announcements and commitments have decreased the amount of assessed capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. In the 2010 NERC EPA Assessment, the amount of retirement announcements was 13 GW; 25 GW less than in this update. These plant retirements have already been considered in the Regional assessments and the reductions included in the 2011 LTRA Reference Case.

Figure 56: Comparison of Projected 2018 Capacity Reductions between 2010 and 2011 Study Results



For this update, NERC studied the effects on Planning Reserve Margins from both unit retirement (assuming retired capacity is not replaced) and retrofits, which cause capacity reductions due to increased station loads to support emission controls or new intake structures. If no action is taken to replace existing resources, signs of not meeting resource adequacy requirements appear to be most prevalent in the ERCOT Region. In ERCOT, the Anticipated Planning Reserve Margin falls below the NERC Reference Margin in 2013 (Figure 57); 2015 when considering Adjusted Potential Resources.

MISO and NPCC-New England show decreased Planning Reserve Margins below the NERC Reference Margin Level by 2015—FRCC, PJM, SERC-E, SERC-N, and SERC-W by 2018. These areas may need more resources than are currently planned in this assessment.

For some Assessment Areas, Planning Reserve Margins are below the NERC Reference Margin Level in the Reference Case as well. In these Assessment Areas, concerns even without applying scenario assumptions may exist. For example, in the 2011 Reference Case, the ERCOT and NPCC-New England Anticipated Planning Reserve Margins fall below the NERC Reference Margin Level in 2014 and 2015, respectively.

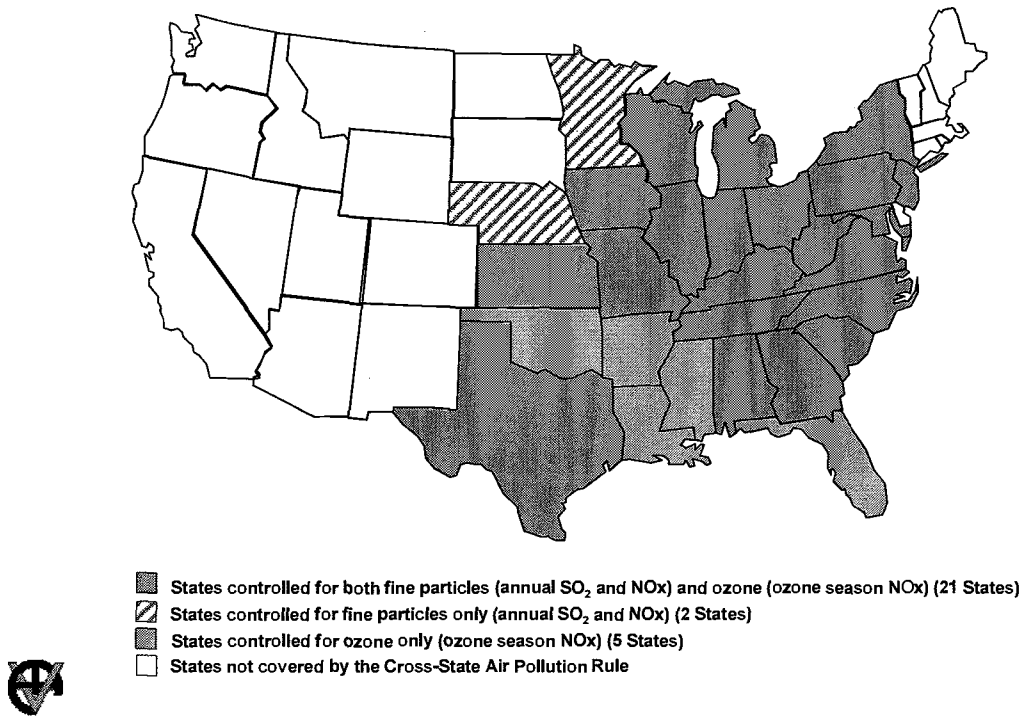
The impact on Planning Reserve Margins will be dependent on whether sufficient replacement capacity (or other system reinforcements) can be added in a timely manner to replace the generation capacity that is retired or lost. Unless additional resources are developed in certain Assessment Areas, beyond what is planned in the 2011 Reference Case, or additional time is provided to units needed to maintain

Current Status of EPA Regulations and Expected Outcomes

Cross-State Air Pollution Rule (CSAPR)

The EPA published its final CSAPR regulations on July 6, 2011, followed by the publication of proposed “technical corrections” in early October 2011. This rule was authorized under the 1990 Clean Air Act Amendments to address long-range transport of pollutants contributing to downwind non-attainment of fine particulate and ozone National Ambient Air Quality Standards. The EPA final rule creates three new pollutant cap and trade programs (SO_2 , annual NO_x and seasonal NO_x) that will affect fossil fuel sources across a twenty-eight state region (Figure 61). Nearly 91 percent (259,603 MW) of the existing coal-fired capacity (excluding announced retirement plans) are located within this affected region. The first phase of CSAPR program will take effect on January 1, 2012 and targets an additional reduction in some state SO_2 emission budgets in 2014.

Figure 61: CSAPR State Programs

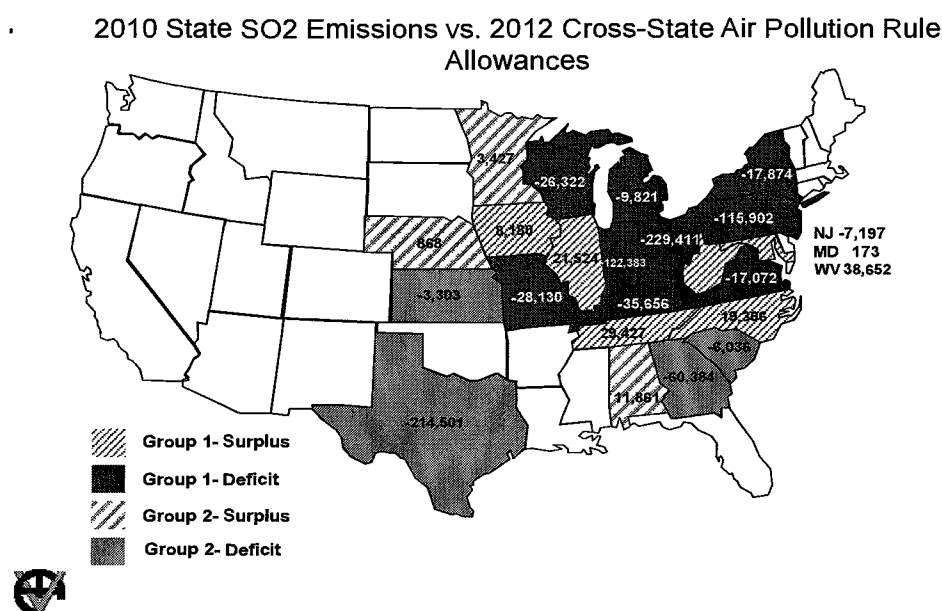


The additional emission reductions needed to comply are significant and highly concentrated to a few states (Figure 62). The constricted implementation period limits the available unit compliance options for meeting the 2012 emission caps. Companies are unable to permit and implement additional retrofit environmental control measures within 24-36 months, unless the construction phase has already commenced. Upgrades of existing flue gas desulphurization (FGD) equipment to enhance the performance of SO_2 removal and/or boiler upgrades enabling switching to lower sulfur fuels, will also take more than one year to engineer, permit, finance and implement. Insufficient time to retrofit units

with necessary environmental controls¹²⁸ combined the anticipated initial shortage of surplus allowances offered for sale will potentially leave companies with limited options to satisfy compliance requirements by 2012. The remaining short-term emission reduction measures include converting coal units to natural gas or other zero emission generation or in some cases, accelerating unit retirement.

However, as a market-based cap and trade program, CSAPR does not mandate any specific controls, or control installation dates, on generating units. For example, any new pollution control retrofit installations desired by unit operators do not have to be operational on January 1 of 2012 or January 1 of 2014. Controls installed after January 1 of any year simply reduce the number of allowances needed by a unit for compliance during the balance of that year (and future years) and surplus allowances created become available for compliance to other generation units. Ultimately, NERC's modeling projects CSAPR impacts will cause significant displacement of coal-fired megawatts, especially in 2012 and 2013.

Figure 62: CSAPR Concentrated Emission Reduction Burden



While coal generation will likely be displaced, CSAPR alone may not directly cause unit retirement. Companies will still have the option to comply by operating affected plants on a shorter time-frame, while also ensuring that generators are available to provide capacity to support reliability, especially during peak seasons and other periods when capacity is needed. Few studies have been published that identify the specific impacts of CSAPR to the electricity industry, yet most conclude very limited impacts on coal-fired on-peak capacity. EPA's CSAPR analyses project only 4.8 GW in coal unit retirements.¹²⁹ Although CSAPR alone will not likely force unit retirements, plant owners may still elect to retire older

¹²⁸ Including the need to switch to lower sulfur fuels.

¹²⁹ Rule Regulatory Impact Assessment (RIA) for Final Air Transport Rule (June 2011) EPA, pg 262

coal-fired units with higher operating costs as early as next year to comply with CSAPR as part of a combined environmental compliance strategy.

EPA's final CSAPR rule included some significant program differences from its earlier July 2010 draft proposal. These differences (versus its earlier proposal analyzed in the NERC 2010 EPA Assessment) include stricter emission caps, added and eliminated states from the program and increased the overall compliance costs. These changes have accelerated some unit retirement decisions and triggered the idling of additional units.

This update assumes that the program will be implemented as proposed and promulgated by EPA in July 2011 and does not consider EPA's more recent proposed rule that proposes to: 1) delay the Agency's "assurance provision" requirements from 2012 to 2014 to assist in the transition from CAIR to the CSAPR; and (2) to increase nine state emission budgets to address state, industry and ISO requests for increased state emission budgets and to address a limited number of errors in EPA model input assumptions as well as a few instances in which EPA modeling did not adequately address local system constraints or localized rules that may require "out of merit" economic dispatch of some generating units at certain times during the year.¹³⁰ The changes proposed by EPA in October will help mitigate the impact of the rule, particularly in 2012 and 2013.

Section 316(b) Cooling Water Intake Structures

Cooling water intake operation and structures are regulated under Section 316(b) of Clean Water Act (CWA). The 316(b) rule is implemented by the state water permitting agencies through the National Pollution Discharge Elimination System (NPDES) permit program of the CWA. EPA provides state permitting agencies with regulatory guidance and standards to determine Best Technology Available (BTA) to protect aquatic life from impingement (being trapped against the intake screen) and entrainment (passing through the screens and into the plant's cooling water system).

The prior version of the 316(b) rule that applied to existing generation facilities (known as the "Phase II Rule") was promulgated in 2004 and applied only to facilities with water usage greater than 50 million gallons per day (mgd), of which at least 25 percent was for cooling purposes.¹³¹ However, many aspects of the Phase II Rule were invalidated by the U.S. Court of Appeals in 2007 and the EPA withdrew the rule and directed the state permitting agencies to continue to implement the 316(b) rule on a site-specific basis using their best professional judgment.¹³² EPA published a proposed Phase II rule on April 20, 2011 that it is required to finalize under a Consent Agreement by July 2012.

¹³⁰ See October 14, 2011 "Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone" (76 FR 63,860).

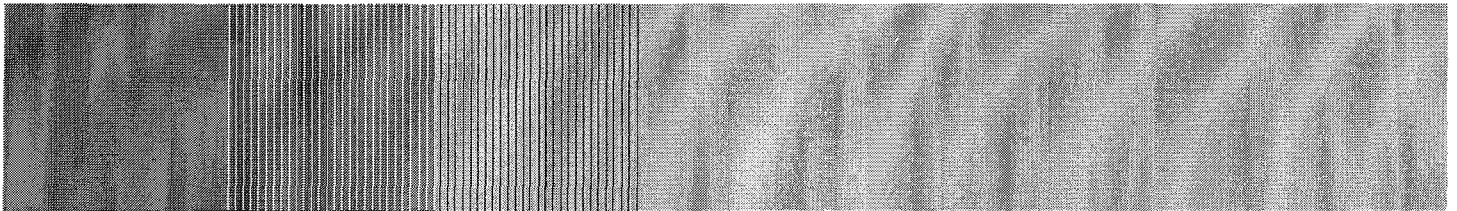
¹³¹ The EPA promulgated rules applicable to cooling water intake structures at manufacturing facilities in three phases: Phase I for new generation facilities, Phase II for existing large generation facilities, and Phase III for all remaining manufacturing facilities, including small electric generators. Phase I is in effect and requires that all new generation facilities install closed cycle cooling. Phase III has now been merged into the remanded Phase II rulemaking described herein.

¹³² The U.S. Supreme Court did review one aspect of the U.S. Court of Appeals opinion in the Phase II Rule. The Supreme Court determined that the EPA has the discretion under Section 316(b) to utilize a cost-benefit test on a site-specific basis to determine BTA for each affected facility.

19

September 2011

Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations



Prepared for:

American Coalition for Clean Coal Electricity

Prepared by:

NERA

Economic Consulting

Project Team

David Harrison, Jr., Ph.D.

Andrew Foss

James Johndrow

Eugene Meehan

Bernard Reddy, Ph.D.

Anne Smith, Ph.D.

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NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

I. Introduction

This report examines various effects of environmental regulations being developed by the U.S. Environmental Protection Agency (EPA) that affect the electric utility sector. We focus on the cumulative effects of four major environmental regulations on the energy sector and on economic activity, including employment and other measures.

A. Background

EPA has proposed major air emissions and other regulations in recent years. The two air regulations that are likely to have the greatest effect on the electric utility sector are the Cross-State Air Pollution Rule (CSAPR) and the regulations of mercury and other hazardous air emissions under Section 112 of the Clean Air Act (Utility MACT). These two regulations are at different stages of development. CSAPR was promulgated as a final rule in August 2011 (although there are some outstanding issues that EPA continues to review). Utility MACT was proposed in May 2011 and is expected to be made final in November 2011.

In addition to these two major air emissions rules, electric utility plants face other potential environmental regulatory requirements that would require additional investments. EPA recently has proposed a regulation under Section 316(b) of the Clean Water Act that regulates cooling water intake structures from electric power plants (and other facilities) in order to reduce losses to fish and other aquatic organisms. In addition, EPA has proposed regulations under the Resource Conservation and Recovery Act that would change how some plants manage their solid waste streams (the ashes from the burned coal and the sludge from their flue gas desulfurization (FGD) systems). Our assessments focus on the two air emission regulations and the 316(b) and CCR regulations; electricity generating units face environmental costs for other potential regulatory requirements—notably including those related to greenhouse gases—that are not included in our estimated impacts.

The EPA has developed assessments of the potential impacts of these various regulations and proposed regulations in separate regulatory impact analyses (RIAs). These RIAs provide important information on the potential social costs and social benefits of the proposed regulations as well as their potential effects on the energy sector. The public comments provide other information on the potential effects of the individual rules. Information on individual regulations, however, is limited because it does not measure the cumulative effects of many potential regulatory requirements either on individual power plants or on energy markets.

In the face of the limited information provided by evaluating individual regulations, various studies have evaluated the combined effects of various EPA regulations. Most of the studies have evaluated impacts on potential retirements of coal-fired units and some studies have estimated potential implications for electricity system reliability.⁵ These studies differ substantially in the

⁵ See Bipartisan Policy Center (2011), Brattle Group (2010), Charles River Associates (2010b), Edison Electric Institute (2011), ICF International (2010), M.J. Bradley & Associates and Analysis Group (2011), and North American Electric Reliability Corporation (2010). Note that the ability of these national studies to evaluate

environmental regulations they evaluate and in the nature of their evaluations. The prospect of substantial expenditures for pollution controls results in additional projected coal unit retirements, as every prior study has found.

The potential economic impacts of these rules—including their potential effects on employment and other measures of economic activity—have been less studied than their impacts on potential coal unit retirements, although some studies have considered potential economic impacts of some aspects of the regulations. For example, Ceres (2010) has developed estimates of the potential positive effects of the regulations on employment related to expenditures for emission controls. As various commentators have noted, however, this study did not provide information on the potential negative effects of higher electricity prices and other means of financing the added costs (see, e.g., Montgomery 2011). To our knowledge, no other study has estimated the cumulative economic impacts that include both the positive and negative effects of these four major regulations.

B. Objectives of This Report

The overall objective of this report is to provide estimates of the cumulative energy and economic effects of these four environmental regulations over the period from 2012 to 2020. That is, we consider the potential effects of these regulations on energy markets as well as on employment and other measures of economic activity. We have developed a modeling framework to estimate these various effects. We emphasize, however, that we have not developed estimates of the potential social benefits and social costs of these regulations and do not evaluate whether the individual regulations—or possible regulatory alternatives—would be desirable from a societal perspective.

In particular, the assessments presented in this study include the following three major types of effects.

1. *Coal unit retirements.* We consider the potential effects of regulatory requirements on coal unit retirement decisions based upon various key uncertainties, including the level of future natural gas and coal prices as well as the level of compliance costs. We use the results from this modeling framework to develop potential ranges of total U.S. coal unit retirements.
2. *Energy market effects.* We use information on predicted coal unit retirements as well as information on control costs for units that are not expected to retire to develop estimates of the potential effects of the policies on electricity and other energy markets. The results include estimates of the total compliance costs for the electricity sector due to the regulations, including control costs (capital as well as operation and maintenance), changes in fuel costs, and the costs of additional capacity added.
3. *Economic impacts.* The economic impacts of the regulations—including effects on employment, gross domestic product (GDP), and disposable personal income (i.e., personal

impacts on electricity system reliability is limited, since reliability impacts are likely to be sensitive to various system details (e.g., local transmission and voltage constraints) that are not included in the studies.

income after taxes)—are estimated by using the energy impacts in an economic impact model.

There are substantial uncertainties involved in developing these estimates. As discussed below, the model we use to develop estimates of coal unit retirements incorporates key uncertainties. It is important to emphasize, however, that other uncertainties are not modeled—including the possibility that coal and other units will face potential regulations related to greenhouse gases—and thus the projections presented in this report should be viewed as estimates of the likely impacts of only the four policies evaluated.

C. Outline of This Report

The remainder of this report is organized as follows. Chapter II provides an overview of the methodologies that are used and the policies that are evaluated in the study. Chapter III presents the results of the analyses. The appendices provide details on the models, compliance assumptions, methodologies, and results.

II. Overview of Methodologies and Policies

This chapter provides summary information on the methodologies used to estimate the potential economic impacts of the four policies. We also provide overviews of the four environmental policies that are modeled. Additional details of the models, policies, and data are provided in the appendices.

A. Modeling Framework

The methodology used in this study is based upon a set of linked models designed to assess the energy and economic impacts of environmental regulations affecting the electric utility sector. The empirical estimates of policy impacts are developed by comparing impacts under a baseline case (i.e., a case without the policies in place) and impacts under the policy case.

1. Overview of Modeling Framework

The modeling framework consists of three principal elements:

1. *Retirement Model*, which estimates whether coal units would be expected to retire based upon comparisons of the expected value of the future costs for the coal unit—including the likely potential costs of additional environmental controls—and the expected costs of an equivalent new natural gas combined cycle unit;
2. *National Energy Modeling System* (NEMS) model developed by the U.S. Energy Information Administration (EIA), which we use to assess the likely effects of compliance costs and coal unit retirements on the energy markets; and
3. *Policy Insight Plus model developed by Regional Economic Models, Inc. (REMI PI+)*, which we use to develop estimates of the economic impacts of energy market effects.

The following sections provide summaries of these elements.

2. Coal Unit Retirement Model

Power companies face the choice of retrofitting existing coal units to meet regulations or retiring them if the future costs do not justify continued operation in light of the likely costs of alternative sources to meet future electricity demand. We developed a detailed model to evaluate whether existing coal units in the United States would be expected to retire taking into account the potential costs of retrofit (and other future costs) as well as uncertainties in energy prices and other factors.

The retirement model is designed to mirror the decision by power companies on whether to retrofit coal-fired units with environmental controls or retire them and replace them with new capacity. A Monte Carlo formulation takes into account major uncertainties involved in this decision.

The model begins with estimates of the potential additional costs related to environmental policies. The potential future costs for coal units are based upon EIA data on unit characteristics (including capacity, capacity factor, heat rate, O&M costs, coal type, and current environmental controls) and on EPA information on the potential costs of the various controls. The potential technologies and costs for each coal-fired unit also reflect the flexibility that CSAPR provides—due to the potential for emissions trading—as well as the fuel and electricity prices based upon a similar level of retirements.⁶ The model thus takes account of the feedback effects of coal unit retirements on electricity and fuel prices.

The model uses statistical techniques and EPA data to simulate hourly electricity prices in each region—as a function of natural gas prices, time of day, season, peak/off-peak, and other factors—and generation decisions by coal units and potential replacement capacity, with generation a function of price and marginal cost. Uncertain parameters include the costs of controls, fuel prices and electricity prices, and the costs of the likely replacement alternative (a new natural gas combined cycle unit), with interactions among the uncertain parameters included in the Monte Carlo formulation.

Future coal unit costs are compared with the future costs of a new natural gas combined cycle unit by calculating the difference between the cost of the coal unit and the cost of the natural gas alternative in each of the 100 Monte Carlo draws. The unit is presumed to retire if the expected value of the cost difference is positive, i.e., on expectation, the coal unit would have greater future costs than a new natural gas combined cycle unit. Existing coal unit remaining lifetimes in these calculations are assumed to range between 10 and 20 years, depending upon unit age in 2015, to reflect the likelihood that owners of older units will have a shorter time horizon for recovering the cost of additional controls. The formulation accounts for the costs of using system energy during hours when coal units and the potential replacement capacity would not run.

3. NEMS Model

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of the U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

4. Regional Economic Models, Inc. Policy Insight Plus Model

The Regional Economic Models, Inc. (REMI) Policy Insight Plus (PI+) model produces estimates of the changes in employment, GDP, disposable personal income, and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs. Each version of the REMI PI+ model is custom-built for the regions of interest, which can range

⁶ We develop the implications of emissions trading flexibility provided by CSAPR by running the NEMS model with the relevant caps. The technologies identified in this run for each unit are used in the retirement model.

from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

B. Overview of Policies Modeled

This section summarizes the four policies evaluated in this report, including the two air emission regulations (CSAPR and Utility MACT) as well as Section 316(b) and CCR. Appendix A provides details on how the reference case and the four policies are modeled, including information on the control cost assumptions that are used.

1. Reference Case

The version of NEMS used for the model represents current legislation and environmental regulations as of January 31, 2011. The policies included in the reference case include state requirements for reduction of mercury emissions but not the Clean Air Mercury Rule, which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008. The reference case also includes the temporary reinstatement of the SO₂ and NO_x cap-and-trade programs included in the Clean Air Interstate Rule (CAIR) as a result of the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008.⁷ CAIR is included in the reference case through 2011. From 2012 onward, SO₂ and NO_x caps revert to pre-CAIR levels.

Proposed federal and state legislation, regulations, or standards—and sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in the reference case. The excluded policies include the four policies evaluated in our study.⁸

2. Cross-State Air Pollution Rule

EPA promulgated CSAPR in August 2011, following a draft rule (Clean Air Transport Rule, or CATR) proposed in August 2010 as a replacement to CAIR. CSAPR requires 27 states to reduce power plant emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from power plants in Eastern states in an effort to improve ozone and fine particulate air quality in other downwind states.⁹ Under CSAPR, EPA set new limits on SO₂ and NO_x emissions for each state beginning in 2012. The limits tighten in some states in 2014.

⁷ EPA finalized CAIR in 2005 but the rule was remanded to EPA by the D.C. Circuit Court of Appeals in 2008. The court decision required EPA to develop a different regulatory approach but to implement CAIR in the meantime.

⁸ Note that we include CSAPR in our assessments although EPA finalized CSAPR in August 2011 (EPA 2011a).

⁹ In a separate but related regulatory action, EPA also issued a supplemental notice of proposed rulemaking to require six states to make summertime NO_x reductions under the CSAPR ozone-season program. Finalizing this

3. Utility MACT

EPA proposed the Utility MACT rule in May 2011 to reduce emissions of mercury and other hazardous air pollutants (including other hazardous metals and acid gases) from coal- and oil-fired power plants across the country. The rule would set emission rate standards for different types of coal- and oil-fired units based on maximum achievable control technology. The emission rate standards would apply to mercury, other non-mercury metallic hazardous air pollutants (using particulate matter as a proxy), and acid gases (using hydrogen chloride as a proxy). Covered power plants would have up to three years to comply with the rule, but permitting authorities could grant one-year extensions to power plants if they required additional time.

4. Coal Combustion Residuals

EPA issued a proposed rule on June 21, 2010 related to the regulation of coal combustion residuals (also referred to as coal combustion waste) under the Resource Conservation and Recovery Act (RCRA). The regulations apply to the management of coal combustion residuals generated by steam electric power plants (i.e., electric utilities and independent power producers) that are disposed of in landfills and surface impoundments.

EPA co-proposed two approaches to the regulation of coal combustion waste. The first would regulate residuals under Subtitle C of RCRA as a “special waste.” The second would regulate residuals under Subtitle D as a non-hazardous waste. Our assessments are based on the potential costs to individual units of regulating coal combustion residuals under Subtitle D.

5. Clean Water Act Section 316(b)

On April 20, 2011, EPA proposed cooling water intake requirements for existing power plants and other industrial facilities under Section 316(b) of the Clean Water Act. These facilities withdraw water and in the process, fish and other aquatic organisms are lost if they become trapped against intake screens (“impingement”) or pulled into the cooling system (“entrainment”). Various technologies reduce impingement and entrainment losses, including the retrofit of plants with cooling towers to provide closed-cycle cooling.

EPA evaluated four alternatives for setting Section 316(b) standards, with Option 1 identified as its preferred option. Option 1 would require that existing plants withdrawing water above a proposed 2 million gallon per day threshold reduce the impingement mortality by meeting various national standards (EPA 2011b, pp. 22203-22204). In contrast, entrainment controls would be set on the basis of site-specific requirements. Under EPA’s proposal, permit writers will be required to consider converting the condenser cooling system from once-through cooling to closed-cycle cooling through the use of cooling towers, which reduces net flow and thus entrainment losses (albeit at substantial cost and often undesirable environmental side-effects). EPA estimated the cost of installing cooling towers under Option 1 at the 46 fossil units with the

supplemental program would bring the total number of covered states under the CSAPR to 28. EPA reports that it is proposing to finalize this proposal by late fall 2011.

largest cooling water withdrawals from tidal waters. Our assessments are based on the potential costs to individual units of the Option 1 alternative.

III. Study Results

This chapter summarizes the study results for our analyses of the cumulative energy and economic impacts of the four environmental policies. The results are grouped into three categories: (1) coal unit retirements; (2) energy market effects; and (3) economic impacts. Additional details are provided in the appendices.

A. Coal Unit Retirements

1. National Results

The potential costs of the four policies are estimated to lead to 39 gigawatts (GW) of prematurely retired capacity among the current coal-fired power plants. This figure represents additional retirements above those in the reference case (i.e., retirements predicted without the four regulations in place) and accounts for about 12 percent of the 2010 U.S. coal-fired electricity generating capacity. As noted, this estimate does not include the potential effects of other potential requirements—notably potential greenhouse gas emission regulations—or concerns related to detailed electricity system reliability.

We developed an assessment of the potential range of possible retirements using the information from the 100 individual draws from the retirement model. We calculated the retirements in each of the draws as a sensitivity analysis, assuming that a unit would retire if its future costs were greater than the future costs of the natural gas unit in those circumstances. The range of retirements was from 17 GW to 79 GW in these 100 cases. This range is roughly consistent with sensitivity results from other studies, although the other studies do not use the same assumptions and methodology.¹⁰

2. Uncertainties Regarding Estimated Retirements

The range of potential retirements provides an indication of the substantial uncertainty surrounding potential retirements due to uncertainties in future natural gas prices, control costs and other factors influencing individual retirement decisions. There are, however, some factors that are not included in the retirement model. The retirement model does not account for the possibility that adjustments could occur if the local effects of retirements were severe (e.g., likely to impair electricity system reliability). These adjustments would tend to reduce the actual level of retirements below those predicted by our model, which is based upon economic calculations, although the potential impacts on electricity prices could be greater than estimated assuming units are allowed to retire.

In addition, the model does not factor into the calculation of expected future costs the potential costs and other impacts associated with greenhouse gas regulations. Even without the prospect of

¹⁰ EIA, for example, reports a range of retirements for the two air emissions regulations from 4.7 GW to 63.8 GW (net of reference case retirements) depending upon the level of future natural gas prices as well as the likely time horizon for amortizing compliance capital costs (EIA 2011, p. 50).

20



FEDERAL REGISTER

Vol. 77

Thursday,

No. 32

February 16, 2012

Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044, FRL-9611-4]

RIN 2060-AP52; RIN 2060-AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On May 3, 2011, under authority of Clean Air Act (CAA) sections 111 and 112, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units (76 FR 24976). After consideration of public comments, the EPA is finalizing these rules in this action.

Pursuant to CAA section 111, the EPA is revising standards of performance in response to a voluntary remand of a final rule. Specifically, we are amending new source performance standards (NSPS) after analysis of the public comments we received. We are also finalizing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

Pursuant to CAA section 112, the EPA is establishing NESHAP that will require coal- and oil-fired EGUs to meet hazardous air pollutant (HAP) standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the HAP listed in CAA section 112(b)(1).

DATES: This final rule is effective on April 16, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The EPA established two dockets for this action: Docket ID. No.

EPA-HQ-OAR-2011-0044 (NSPS action) or Docket ID No. EPA-HQ-OAR-2009-0234 (NESHAP action). All documents in the dockets are listed on the <http://www.regulations.gov> Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through <http://www.regulations.gov> or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1741.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541-5430; Fax number (919) 541-5450; Email address: maxwell.bill@epa.gov. For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541-4003; Fax number (919) 541-5450; Email address: fellner.christian@epa.gov.

SUPPLEMENTARY INFORMATION:

The information presented in this preamble is organized as follows:

- I. General Information
 - A. Does this action apply to me?
 - B. Where can I get a copy of this document?
 - C. Judicial Review
 - D. What are the costs and benefits of these final rules?
- II. Background Information on the NESHAP
 - A. What is the statutory authority for this final NESHAP?
 - B. What is the litigation history of this final rule?
 - C. What is the relationship between this final rule and other combustion rules?
 - D. What are the health effects of pollutants emitted from coal- and oil-fired EGUs?
- III. Appropriate and Necessary Finding
 - A. Overview

- B. Peer Review of the Hg Risk TSD Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired EGUs and EPA Response
- C. Summary of Results of Revised Hg Risk TSD of Risks to Populations With High Levels of Self-Caught Fish Consumption
- D. Peer Review of the Approach for Estimating Cancer Risks Associated With Cr and Ni Emissions in the U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Mercury Hg HAP and EPA Response
- E. Summary of Results of Revised U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Mercury Hg HAP
- F. Public Comments and Responses to the Appropriate and Necessary Finding
- G. EPA Affirms the Finding That It Is Appropriate and Necessary To Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Mercury Hg HAP From EGUs
- IV. Denial of Delisting Petition
 - A. Requirements of Section 112(c)(9)
 - B. Rationale for Denying UARG's Delisting Petition
 - C. EPA's Technical Analyses for the Appropriate and Necessary Finding Provide Further Support for the Conclusion That Coal-Fired EGUs Should Remain a Listed Source Category
- V. Summary of the Final NESHAP
 - A. What is the source category regulated by this final rule?
 - B. What is the affected source?
 - C. What are the pollutants regulated by this final rule?
 - D. What emission limits and work practice standards must I meet?
 - E. What are the requirements during periods of startup, shutdown, and malfunction?
 - F. What are the testing and initial compliance requirements?
 - G. What are the continuous compliance requirements?
 - H. What are the notification, recordkeeping and reporting requirements?
 - I. Submission of Emissions Test Results to the EPA
- VI. Summary of Significant Changes Since Proposal
 - A. Applicability
 - B. Subcategories
 - C. Emission Limits
 - D. Work Practice Standards for Organic HAP Emissions
 - E. Requirements During Startup, Shutdown, and Malfunction
 - F. Testing and Initial Compliance
 - G. Continuous Compliance
 - H. Emissions Averaging
 - I. Notification, Recordkeeping and Reporting
 - J. Technical/Editorial Corrections
- VII. Public Comments and Responses to the Proposed NESHAP
 - A. MACT Floor Analysis
 - B. Rationale for Subcategories
 - C. Surrogacy
 - D. Area Sources
 - E. Health-Based Emission Limits
 - F. Compliance Date and Reliability Issues

- G. Cost and Technology Basis Issues
- H. Testing and Monitoring
- VIII. Background Information on the NSPS
 - A. What is the statutory authority for this final NSPS?
 - B. What is the regulatory authority for the final rule?
- IX. Summary of the Final NSPS
- X. Summary of Significant Changes Since Proposal
- XI. Public Comments and Responses to the Proposed NSPS
- XII. Impacts of the Final Rule
 - A. What are the air impacts?
 - B. What are the energy impacts?
 - C. What are the cost impacts?
 - D. What are the economic impacts?
 - E. What are the benefits of this final rule?
- XIII. Statutory and Executive Order Reviews

- A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review
- B. Paperwork Reduction Act
- C. Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act (RFA) of 1996 (SBREFA), 5 U.S.C. 601 et seq.
- D. Unfunded Mandates Reform Act of 1995
- E. Executive Order 13132, Federalism
- F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments
- G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks
- H. Executive Order 13211, Actions Concerning Regulations That

- Significantly Affect Energy Supply, Distribution, or Use
- I. National Technology Transfer and Advancement Act
- J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
- K. Congressional Review Act

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

Category	NAICS code ¹	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	² 221122	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/local/tribal government	² 221122	Fossil fuel-fired electric utility steam generating units owned by states, tribes, or municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

¹ North American Industry Classification System.

² Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. To determine whether you, as owner or operator of a facility, company, business, organization, etc., will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9981. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the dockets, an electronic copy of this action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature by the Administrator, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: <http://www.epa.gov/ttn/oarpg/>. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 16, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]" Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of

General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

D. What are the costs and benefits of this final rule?

Consistent with Executive Order (EO) 13563, "Improving Regulation and Regulatory Review," we have estimated the costs and benefits of the final rule. This rule will reduce emissions of HAP, including mercury (Hg), from the electric power industry. Installing the technology necessary to reduce emissions directly regulated by this rule will also reduce the emissions of directly emitted PM_{2.5} and sulfur dioxide (SO₂), a PM_{2.5} precursor. The benefits associated with these PM and SO₂ reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA estimates that this final rule will yield annual monetized benefits (in 2007\$) of between \$37 to \$90 billion using a 3 percent discount rate and \$33 to \$81 billion using a 7 percent discount rate. The great majority of the estimates are attributable to co-benefits from reductions in PM_{2.5}-related mortality. The annual social costs, approximated

by the sum of the compliance costs and monitoring and reporting costs, are \$9.6 billion (2007\$) and the annual quantified net benefits (the difference between benefits and costs) are \$27 to \$80 billion using a 3 percent discount rate or \$24 to \$71 billion using a 7 percent discount rate. It is important to note that the PM_{2.5} co-benefits reported here contain uncertainty, due in part to the important assumption that all fine particles are equally potent in causing premature mortality and because many

of the benefits are associated with reducing PM_{2.5} levels at the low end of the concentration distributions examined in the epidemiology studies from which the PM_{2.5}-mortality relationships used in this analysis are derived.

The benefits of this rule outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. The co-benefits are substantially attributable to the 4,200 to 11,000 fewer PM_{2.5}-related premature

mortalities estimated to occur as a result of this rule. The EPA could not monetize some costs and important benefits, such as some Hg benefits and those for the HAP reduced by this final rule other than Hg. Upon considering these limitations and uncertainties, it remains clear that the benefits of this rule, referred to in short as the Mercury and Air Toxics Standards (MATS), are substantial and far outweigh the costs.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL RULE IN 2016
[Billions of 2007\$]^a

	3% Discount rate	7% Discount rate
Total Monetized Benefits ^b	\$37 to \$90	\$33 to \$81.
Partial Hg-related Benefits ^c	\$0.004 to \$0.006	\$0.0005 to \$0.001.
PM _{2.5} -related Co-benefits ^b	\$36 to \$89	\$33 to \$80.
Climate-related Co-Benefits ^d	\$0.36	\$0.36.
Total Social Costs ^e	\$9.6	\$9.6.
Net Benefits	\$27 to \$80	\$24 to \$71.
Non-monetized Benefits	Visibility in Class I areas. Other neurological effects of Hg exposure. Other health effects of Hg exposure. Health effects of ozone and direct exposure to SO ₂ and NO ₂ . Ecosystem effects. Health effects from commercial and non-freshwater fish consumption. Health risks from exposure to non-mercury HAP.	

^a All estimates are for 2016, and are rounded to two significant figures.

^b The total monetized benefits reflect the human health benefits associated with reducing exposure to PM_{2.5}. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted PM_{2.5} and SO₂ reductions. The estimate of social benefits also includes CO₂-related benefits calculated using the social cost of carbon, discussed further in chapter 5 of the RIA. Mercury benefits were calculated using the baseline from proposal. The difference in emissions reductions between proposal and final does not substantially affect the Hg benefits.

^c Based on an analysis of health effects due to recreational freshwater fish consumption.

^d This table shows monetized CO₂ co-benefits that were calculated using the global average social cost of carbon estimate at a 3 percent discount rate. In section 5.6 of the Regulatory Impact Analysis (RIA) we also report the monetized CO₂ co-benefits using discount rates of 5 percent, 2.5 percent, and 3 percent (95th percentile).

^e Total social costs are approximated by the compliance costs for both coal- and oil-fired units. This includes monitoring, recordkeeping, and reporting costs.

For more information on how EPA is addressing EO 13563, see the EO discussion in the Statutory and Executive Order Reviews section of this preamble.

II. Background Information on the NESHAP

On May 3, 2011, the EPA proposed this rule to address emissions of toxic air pollutants from coal and oil-fired electric generating units as required by the CAA. The proposal explained at length the statutory history and requirements leading to this rule, the factual and legal basis for the rule and its specific provisions, and the costs and benefits to the public health and environment from the proposed requirements.

The EPA received over 900,000 comments from members of the public on the proposed rule, substantially more than for any other prior regulatory

proposal. The comments express concerns about the presence of Hg in the environment and the effect it has on human health, concerns about the costs of the rule, how challenging it may be for some sources to comply and questions about the impact it may have on this country's electricity supply and economy. Many comments provided additional information and data that have enriched the factual record and enabled EPA to finalize a rule that fulfills the mandate of the CAA while providing flexibility and compliance options to affected sources—options that make the rule less costly and compliance more readily manageable.

This rule establishes uniform emissions-control standards that sources can meet with proven and available technologies and operational processes in a timeframe that is achievable. They will put this industry, now the single largest source of Hg emissions in the

United States (U.S.) with emissions of 29 tons per year, on a path to reducing those emissions by approximately 90 percent. Emissions of other toxic metals, such as arsenic (As) and nickel (Ni), dioxins and furans, acid gases (including hydrochloric acid (HCl) and SO₂) will also decrease dramatically with the installation of pollution controls. And the flexibilities established in this rule along with other available tools provide a clear pathway to compliance without jeopardizing the country's energy supply.

This preamble explains EPA's appropriate and necessary finding, the elements of the final rule, key changes the EPA is making in response to comments submitted on the proposed rule, and our responses to many of the comments we received. A full response to comments is provided in the response to comments document available in the docket for this rulemaking.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (e.g., by the URS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Another commenter noted that utilities that failed to plan ahead "should not be permitted to use their own inaction to justify more time." Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL-CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register**. Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for

existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.³²¹ The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the

³²¹ The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

21

Seeking Alpha ^α

American Electric Power's CEO Discusses Q1 2012 Results - Earnings Call Transcript

Executives

Charles E. Zebula - Senior Vice President and Treasurer

Nicholas K. Akins - Chief Executive Officer, President and Director

Brian X. Tierney - Chief Financial Officer and Executive Vice President

Robert P. Powers - Chief Operating Officer and Executive Vice President

David M. Feinberg - Senior Vice President, General Counsel, Secretary, General Counsel of American Electric Power Service Corp, Senior Vice President of American Electric Power Service Corp

Analysts

Greg Gordon - ISI Group Inc., Research Division

Dan Eggers - Crédit Suisse AG, Research Division

Paul T. Ridzon - KeyBanc Capital Markets Inc., Research Division

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Jim von Riesenmann

Anthony C. Crowdell - Jefferies & Company, Inc., Research Division

Stephen Byrd - Morgan Stanley, Research Division

Michael J. Lapidés - Goldman Sachs Group Inc., Research Division

Steven I. Fleishman - BofA Merrill Lynch, Research Division

Ali Agha - SunTrust Robinson Humphrey, Inc., Research Division

Andrew Bischof - Morningstar Inc., Research Division

American Electric Power ([AEP](#)) Q1 2012 Earnings Call April 20, 2012 9:00 AM ET

Operator

Ladies and gentlemen, thank you for standing by, and welcome to the First Quarter 2012 Earnings Conference Call. [Operator Instructions] As a reminder, this conference is being recorded. I would now like to turn the conference over to Chuck Zebula. Please go ahead.

Charles E. Zebula

Brian X. Tierney

Quarter-to-date, Paul, we are. But so much of that depends on what happens with this ESP case, and particularly, the capacity case. And if we get a negative outcome on the capacity case, and we go to something that looks like RPM, that could significantly accelerate shopping. And so the run rate for the year, given the uncertainty that we face after June 1, is something that's certainly in question. And we wouldn't anticipate that you could just extrapolate the year-to-date numbers and come up with a reasonable outcome with what the capacity case gets resolved at.

Paul T. Ridzon - KeyBanc Capital Markets Inc., Research Division

And then lastly, when you say you're 80% hedged on your coal buy for '13, that assumes the same kind of fuel mix as you're kind of laid out in the first quarter?

Nicholas K. Akins

Yes, that's the same kind of fuel mix, I think, and 80% hedged. That -- it's give or take because you're obviously looking during the year at what the actual coal requirements are going to be. So we continually -- and we're becoming more flexible in terms of our coal contracting to ensure that we do have the flexibility if natural gas prices continue to be low, which we expect they will, that we'd be able to respond from a contractual standpoint.

Paul T. Ridzon - KeyBanc Capital Markets Inc., Research Division

Is building your coal piles more a function of weather or fuel mix?

Nicholas K. Akins

I think it's both. Weather and -- it's weather and natural gas prices. Because one of -- I guess, one of the beauties of our system, we bought 5,000 megawatts of gas in the last few years, or built 5,000 megawatts and it gives a lot of flexibility in terms of if you have low gas prices, they're competing on a marginal basis with coal-fired generation then we can make those adjustments. What we're having to change, obviously, is sort of this black swan event of natural gas prices and making us think about what the future coal contracting provisions will be so that we ensure that they're flexible because there was always an assumption that coal is going to be lower than natural gas. Well, that's not the case, so we need to be flexible on both sides.

Operator

And now, we'll go to the line of Jonathan Arnold from Deutsche Bank.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Can I ask first on the sales numbers in Q1? Obviously, the weather was particularly abnormal and then there's negative nearly 3% number you have normalized in residential. Is that -- how confident are you that that's kind of a good reflection of the real underlying usage or the weather models is sort of thrown off by a very unusual winter?

Brian X. Tierney

Jonathan, it's hard to tell at this point. If you look at that chart on Slide 5, you'll see there's some -- been some pretty extreme volatility in that residential number Q-over-Q. Second quarter of last year was up 4.4%, and then it went to moderately negative in the third quarter. So I think until we see a trend that we can hang our hat on, we really need to watch that data. We don't see anything that is a give up the ghost on the residential customer account or usage for us. But obviously, we're watching that. We'll continue to watch that quarter-to-quarter. We don't like seeing it down 2.8% versus last year. But as you stated, it is an extreme weather year, and making sure that our weather normalization calculations are right when you have such extremes as we're having right now. And to be frank with you, as we have last year, you really need to watch the trend over time.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

So you're kind of leaving the full year forecast where it is until you get a little better sense of the rest of the year?

22

Generation

Technology is Reinventing the Utility Industry at Duke Energy: Jim Rogers



By Felicity Carus



The US utility industry will look fundamentally different within the next forty years as a paradigm shift transforms the sector, the chief of one of the country's largest energy providers said.

"We're going to reinvent our business, we're going to adopt new technologies," said Jim Rogers, Duke Energy CEO. "When you look at our company four decades from now it will look fundamentally different.

"We have a blank sheet of paper to design what future energy generation fleet will become in the future ... [and] we're going to have to rethink the grid in a different way."

He said that the company had looked at 700 technologies over last 4 years and selected 27 pilot projects in its own system and has partnerships with 63 pilots the company in the US.

Speaking at the Hamilton Project Forum on energy at Stanford University, he said: "I believe our business will go from being a kilowatt hour seller of electricity but to more of an optimiser of the grid.

"The model I see is one of optimisation [in] deploying capital in homes and businesses and deploying distributed generation [such as solar] in the areas we serve."

Cybersecurity A Threat to Centralization

Rogers also said that centralized models of energy generation and distribution would have to change to avoid threat of cyber-attack and that the smart grid was "a concept that's been oversold and overhyped and turned out to be an impediment to development of new technology."

The Federal Energy Regulatory Commission last week conditionally approved Duke Energy's merger with Progress Energy in a \$26 billion all-stock deal. The merger would create the largest utility company in the US with a generating capacity of 57 GW and seven million customers in North and South Carolina, Florida, Indiana, Ohio and Kentucky.

As of 2010, Duke's generation fleet was 48% coal-fired, with some of the plants dating back to the early part of the 20th century. Under new Environmental Protection Agency (EPA) regulations, Duke Energy plans to retire 2,773MW of older coal-fired generation by 2015 in addition to the retirement of 1,027MW of capacity in 2011 and early 2012.

Duke Energy now dispatches its coal fleet after all its other sources of generation, said Rogers.

"Today we're dispatching hydro first, then our nuclear, then natural gas before our even our most efficient coal plants. Gas prices have to go above \$4.25

per mmbtu before we start dispatching our most efficient coal."

Getting Ahead of Cleantech

As the grid transitions away from coal, Rogers said his company would not stand in the way of progressive action to supply the US electric grid with cleaner sources of energy.

"We're not going to be one of these incumbents that fights it, we're going to get ahead of it. When a parade forms on an issue you can throw your body in front of it and let them walk over you or you can jump in front of the parade and pretend it's yours."

But he said that the strength of the US electric grid was the diversity in its energy portfolio and while it was tempting to build combined-cycle gas fired power stations because of low natural gas prices, to build gas-only would be a mistake.

To pick up on Ben Franklin, who said there were two things that are certain in life: death and taxes. I would add the volatility of natural gas prices." - Rogers

"The strength today of the electric system in America that we have a portfolio of ways to generate electricity. My number one fear is that we will be forced to build gas and push out solar [which] will trump wind because of its distributed nature.

"We have to resist the temptation as we retire and replace existing generation to build nothing but natural gas. That would be a mistake."

Global Gas

A policy paper published this month by the Hamilton Project on the strategy for US natural gas pointed to increasing pressure to export natural gas into the global market. Spot prices in 2012 fell below \$2 per 1,000 cubic feet, whereas gas traded at \$11 in Europe and over \$15 in Asia.

Exports and diversification of demand could drive US domestic prices upwards, said Kenneth A Hersh, CEO of NGP Energy Capital Management.

"Price relationships such as oil versus gas can change and they wildly change. In the late 1970s we were implementing law that said we should not use natural gas for power generation in this country because it's too vital.

"If 10% cars ran on natural gas we'd use 20% of the US natural gas supply. Don't think that the price of natural gas would stay low. Understanding the full cycle of movements you can't rely on the [price] relationship. It's a commodity."

Rogers also said that focus on a single fuel as had happened in transportation would be problematic in the future. Policy decisions based on fossil fuel prices and forecast supply by previous administrations decades ago had left today's energy industry with huge legacy burdens, which would make a carbon tax unfair.

"There is an inherent unfairness to a carbon tax. There are 25 states in this country where more than 50% of the electricity comes from coal. Why is there so much coal in the states? In 1978, 18% of electricity in this country was coming from oil and we were told by the government go build coal and nuclear because that's the future."

A cap and trade system would be a fairer, he said, adding that utilities needed to anticipate future policies, such as a price on carbon.

"I know there will be some price on carbon in the next four years. I factor in a carbon price into every decision on what I build. That's the only prudent way for me to make these longer-term investments."

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23



U.S. Coal Review

Energy Publishing's Weekly Digest of U.S. Coal Market Prices and Activity

ISSUE #1933

November 12, 2012

TODAY'S TOP 10 Ratcliffe project in Kemper County, MS making nice progress toward May 2014 target

Pg. 2 *Production cut talk continues to dominate coal landscape as Q3 results roll out*

Pg. 4 *Costs are going up as prices stay flat as some CAPP producers pushed to the brink*

Pg. 7 *As U.S. coal markets stay quiet things perk up a bit on the international side of things*

Pg. 15 *Oxford continues to work through tough market conditions, focuses on NAPP*

Pg. 17 *Vectren has seen coal earnings decline but has confidence in Illinois Basin mines*

Pg. 20 *'Worst behind us' being seen and hard a lot in the metallurgical coal markets*

Pg. 22 *Duke sees Edwardsport, Cliffside plants as mainstays in regional power pictures*

Pg. 25 *Peter Socha takes to diamond to pitch message steam coal could wear rally cap*

Pg. 28 *West Coast port problems to persist in U.S. as Canadian ports expand using U.S. coal company dollars*

Pg. 29 *EPA on high alert for a possible GOP victory, plans rapid regulatory response?*

By Paul McAfee
pmcafee@energypublishing.biz

Southern Company's Plant Ratcliffe IGCC project in Kemper County, MS, is progressing nicely.

The project, which would gasify lignite located near the plant, is 70 percent complete and is targeted for commercial operation in May 2014, Southern Company CEO Tom Fanning said during the company's third quarter 2012 earnings call. Cost projections remain on target to finish at or below \$2.88 billion.

Construction tasks listed as complete include gasifier bottom lifts and CO2 absorbers installed. Construction target dates for completion include: gasifier center lifts – Quarter 4 2012; gasifier top lifts – Quarter 1 2013 and air compressor installed – Quarter 2 2013.

"We continue to actively manage ongoing pressures on costs and schedule, which are typical for a project of this scale. Installation of the gasifiers and assembly is proceeding exceptionally well, and the carbon dioxide absorbers are all in place.

"Natural gas and effluent water pipelines, as well as critical transmission upgrades have all been completed on time or ahead of schedule.

Contracts for the sale of final byproducts of the gasification process had been finalized, which combined with the expected savings from financing and factoring in current capital estimates, are projected to provide approximately \$500 million more in

value to Mississippi Power customers than was originally projected.

"Over the next few months and early into 2013, the remaining gasifier lift will be completed. Other major elements, such as the water plant and air compressor are scheduled to be completed in the spring. Start-up activity begins next year as well, with the first fire of the gas turbines scheduled for the second quarter of 2013.

"Heat-up of the gasifiers is scheduled for late 2013, and reliable flows of gas are expected to begin in early 2014. Once the plant is finished and operational, customers in Mississippi will enjoy the benefits of a clean, cost-effective cutting edge energy for decades to come."

A questioner on the call wanted to know how Southern Company management can be confident of the new facility's key target dates, asking "how can you be comfortable with the performance of the gasifier before it's actually being installed?"

"I remember (being asked) a question about why we were different than Edwardsport, and I went off on a soliloquy for 20 minutes," Fanning said. "I'll resist the temptation to do that, but let me give you some headlines as to why we're different. Number 1, this is our technology. We're not buying from a third party.

"Number 2, you know that we are the only one in the industry with an engineering and construction services group of 1,600 people. We're able to self-build this effort, along with sev-

Continued on page 2

Production...

Continued from page 2

nualized production rate by an additional 16 million tons. These actions are being taken in a pricing environment where we estimate that the majority of U.S. thermal coal would be uneconomic to produce at today's spot market prices."

To ensure that Alpha's operations and cost base are appropriately aligned with the current market environment, approximately 50 percent of the planned reduction in tonnage will come from the Powder River Basin, where the company plans to adjust production to match currently committed and priced volumes for 2013.

Another 40 percent of the reduction will come from the higher-cost Eastern thermal coal production base in Central Appalachia.

These restructuring actions began in September and will be phased in through early 2013.

Alpha reiterated that it has avoided forcing unwanted coal into the marketplace and will continue with that disciplined strategy in the coming months.

"If you look at the near term, 2012 shipments (of PRB coal) picked up," said Alpha President Paul Vining. "I guess other suppliers were just shipping on contracts. Buyers have been active with RFPs for good reason. They are looking at the forward strip on gas and it's starting to move. They are trying to lock things in for 2-3 years at fairly depressed prices and gain some benefit out of forward curves while gas is low. That's created a lot of contracting activity."

Added Crutchfield: "I think if you look at the difference in the second and third quarter, it was vastly different. What we saw was an immediate volume response when gas prices started moving up, but there still is an

overhang to work through.

"I think as customers work through that overhang you will see a price response at some point. We are just taking the view that, while we can move the tons and had opportunities to move the tons that match our production profile out there, we are just choosing not to do it because we don't think it makes good financial sense. We will just hold back now and wait for the right price."

When gazing into next year's markets and how natural gas will potentially impact coal's share of generation, Crutchfield appears to be optimistic.

"I guess it (natural gas pricing) has effectively doubled over the past several months," he said. "We have always anticipated this match between natural gas and coal. We just figured it might take longer to play out. We did not expect to have to deal with it over the course of a couple of quarters.

"I think long-term, as you think about the globe and the dislocated markets that are in place globally, it's just a matter of time before they begin to harmonize. Europe is in the \$12 range, Japan is in the \$16-17 range, and we are covered up with \$3.60 gas in the U.S. I think it's just a matter of time before you begin to see those markets harmonize on a global basis.

"It will take time and a lot of capital expenditure from an LNG perspective, and that's where I think you begin to see coal start to get back some market share and take back a little bit more meaningful role than it has had the last several months.

"It continues to be an evolving marketplace. It's not a lot of fun working through it, but I think we have a good plan, and we will continue to be focused on the right things." □

Coal's heartaches by the numbers could change as Southern has fuel flexibility

Natural gas-fired generation from Southern Company's fleet of power plants is currently plenty high versus the recent past, but it's still a ways off from the potential numbers that could be reached in the next few years.

As to the direction the giant power producer takes next year and beyond, much, of course, depends on the pricing of coal and natural gas. But during a recent 2012 third quarter earnings call, Southern Company officials said they have the capability to push the percentage of natural gas further in the overall fuel mix of the fleet.

Southern Company's third quarter 2012 generation mix included: coal – 41 percent; gas/oil – 43 percent and nuclear – 15 percent. For the 2011 third quarter, the numbers were: coal – 51 percent; gas/oil – 34 percent and nuclear 14 percent.

Year-to-date 2012, coal is at 37 percent; gas/oil – 45 percent and nuclear – 16 percent. For year-to-date 2011, the numbers were: coal – 52 percent; gas/oil – 31 percent and nuclear 15 percent.

"We have a great deal of optionality in our fuel mix," said CEO Tom Fanning. "If gas prices are cheap and coal prices are expensive, we in the future – and I think these are 2015 numbers – could take our gas-fired energy generation up to 55 percent and back coal to 25 percent.

"That's my guess. If the reverse happens and gas gets expensive and coal is cheap, I think we can take coal to 45 percent and back gas to 35. There is a broad range of optionality."

Fanning offered a breakdown of the break-even dis-

Continued on page 4

Coal's heartaches...

Continued from page 3

patch curves going forward.

"Gas at \$1.25 per million Btu...it has to fall below that before it dispatches ahead of nuclear, and frankly (the same is true) at Kemper County (integrated gasification combined cycle facility expected to begin commercial operation in early 2014). Kemper County will be in the same neighborhood.

"When we think about PRB, you have gas in the range of \$3-4, call it \$3.50 for gas to dispatch ahead of PRB. That would be Scherer and Miller.

With Central Appalachian coal, "we have been moving away from Central App to Illinois Basin," Fanning continued. "Some of that depends on how we unfold in the years ahead, but those numbers have come down a bit with the move more to Illinois coal.

"We used to say Central App coal was kind of \$6.00-6.50. Now with Illinois being a more important part of the future as we conform with MATS, that number looks more like \$5.00-6.00, somewhere in there."

Asked if it appears that Southern Company will continue to run its natural gas-fired plants really hard in 2013, Fanning had a very simple, succinct response: "Yes." □

Costs are going up as prices stay flat as some CAPP producers pushed to the brink

It's not happy times in Central Appalachia and it doesn't matter if you're digging metallurgical coal or steam coal.

While demand is stagnate and production has been cut, a source says the biggest problem for CAPP producers is costs and no matter what happens with price or demand costs are going to keep capping CAPP in the knees.

While met coal producers are sweating out the bottoming out of the market, steam coal producers are sweating out whether or not an uptick in demand will even make a difference. The source said costs are anywhere from \$60.00/ to \$70.00/ton at most CAPP operations (some a bit lower, others quite a bit higher) so even if the prices begin to rebound there's the fear sellers will be undercut.

"There's been so much going on the past two years that people forget that a lot of the market that's traditionally gone to Central Appalachia is now wide open," he said. "If demand picks back up we're going to be battling the Illinois Basin and production costs that are half or less than half of what we have. If transportation prices are favorable you have the PRB coming into play.

"Right now we're kind of boxed in."

Of course the source added that "right now" nothing is really happening so the entire exercise is academic. But while prices spent the better part of the past 18 months retreating, costs have continued to climb. Throw in the fact

CAPP coal and its former ace in the hole – favorable sulfur – aren't going to be needed as much and ...

"There's no reason to think that CAPP will be producing at the same rate next year that it was this year and that was down from two years before that," the source said. "When the market comes back, and it will, I don't think you're going to see a big ramp up in production.

"I think if prices start getting up towards \$80.00 (ton) again you're going to see plenty of coal to go around, but I don't think you'll see some of the mines that have closed down being rushed back into production to take advantage."

The source said he's hopeful that the export market will find some equilibrium in the next year or so and that will give CAPP producers two solid bases to be able to work from. Even if Illinois Basin coal can undercut CAPP when it comes to pricing, not every power plant is going to turn that direction.

"I've heard some people say Central Appalachia will become a niche kind of coal and I don't believe that," he said. "But I do believe that if you have a decent base of utilities and a decent export market then you can find a good production level.

"But I think the days of 140 million tons are over unless there's a way to control production costs." □

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24

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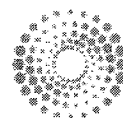
10-K

Annual report pursuant to section 13 and 15(d)

Filed on 02/10/2012

Filed Period 12/31/2011

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____
Commission File No. 001-12079



Calpine Corporation

(A Delaware Corporation)

I.R.S. Employer Identification No. 77-0212977

717 Texas Avenue, Suite 1000, Houston, Texas 77002

Telephone: (713) 830-2000

Not Applicable

(Former Address)

Securities registered pursuant to Section 12(b) of the Act:

Calpine Corporation Common Stock, \$0.001 Par Value

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒

Accelerated filer ☐

Non-accelerated filer ☐

Smaller reporting company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter: approximately \$4,491 million.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 481,338,627 shares of common stock, par value \$0.001, were outstanding as of February 7, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

Designated portions of the Proxy Statement relating to the 2012 Annual Meeting of Shareholders are incorporated by reference into Part III (Items 11, 12, 13, 14 and portions of Item 10)

During the last decade, the supply and demand fundamentals in many regional markets were negatively impacted by the combination of new generation coming on line and a general decline in weather normalized load growth rates due to the economic recession. Although uncertainty exists and there are key regional differences at a macro level, continued economic recovery and thus, corresponding load recovery, with the lack of broad new power plant investments in our key markets should lead to lower reserve margins and higher market Heat Rates. Reserve margins by NERC regional assessment area for each of our segments are listed below:

	<u>2011⁽¹⁾</u>
West:	
WECC	35.1%
Texas:	
TRE	17.5%
North:	
NPCC	28.1%
MISO	24.0%
PJM	32.3%
Southeast:	
SERC	28.4%
SPP	27.9%
FRCC	24.7%

(1) Data source is EIA

The Price and Supply of Natural Gas

Our fuel requirements are predominantly met with natural gas. We have approximately 725 MW of capacity from our Geysers Assets and our expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future as our steam flow decline rates have become very small over the past several years. We also have approximately 371 MW of capacity from power plants where we purchase fuel oil to meet these generation requirements if required, but do not expect fuel oil requirements to be material to our portfolio of power plant assets. Additionally, we have 4 MW of capacity from solar power generation technology with no fuel requirement.

We procure natural gas from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages (especially in extreme weather conditions), transportation availability and supplier financial stability issues can and do occur.

Lower gas prices over the past three years have had a significant impact on power markets. Beginning in 2009, there was a significant decrease in NYMEX Henry Hub natural gas prices from a range of \$6/MMBtu — \$13/MMBtu during 2008 to an average natural gas price of \$4.16, \$4.38, and \$4.03 during 2009, 2010 and 2011, respectively. Natural gas prices in some parts of the country for parts of 2009, 2010 and 2011 were low enough that modern combined-cycle natural gas-fired generation became less expensive on a marginal basis than coal-fired generation. The result was that natural gas displaced coal as a less expensive generation resource resulting in what the industry describes as coal-to-gas switching.

Although some of this lower pricing dynamic can be attributed to the economic recession, the availability of non-conventional natural gas supplies, in particular shale natural gas, has also kept natural gas prices low. Access to significant deposits of shale natural gas has altered the natural gas supply landscape in the U.S. and could have a longer-term and profound impact on both the outright price of natural gas and the historical regional natural gas price relationships (basis differentials). The U.S. Department of Energy estimates that shale natural gas production has the potential of 3 trillion to 4 trillion cubic feet per year and may be sustainable for decades with enough natural gas to supply the U.S. for the next 90 years. Accordingly, there is an emerging view that lower priced natural gas will be available for the medium to long-term future.

The relative price of natural gas can have varying results on our Commodity Margin and liquidity. The impact of changes in natural gas prices differs according to the time horizon and regional market conditions and depends on our hedge levels and other factors discussed below.

Much of our generating capacity is located in California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment) where natural gas-fired units set power prices during most hours or most “peak” hours. “Peak” hours are generally considered between the hours of 7:00 a.m. and 11:00 p.m., with the remaining hours considered “off-peak.” In California and Texas, natural gas-fired units set prices during most hours, although incremental renewable generation and coal-to-gas switching have moderated this dynamic somewhat in off-peak hours over the last year. In the Mid-Atlantic, natural gas-fired units set prices during most peak hours. Outside of our California, Texas and Mid-Atlantic markets, coal-fired power plants tend to set power prices more often.

When natural gas is the price-setting fuel, which is often the case in Texas, California and the Mid-Atlantic, increases in natural gas prices may increase our unhedged Commodity Margin because our combined-cycle power plants in those markets are more fuel-efficient than conventional natural gas-fired technologies and peaker power plants. Conversely, decreases in natural gas prices tend to decrease our unhedged Commodity Margin. In these instances, our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis.

Natural gas-fired combined-cycle units in many markets are now frequently cheaper to dispatch than coal-fired power plants. When coal-fired electricity production costs exceed natural gas-fired production costs, coal-fired units tend to set power prices. In these hours, lower natural gas prices tend to increase our Commodity Margin, since our production costs fall while power prices remain constant (depending on our hedge levels and holding other factors constant).

Where we operate under long-term contracts, changes in natural gas prices can have a neutral impact on us in the short-term. This tends to be the case where we have entered into tolling agreements under which the customer provides the natural gas and we convert it to power for a fee, or where we enter into indexed-based agreements with a contractual Heat Rate at or near our actual Heat Rate for a monthly payment.

Changes in natural gas prices may also affect our liquidity. During periods of high or volatile natural gas prices, we could be required to post additional cash collateral or letters of credit.

Over the long-term, we expect lower natural gas prices to increase coal-to-gas switching, thus enhancing the competitiveness of our modern natural gas fleet and making investments in coal less attractive. Despite these short-term dynamics, over the long run, we expect lower natural gas prices to enhance the competitiveness of our modern, natural gas-fired fleet by making investment in other technologies such as coal, nuclear, or renewables less economic.

Weather Patterns and Natural Events

Weather could have a significant short-term impact on supply and demand for power and natural gas. Historically, demand for and the price of power is higher in the summer and winter seasons when temperatures are more extreme, and therefore, our unhedged revenues and Commodity Margin could be negatively impacted by relatively cool summers or mild winters. Additionally, a disproportionate amount of our total revenue is usually realized during the summer months of our third fiscal quarter. We expect this trend to continue in the future as U.S. demand for power generally peaks during this time.

Operating Heat Rate and Availability

Our fleet is modern and more efficient than the average generation fleet; accordingly, we run more and earn incremental margin in markets where less efficient natural gas units frequently set the power price. In such cases, our unhedged Commodity Margin is positively correlated with how much more efficient our fleet is than our competitors’ fleets and with higher natural gas prices. Efficient operation of our fleet creates the opportunity to capture Commodity Margin. However, unplanned outages during periods when Commodity Margin is positive can result in a loss of that opportunity. We measure our fleet performance based on our operating Heat Rate and availability factors. The higher our availability factor, the better positioned we are to capture Commodity Margin. The lower our operating Heat Rate compared to the Market Heat Rate, the more favorable the impact on our Commodity Margin.

Regulatory and Environmental Pressures

We believe that, on a net basis, we will be favorably impacted by regulatory factors including those described below, given the characteristics of our power plant portfolio:

- An increase in power generated from renewable sources could lead to an increased need for flexible power that many of our power plants provide to protect the reliability of the grid; however, risks also exist that renewables have the ability to lower overall wholesale prices which could negatively impact us. Significant economic and reliability concerns for renewable generation have slowed their growth in 2011 and 2010 compared to 2009, but we expect that renewable market penetration will continue to be assisted by state-level renewable portfolio standards.

25

Seeking Alpha ^α

Exelon Management Discusses Q2 2012 Results - Earnings Call Transcript

Executives

JaCee Burns

Christopher M. Crane - Chief Executive Officer, President, Member of The Board of Directors and Member of Generation Oversight Committee

Jonathan W. Thayer - Chief Financial Officer and Executive Vice President

Kenneth W. Cornew - Executive Vice President, Chief Commercial Officer, Chief Executive Officer of Constellation and President of Constellation

Stacie M. Frank - Vice President of Investor Relations

Anne R. Pramaggiore - President of ComEd and Chief Operating Officer of ComEd

Joseph Dominguez - Senior Vice President of Federal Regulatory Affairs, Public Policy, State Governmental Affairs & Communications

Duane M. DesParte - Principal Accounting Officer, Vice President and Corporate Controller

William A. Von Hoene - Executive Vice President of Finance & Legal

Denis P. O'Brien - Executive Vice President, Chief Executive Officer of PECO Energy, President of PECO Energy and Director of PECO

Analysts

Greg Gordon - ISI Group Inc., Research Division

Stephen Byrd - Morgan Stanley, Research Division

Steven I. Fleishman - BofA Merrill Lynch, Research Division

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

James L. Dobson - Wunderlich Securities Inc., Research Division

Brian Chin - Citigroup Inc, Research Division

Paul B. Fremont - Jefferies & Company, Inc., Research Division

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Ali Agha - SunTrust Robinson Humphrey, Inc., Research Division

Jonathan P. Arnold - Deutsche Bank AG, Research Division

That was the best part of \$400 million and then the ICC stuff is \$75 million or so?

Christopher M. Crane

The working capital element related to the ICC order is \$75 million.

Operator

Your next question comes from the line of Julien Dumoulin from UBS.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

So first with regards to BGE, I noticed you guys filed this rate case late last week. I'd be curious, to what extent do you expect kind of status quo your ability to earn your ROE next year under these new rates just kind of from a rate lag perspective? And then secondly, is there any chance given some of the reliability standards in the state to pursue any kind of quasi-trackers? Is there any outlook for that at all?

Christopher M. Crane

We -- the filing is based off of our desire for the ROE. And I think we've done a good job on stating the basis for that in the filing. So we'll proceed on that front. BGE has some room to make up, to catch up on earnings. As you know, when we announced the intention for our merger, we had to hold BGE out of their rate case. So that's caused some damage. And then there's with the timing and the recovery. But we fully expect to state our case and obtain those numbers. Ken, you want to talk about the Commission's philosophy on riders in Maryland and the potential of that?

Kenneth W. Cornew

Sure, and there's no question that Maryland Commission has not been particularly amenable to forward-looking adjustments. They didn't support any of those in the recent cases. However, we do think we have a compelling reason for proposing some of those. And then in parallel with that, we are still looking at opportunities to work with the Maryland legislature. We had some success in a, what was called the STRIDE Bill, looking at gas safety-related investments, which we almost got across the finish line, and we're going to be reintroducing that again. So we're going to be working both sides, both the legislative and the regulatory process.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Great. And then on the ExGen side, just to be curious, we've seen some shifts in power basis, 80 Hub, NiHub and perhaps, more interestingly, towards the East. How structural are some of these changes as we are thinking about it? Or are they due to more temporary type item?

Kenneth W. Cornew

Yes, Julien. And clearly, spot-basis figures have dropped significantly and it really is explained, in my mind, by coal and gas competition. So a significant amount of basis in the past has been driven by cheaper power prices in the Midwest, cheaper plants and higher costs and a higher heat rate used in the East. Now as gas and coal competition occur, those basis numbers drop. I think that's the main reason we've seen a squeeze in basis. I don't think there are major structural changes that are driving spot basis and forward basis right now. Obviously, with coal retirements coming in 2015 and some reinforcement of the grid, there are going to be some changes.

Operator

Your next question comes from the line of Jay Dobson.

James L. Dobson - Wunderlich Securities Inc., Research Division

26

Wednesday, March 21, 2012 5:01 PM ET  Exclusive

CEOs caution against overreliance on gas-fired power, stress diversification

By Jonathan Crawford

At a March 20 forum examining challenges facing the electric power sector, industry leaders cautioned against a headlong rush into constructing natural gas-powered generation, stressing the need for diversified portfolios to hedge against potential future price increases and other risks.

"There is still a lot of uncertainty, at least in the minds of most of our CEOs, about natural gas," said Mark Kinevan, vice president of energy trading at The Energy Authority Inc., at the EnergyBiz Leadership Forum held in the Washington, D.C., area. "Diversification of the resource base is one key strategy we see a lot of our members using to help protect against uncertainty."

With its prices plunging, production from shale gas reserves surging, and with a cleaner emissions profile, natural gas has emerged as the go-to resource for a number of companies looking to transition away from coal-fired power.

"Because the capital costs [compared to nuclear and coal-fired power plants] are much cheaper and the marginal costs are pretty comparable, it is clearly the fuel of choice for the near future," said forum panelist Nick Akins, president and CEO of American Electric Power Co. Inc.

While U.S. demand for natural gas has been relatively slack, Kinevan argued that if the U.S. enters the global market with LNG exports, chemical producers ramp up their use of the fuel as a feedstock, and a wave of gas-fired generation comes online, prices could firm up. "I think we are going to be surprised by the strength of potential natural gas demand five years down the road," he said.

Although some analysts project that natural gas prices will climb into a range of \$5 to \$7/MMBtu in 10 years, Kinevan stressed that past cycles show that prices could hover near \$10/MMBtu in the long term.

As evidence of the uncertainty, he pointed to the potential difficulty of entering into longer-term supply contracts. "If you want to contract natural gas for 20 years, good luck trying to find a producer who's going to do that. [And even] if you do find a producer, they may not be around for that long to do that," he said.

Akins said gas-fired generation will represent only a portion of the plants that are replacing the mostly older, smaller coal-fired units being retired. Out of the nearly 6,000 MW of coal-fired capacity that AEP is planning to retire, he said, about 1,500 MW will be replaced with units running on natural gas. The amount of AEP's generation to be derived from coal, he said, is expected to drop down to 52% from 65%.

"In the end, we will still have a large portion of our generation that is from coal-fired generation," he said. "We need everything. That is clear for us going forward."

Duke Energy Indiana Inc. President Douglas Esamann, another panelist, said his company is going to take a similar tack. While natural gas is a good addition to the company's energy portfolio, it should only be a part of the mix, he said.

"I think diversity is still important," Esamann said. "I don't think we are going to be putting all of our eggs in the natural gas basket. We have a number of irons in the fire, and I think that's how we are going to continue to look at this."

For Dominion Resources Inc. Chairman, President and CEO Thomas Farrell II, one of the benefits of resource diversification is the ability to keep load rates steady for a long period of time. He noted that Dominion counts as its fuel sources a lot of nuclear, as well as coal, hydropower, oil, wind, biomass and natural gas. He added that if coal and nuclear plants are only replaced with natural gas, "20 years from now my successor will be worried about gas prices."

PG&E Corp. Chairman, President and CEO Anthony Earley Jr. maintained that it will require prudence on the part of authorities for the industry to avoid becoming overly dependent. "Hopefully regulators will be far-sighted enough to say we do need to build some nuclear plants in this country," he said. "But it does take far-sighted regulators, because the short-term gas prices are going to be low."

Duke Energy Indiana is a subsidiary of Duke Energy Corp.

27

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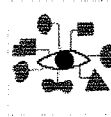
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BUSINESS | April 30, 2012, 6:57 p.m. ET

Utilities Give Coal the Heave-Ho

Power Plants Abandon Longtime Staple for Generating Electricity as Price of Natural Gas Plummets

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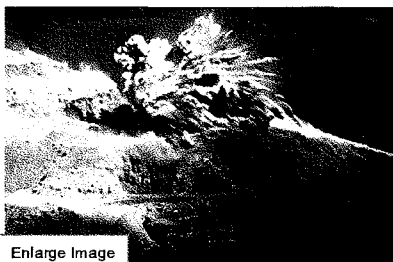
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By REBECCA SMITH

U.S. electric utilities are renegotiating coal contracts and finding other ways to reduce coal deliveries as a mild winter and competition from less-expensive natural gas combine to weaken demand for power plants' longtime staple fuel.

Coal consumption by power generators fell 18.8% in the fourth quarter from the preceding quarter and 9.4% from the fourth quarter of 2010, the Energy Information Administration said last week.



Enlarge Image

Getty Images

Coal consumption fell 9.4% in the fourth quarter from a year earlier as power generators sought cheaper fuel. Above, a Virginia mining operation.

The agency hasn't calculated first-quarter coal use yet. But utilities have indicated that they are shifting power production to natural gas, the price of which recently dipped below \$2 per million British thermal units, roughly half what it was a year ago.

Xcel Energy Inc. XEL -0.42% which owns utilities in eight states, typically entered into advance coal contracts sufficient to meet the company's entire annual need. Now, "we're keeping a

more open position" because Xcel is using less coal and more natural gas, said Susan Arigoni, the company's vice president of fuels. The Minneapolis-based company said it expects to leave about one-fifth of its anticipated coal purchases open—taking its chances on short-term market prices—to preserve the option of buying other fuels.

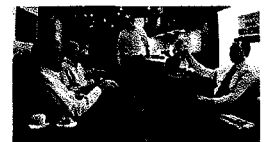
Xcel in April told Texas residential customers that it will cut the average electricity bill by 5.5%, about \$5 a month for the average customer, due to declining fuel costs. The company also expects to cut utility bills 13% to 15% for residential and small-business customers in Colorado.

Coal suppliers are adjusting as best they can. Peabody Energy Corp. BTU +1.00% Chief Executive Greg Boyce has estimated that coal demand by the power industry could drop 100 million tons, or about 10%, this year. The St. Louis company, one of

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More in Business

the largest coal producers, is slowing production.

Progress Energy Inc., which generates electricity for more than three million customers in North Carolina, South Carolina and Florida, is renegotiating coal delivery schedules and amounts. The Raleigh, N.C., company also is selling coal to exporters, sometimes at a loss, to control inventories.

Duke Energy Corp. ([DUK +0.05%](#)) recently told Indiana regulators that it has talked with long-term suppliers about deferring or canceling coal deliveries this year because it expects to burn 40% less coal in Indiana than in 2011.

Coal inventories for the Charlotte, N.C., utility rose in Indiana this winter, when they typically decline. The company has lined up additional areas to store excess coal, fearing it could run out of space. It can't reject shipments because that could expose the utility to breach-of-contract claims.

Not all utilities are finding that the shift in fuel is reducing their costs.

American Electric Power Co.'s ([AEP +0.10%](#)) fuel bill barely budged in the first quarter, even though it was generating 71% of its electricity from coal, down from 81% a year earlier. That is because its coal costs rose to an average of \$49 a ton under long-term contracts from \$45. Its natural-gas costs, meanwhile, dropped to \$2.80 per million BTUs from \$4.63 a year earlier.

The coal contracts, which are expected to satisfy the Ohio utility's entire coal needs for this year and 80% for next year, could protect customers if natural-gas prices jump.

But few people in the industry expect that to happen soon. Average forward prices on natural gas aren't expected to surpass \$4 per million BTUs on the New York Mercantile Exchange until 2016.

Write to Rebecca Smith at rebecca.smith@wsj.com

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SNL Daily Coal Report

June 25, 2012 Monday

SECTION: Exclusive

LENGTH: 1171 words

HEADLINE: As layoffs mount, anger boils over in Appalachian coal country

BYLINE: Dan Lowrey

HIGHLIGHT:

Kentucky's elected leaders reacted with disappointment and frustration at Arch Coal's plan to lay off hundreds more Appalachian coal miners, with Republicans blaming the Obama administration's anti-coal regime for crippling the economy of the country's third-largest coal-producing state.

BODY:

Kentucky's elected leaders reacted with disappointment and frustration at Arch Coal Inc.'s plan to lay off hundreds more Appalachian coal miners, with Republicans blaming the Obama administration's anti-coal regime for crippling the economy of the country's third-largest coal-producing state.

"This is another sad example of the results of the Obama administration's continued war on coal," Rep. Ed Whitfield, R-Ky., said in a June 21 news release. "It is troubling to me that President Obama continues to put our economy at risk at a time when it is most vulnerable by issuing regulations that cause companies to close plants, which will mean lost jobs and which will ultimately raise electricity prices on consumers."

"The EPA's outright assault on coal is already having a destructive effect on Kentucky's economy, and we will likely see more coal-fired power plants closed and more mining operations shut down due to EPA's outrageous expansion of regulations, not to mention the impact of lawsuits filed by environmental groups with the support of the Obama Administration," Whitfield added.

Arch on June 21 announced plans to idle several operations and cut production at other mining complexes in Appalachia in response to an "unprecedented downturn in demand for coal-based electricity." Arch said its subsidiaries will close three higher-cost thermal mining complexes and associated preparation plants; temporarily idle the Flint Ridge complex; and curtail production at other operations in Kentucky, Virginia and West Virginia, resulting in a workforce reduction of about 750 full-time employees.

29

Patriot Bankruptcy May Leave Peabody Liable for Expense

By Sonja Elmquist - Jul 10, 2012

Patriot Coal Corp.'s bankruptcy may leave competing U.S. mining companies Peabody Energy Corp. (BTU) and Arch (ACI) Coal Inc. liable for expenses related to Patriot operations they once owned.

Peabody, the largest U.S. coal producer ranked by sales, may be responsible for liabilities for the treatment of black lung disease that were assumed by Patriot when it was spun off from Peabody in 2007, according to a February filing. Peabody may be responsible for the liabilities, which are expected to be less than \$150 million, should Patriot be unable to fund them, according to the filing.

Arch, the fourth-biggest producer, may have to cover contracts from Patriot unit Magnum Coal Co., according to Arch filings.

Patriot filed for protection in U.S. Bankruptcy Court in Manhattan yesterday. The St. Louis-based company, whose Chapter 11 petition listed \$3.57 billion in assets and \$3.07 billion in debts, is the biggest casualty so far of the slump in the U.S. coal industry, which has cut tens of millions of tons of production following a mild winter and after natural-gas prices dropped to their lowest in a decade.

Patriot's reorganization may accelerate the closing of some of its high-cost Appalachian mines, reducing the region's surplus of production, Curt Woodworth, a New-York based analyst with Nomura Securities International Inc., said in a note today.

Arch Guarantee

Magnum was acquired by Patriot in 2008 from investors including hedge fund ArcLight Capital Partners LLC. Three years earlier, Magnum had bought mines from Arch, which guaranteed some of Magnum's obligations to supply coal, according to Arch filings.

If Patriot fails to deliver 10 million tons from Magnum under contract, Arch will have to do so, said Lucas Pipes, an analyst at Brean Murray Carret & Co. in New York. The deliveries would cost Arch less than \$100 million, he said, citing conversations with the company.

Kim Link, a spokeswoman for Arch, and Vic Svec, a spokesman for Peabody, didn't immediately

respond to messages seeking comment.

The New York Stock Exchange announced today it would stop trading in Patriot shares and begin proceedings to delist them.

Other U.S. coal stocks fell. James River Coal Co. (JRCC) slid 25 percent to \$2.16 in New York, the biggest decline since Dec. 1, 2008. Arch fell 8.4 percent and Peabody 3.7 percent.

Patriot has an \$802 million loan to finance its operations in bankruptcy and said yesterday it expects mining and customer shipments to continue. The loan arranged through Citigroup Global Markets Inc., Barclays Bank Plc, and Merrill Lynch, Pierce, Fenner & Smith Inc. still requires court approval.

Standard & Poor's Ratings Services said today it cut its rating on Patriot to D, its second-lowest ranking, from CC.

To contact the reporter on this story: Sonja Elmquist in New York at selmquist1@bloomberg.net

To contact the editor responsible for this story: Simon Casey at scasey4@bloomberg.net

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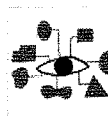
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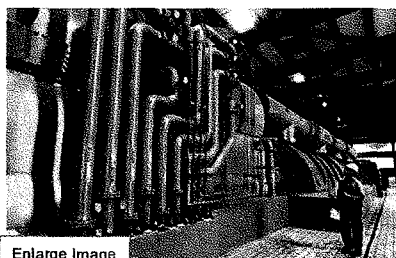
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By KRIS MAHER

U.S. coal companies, whose stocks are down 30% over the past three weeks, are fighting not only the latest market swoon but inroads from natural gas, heightened environmental regulations and higher costs.

This summer's heat wave should have made the commodity hot in the East, but it didn't. Utilities drew down coal stockpiles but also favored lower priced and cleaner natural gas in some regions, sending prices of thermal coal used by utilities lower in the East. Meanwhile, small coal-fired power plants along rivers in Ohio and elsewhere are slated to close, due to tougher emission standards.



Enlarge Image

Bloomberg News

Coal is expected to cede market share to natural gas. Above, Utah's Intermountain Power Plant, one of the nation's largest coal-fired plants.

Competition from natural gas is crimping coal demand nationwide. In the first quarter, natural gas and other factors, such as flooding that disrupted coal shipments in the Midwest, helped push the share of electricity generated by coal to the lowest level in 30 years, according to the Energy Information Administration.

Coal is expected to cede more market share to natural gas, in what analysts say could be a permanent shift. In the first quarter of this year, coal fueled 46%

of the nation's electricity, down three percentage points from a year earlier and down six points from the first quarter of 2008, according to the EIA. The loss of market share is most acute in Central Appalachia, a heavily mined region where it costs more to mine thinner coal seams.

Companies are still expected to mine 1.067 billion short tons of coal in 2011, the vast majority of it thermal coal used by utilities, compared with 1.085 billion tons last year, according to the EIA. The agency forecasts total coal consumption will be down about 2% this year.

"It's definitely a struggle for coal to maintain its historical market share," said Paul Forward, an analyst with Stifel, Nicolaus & Co.

Consolidation from three recent mergers and increased exports of thermal and

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metallurgical coal used by steelmakers should help the industry in coming months, say analysts. But shutdowns of some thermal coal mines are expected, particularly in Central Appalachia, where mining has helped buoy the local economy and kept miners working.

"Central Appalachia has been in a steady state of decline and probably will continue to decline for a while," said Kevin Crutchfield, CEO of [Alpha Natural Resources Inc.](#)

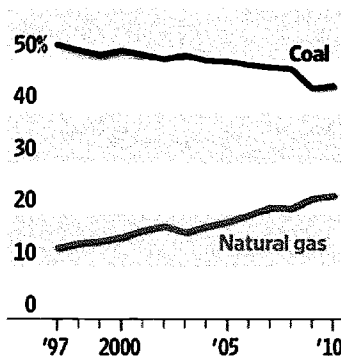
([ANR +1.53%](#)) in a recent interview. Alpha, which acquired Massey Energy in June, is conducting a company-wide review to identify money-losing operations and could close or sell some thermal coal mines, he said.

Mr. Crutchfield said he expects annual production in the region to fall to between 150 million tons and 170 million tons, from the current 180 million tons. He attributed some of that decline to coal seams that are thinner and harder to reach, which increases costs, and to the development of the Marcellus Shale, a massive natural-gas deposit stretching across parts of Ohio, West Virginia, Pennsylvania and New York.

Alpha, [Patriot Coal Corp.](#), [Consol Energy Inc.](#), ([CNX +1.27%](#)) and [James River Coal Co.](#), ([JRCC +3.61%](#)) which have operations in Central Appalachia, all reported higher costs in the second quarter. Meanwhile, the contract price for thermal coal from that region for delivery in 2012 is down about 6% since May.

Power Move

Net generation of electricity by source as a percentage of total generation



Source: Energy Department

At Alpha, costs per ton jumped 17% in the second quarter across its operations to \$70.84 a ton, from a year ago. The increases at other companies helped drive down their share prices as the broader market declined in the past few weeks.

The higher costs for coal companies "were a big surprise... that encouraged some of this selling off of these stocks," said Mr. Forward of Stifel, Nicolaus.

At the same time, new federal rules restricting impacts to streams from mining in six Eastern states have put more pressure on thermal coal, which is often mined from the surface with explosives and earth-moving machines. Federal emissions regulations intended to reduce sulfur dioxide and nitrogen oxide that

were announced in July have led utilities to say they will close coal-burning power plants in Ohio, Georgia and Texas, among others.

Coal companies are focusing more on mining higher-margin metallurgical coal used to make steel and boosting exports. Alpha, the nation's biggest producer of that grade of coal, had an average realized price of \$176 a ton in the second quarter, up 50% from a year earlier.

Net exports industry-wide are expected to rise nearly 30% this year to 79.8 million tons, including thermal and metallurgical coal, according to the EIA. Higher exports of thermal coal are expected to head to Europe, where nuclear plants have been idled, and to China and India to feed power plants and steel mills.

In China, coal consumption rose 19% in July, from a year ago, while coal imports reached 17 million metric tons (18.7 million short tons) in the month, which may be a record, according to Vic Svec, a senior vice president at [Peabody Energy](#) ([BTU +1.00%](#)) Corp. in St. Louis. "The Asia-Pacific markets remain extremely strong," Mr. Svec said.

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31

Railroads

Mapping Utility Plants to Rail Coal Volumes -- Impact of Plant Retirements May Be Largely Realized in 2012

Coal volumes have been exceptionally weak for the US railroads in 2012 due to a combination of an unusually mild winter, high stockpiles, and very low natural gas prices. In this report we provide a framework for the impact of future coal plant retirements based on current utility plans and we also take a look at which coal consuming regions have the greatest risk from share loss to natural gas. Our analysis indicates that if the current run rate of coal volumes continues, most of the impact to rail coal volumes from plant retirements will essentially be pulled forward into 2012. For CSX and NSC we are less optimistic about a future bounce back in utility coal volumes, but after what may be a period of sharp y/y declines in 2012 for UNP, we believe there may be more room for PRB volumes to bounce back somewhat in 2013 / 2014.

- **Impact from plant retirements is significant; timing is later for UNP.** We have analyzed more than 117 power plants that have been identified by utilities to be retired over the next several years to show the impact to the individual railroads from plant retirements. Our analysis indicates that due to plant closures in 2012 and beyond, CSX would lose 25 mm tons of coal and NSC and UNP would lose 21 mm tons. Timing for the plant retirements is generally skewed to 2015 and beyond for UNP, while the planned retirements for CSX and NSC are also significant in 2012 / 2013. We note that UNP's utility coal tonnage in 2011 was about 250 mm, while CSX and NSC had 109 mm and 122 mm tons of utility coal.
- **Current run rate implies retirement impact is largely realized in 2012.** At our conference in mid March, CSX indicated its 1Q12 utility tons were down 25%-30% y/y and NSC's utility tons were off ~17% y/y in 1Q. Assuming that the 1Q utility tonnage levels persist throughout the year, CSX would lose 27 mm tons in 2012, NSC's utility coal would be 17 mm tons lower and UNP would lose ~43 mm tons (based on the run rate in March). This would represent a slight overshoot for CSX and a slight undershoot for NSC relative to our estimate of the impact of plant retirements. For UNP the large 43 mm reduction significantly overshoots our estimate of a retirement impact of 21 mm tons. This implies that UNP could see a modest rebound in coal volumes in 2013 / 2014. We are more cautious about a bounce back in utility coal for the Eastern rails.
- **Boost from coal pricing has been more powerful for NSC & CSX.** At this point, it is difficult to assess the potential rail pricing trend for utility coal looking forward. Looking at data off a 2003 base, it is clear that the Eastern rails have realized a sharper step up in coal transport pricing through 2011. For NSC and CSX, coal revenue / RTM rose 113% and 115% while rev / RTM was up 67% for UNP.
- **Combined cycle gas capacity is greater in the Southeast and Eastern Texas.** While it is challenging to quantify, a review of the coal plant and combined cycle gas plant maps we show in this report clearly points to greater share loss risk of coal to natural gas in the Southeast and Texas. An eventual rise in natural gas prices would likely be more favorable for UNP as the coal fired generation it serves is competitive at lower gas prices than coal plants fired by Eastern coal.

See page 13 for analyst certification and important disclosures.

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Airfreight and Surface Transportation

Thomas R. Wadewitz ^{AC}

(1-212) 622-6461
thomas.r.wadewitz@jpmorgan.com

Michael R. Weinz, CFA

(1-212) 622-6383
michael.r.weinz@jpmorgan.com

Alexander K. Johnson

(1-212) 622-6513
alexander.k.johnson@jpmorgan.com

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Key Points

Electricity demand fell sharply in the Southeast US

The relatively mild winter in late 2011 / early 2012 (vs. roughly normal winter weather in 2010 / 2011) was a significant driver of the y/y decline in YTD electricity demand. Total electricity generation fell 4.0% y/y in 1Q:12. The Southeast region, which is served by CSX and NSC, fell 8.2% y/y, which is the weakest region overall. We suspect this is contributing to significant weakness in coal demand in the service territory of CSX and NSC. We note that the y/y decline in electricity demand in the western US appears to be somewhat more muted than in the east and the Pacific Southwest (California) is essentially flat y/y. We summarize the regional exposure by the major Class I railroads in the following table. We note that in the territories served by CSX and NSC, 1Q:12 electricity generation is down 4.2%, while the territories served by BNSF and UNP face a 0.9% decline in generation and KSU's served territory is flat y/y.

Table 1: Absolute and Y/Y Change in Electricity Generation (in gWh) through April 12, 2012

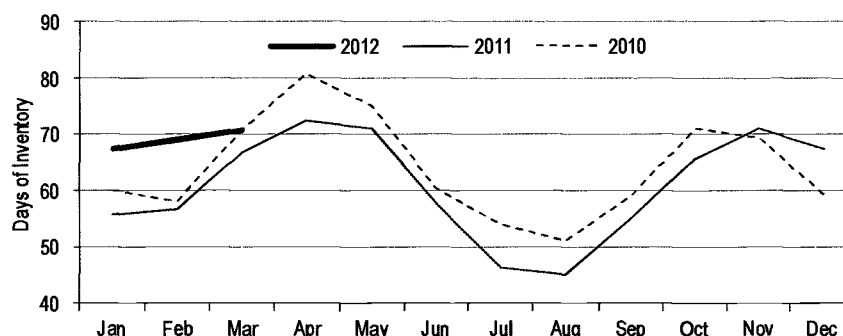
Region	States in the Region	Week of April 12, 2012		1Q:12 Generation		Regional Railroad Exposure				
		Current	Y/Y Chg	1Q:12	Y/Y Chg	CSX	NSC	BNSF	UNP	KSU
New England	CT, ME, MA, NH, RI, VT	2,232	-2.4%	31,632	-5.1%	X	X			
Mid-Atlantic	DE, NY, MD, NJ, part of PA	7,467	-2.2%	107,448	-3.8%	X	X			
Central Industrial	IL, IN, MI, OH, parts of PA, WV, WI, MO	11,759	-1.7%	173,005	-4.4%	X	X			
West Central	IA, KS, MN, NE, ND, SD, parts of WI, MO	5,686	-1.0%	79,203	-5.6%			X	X	X
Southeast	AL, FL, GA, KY, NC, SC, TN, VA, parts of MS, WV	17,883	-4.9%	242,862	-8.2%	X	X			
South Central	AR, LA, OK, TX, part of MS	11,985	10.2%	147,535	3.3%	X	X	X	X	X
Rocky Mountain	AZ, CO, MT, NV, NM, UT, WY, and part of ID	4,169	-1.4%	61,503	-0.9%			X	X	
Pacific Northwest	OR, WA, and part of ID	3,129	-5.3%	44,548	-6.5%			X	X	
Pacific Southwest	CA	5,028	0.9%	67,244	-0.2%			X	X	
Total United States		69,338	-0.7%	954,980	-4.0%	-4.2%	-4.2%	-0.9%	-0.9%	0.0%

Source: Bloomberg.

Coal stockpiles are well above normal

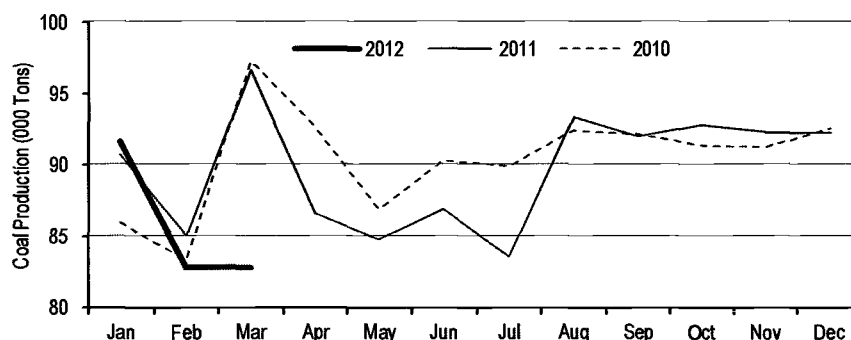
As indicated by the railroads and the utilities, coal stockpiles have been rising given the mild winter, lower electricity consumption, and the low price of natural gas. We illustrate the coal stockpile levels at the utilities in 2010, 2011, and 2012 YTD. In January and February, stockpiles appear to be well above normal as seen in Figure 1 below. Ordinarily, stockpiles would begin to rise in March as coal production picks up and we enter the shoulder months when electricity generation moderates. We note that EIA data (in Figure 2 below) indicates that coal production did not experience a normal pick up in March vs. January and February. As a result, we believe that stockpile levels are less likely to see the sharp sequential rise in March and April that they have typically realized in the past. However, low natural gas prices and coal to gas switching may support a further step up in coal stockpiles.

Figure 1: Coal Stockpile Levels (Measured by Days of Inventory) Are Up Significantly



Source: Energy Information Administration and J.P. Morgan estimates. Note: Actual/preliminary information through January 2012, the most current information available; J.P. Morgan estimates for the following two months provided by the J.P. Morgan utilities analyst, Christopher Tumure.

Figure 2: Monthly Coal Production in Short Tons



Source: Energy Information Administration.

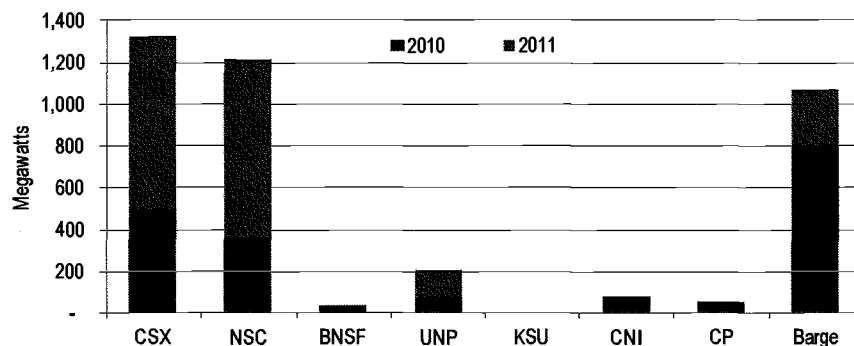
Power Plant Retirement Analysis

We analyzed more than 117 power plants that have been identified by the electric utilities for potential retirement over the next several years. Although these power plants account for more than 36 gigawatts of production, it is unclear exactly how much capacity and when the capacity will actually be retired. Some of the plants may stay online with the addition of scrubbers, while others may be converted to other fuel sources (e.g. natural gas, biomass, wood pellets, etc.) or the plants may be shutdown entirely. Also, the date of official retirement may occur long after a plant is actually idled, which makes it difficult to translate the timing of retirements directly to changes in coal demand. We attempted to determine the source and type of coal burned at each utility for this analysis in order to identify the method of coal delivery and to estimate the heat content of the consumed coal for our tonnage analysis.

Potential coal plant retirements predominantly reside in the Eastern US

As we show in the following figure, plants in the eastern US, served by CSX, NSC, and barge faced the most retirements with a total of 1.9 GW and 2.1 GW closed in 2010 and 2011, respectively.

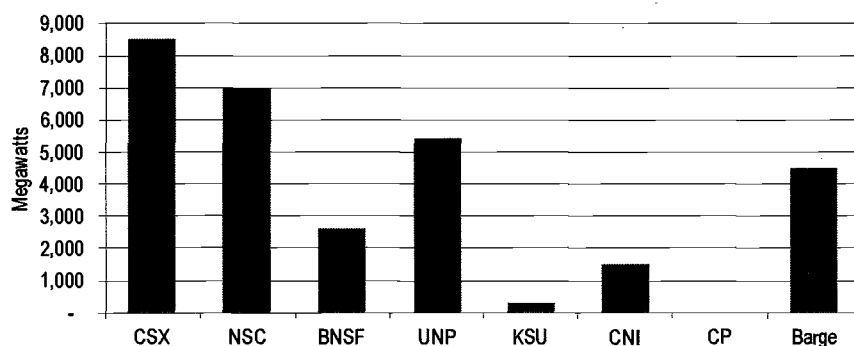
Figure 3: Total Coal-Fired Capacity Closed in 2010 and 2011



Source: Company reports and J.P. Morgan estimates.

Our analysis also shows that in 2012 and beyond, utilities in the eastern US continue to face the most pressure to cut back on coal-fired capacity. We note that CSX and NSC are the primary rail providers in this region, but barge also plays a meaningful role in serving utilities along the Mississippi and Ohio Rivers. Beyond 2012, an additional 29.8 GW of coal-fired capacity is potentially going to be retired. Utility coal is not a meaningful revenue driver for CNI or CP and so their exposure to coal-fired utility retirements is small. KSU has less leverage to coal compared to the large US railroads but at ~14% of revenue in 2011, weak coal can be a headwind. We note that the direct impact on their respective coal businesses from the addition or loss of one customer can be significant because they have a smaller customer base.

Figure 4: Total Potential Coal-Fired Capacity Closing in 2012 and Beyond



Source: Company reports and J.P. Morgan estimates.

Table 2: Estimated Annual Coal Tonnage Needed to Produce 1 MW of Electricity

	Annual Tons per MW
NAPP	2,800
CAPP	2,800
PRB	4,000
Illinois Basin	2,700
Rocky Mountain	3,000
Gulf Lignite	5,000
Foreign Imports	3,000

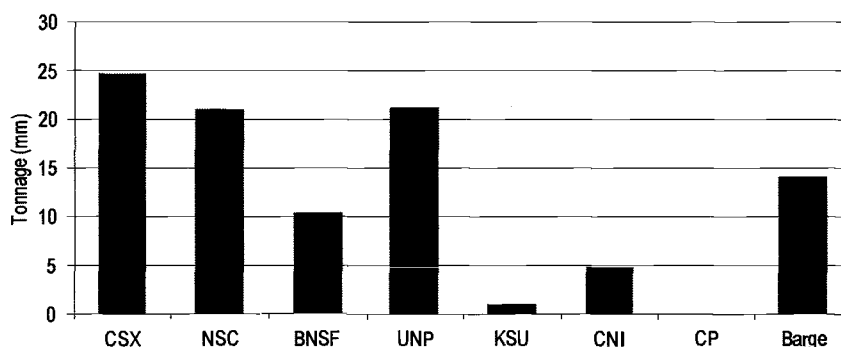
Source: J.P. Morgan estimates.

Potential tonnage impact on the railroads is meaningful for CSX and NSC

While the amount of electricity generation (as measured by megawatts) is important in this analysis, we believe a conversion to tonnage is more appropriate to estimate the approximate impact on each of the railroads from coal plant retirements. Although there can be meaningful differences between power plants in terms of age, technology, and operating efficiency, we approximate the annual coal tonnage required to generate 1 MW of electricity by each type of coal used by power plants in this analysis. We summarize these tonnage assumptions in Table 2. Northern and Central Appalachian coal have higher heat content than the PRB. Although the PRB coal is viewed as more environmentally friendly (it can operate without scrubbers and still meet some of the EPA emission requirements), it does not burn as hot and so more coal needs to be burned in order to produce the same amount of electricity. This is the primary reason that 1 MW of electricity generation requires 4,000 tons of PRB coal per year vs. 2800 tons of Appalachian coal.

By applying these tonnage estimates to our list of potential power plant retirements, we determine that the potential tonnage lost to the railroads is in the 20-25 mm ton range for CSX, NSC, and UNP. We note that UNP hauls more than twice as much utility coal tonnage per year as a CSX and NSC, so the percentage decline for UNP is smaller than that of CSX and NSC. The reason that the chart showing the estimated coal tonnage impact by rail (Figure 5) looks slightly different than the electricity generation chart (Figure 4) is because of our assumptions of coal tonnage per plant. UNP hauls PRB coal, which as we discussed above, requires more tonnage to produce the same amount of electricity. Although the plant exposure in terms of MW is less for UNP than CSX and NSC, the lower heat content of PRB coal results in the need for additional coal tonnage to be hauled by UNP to serve these plants.

Figure 5: Total Tonnage Lost from Potential Coal-Fired Capacity Retirements in 2012 and Beyond



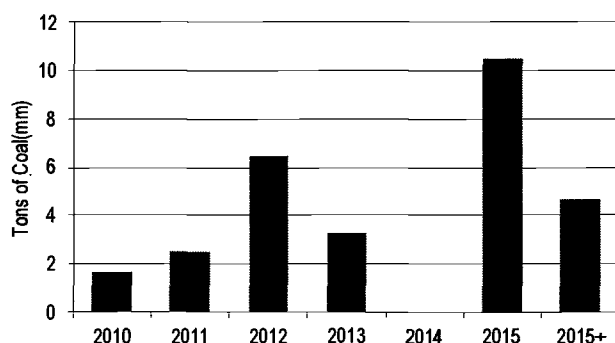
Source: Company reports and J.P. Morgan estimates.

Impact to the eastern rails from plant closures could be meaningful

In Figure 6 and Figure 7 below, we show the profile of potential retirements of coal plants on an annual basis for CSX and NSC, which is based on publicly available information published by the electric utilities. We note that there is a greater concentration of coal-fired power plants in the eastern US states, which are located near the major Appalachian and Illinois coal mining operations and are primarily served by CSX and NSC. Based on our plant-by-plant analysis, we found that there is a spike in the amount of coal capacity slated for retirement in 2012 for both CSX and NSC relative to most other years. CSX also faces a potentially greater step down in coal-fired capacity in 2015. Relative to the 2011 coal tonnage hauled by the

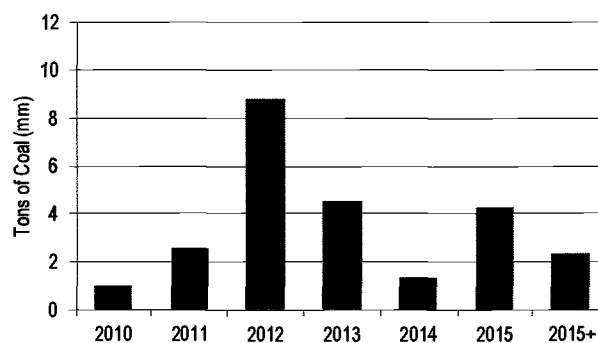
eastern railroads, we estimate that the lost coal volumes from plant retirements in 2012 and beyond would amount to tonnage reductions of as much as 22.7% for CSX and 17.2% for NSC. However, we note that some of these plants may already be idled, will draw down existing inventories, or are not currently operating at full capacity. It is also possible that recent tonnage trends already reflect a meaningful percentage of this capacity that has been taken offline and so the actual impact of these plant shutdowns is likely to be more moderate.

Figure 6: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for CSX



Source: Company reports and J.P. Morgan estimates.

Figure 7: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for NSC

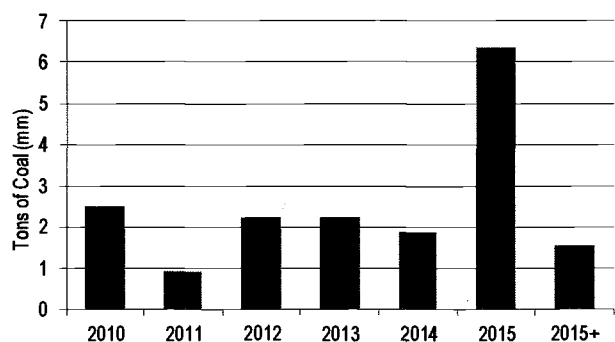


Source: Company reports and J.P. Morgan estimates.

Barge traffic also appears to be affected by closures, but KSU has little exposure

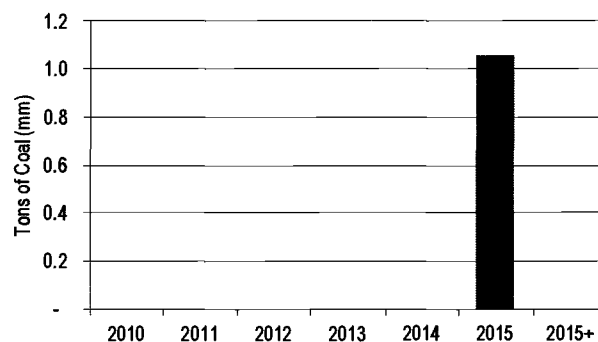
Unsurprisingly, with a large concentration of coal-fired power plants in the eastern US, we found that several utilities served by barge (which may also be jointly served by CSX or NSC) along the Mississippi and Ohio Rivers are potentially going to retire over the next several years. The profile of these retirements is summarized in Figure 8 below. KSU appears to have very little exposure to potential shutdowns as their network runs north to south in the central US and coal is only a modest percentage of their revenue mix. We show that KSU may see a power plant in its territory retire in 2015. Recent coal trends have been weak for KSU but we view the coal impact as a more modest risk for KSU.

Figure 8: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for Barge



Source: Company reports and J.P. Morgan estimates.

Figure 9: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for KSU

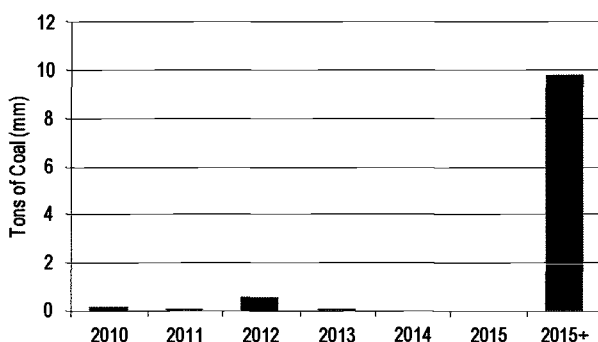


Source: Company reports and J.P. Morgan estimates.

Western railroads have less risk of plant closures in their service territories

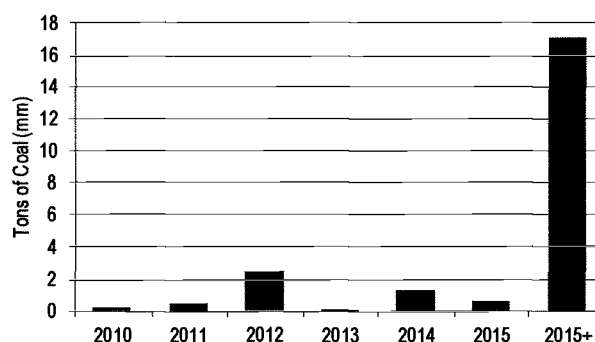
Our analysis shows that there is less risk to utilities served directly by UNP and BNSF retiring over the next few years. The preponderance of potential retirements is expected to occur beyond 2015, but we note that even if all of these retirements are realized, they would represent an 8.5% decline in coal tonnage for UNP. Similarly, BNSF does not appear to have meaningfully exposure in the medium term to plant shutdowns. However, the nature of our analysis made it extremely difficult to determine which power plants in the eastern US served by barge, CSX, or NSC were consuming coal from the Powder River Basin which would originate on the UNP or BNSF network. As a result, our analysis may be somewhat understating the potential impact of power plant closures over the next few years for the Western rails. We note that roughly 21% of UNP's coal revenue in 2011 came from coal which it moved either to a barge facility or to CSX / NSC for consumption in an eastern utility plant.

Figure 10: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for BNSF



Source: Company reports and J.P. Morgan estimates.

Figure 11: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for UNP

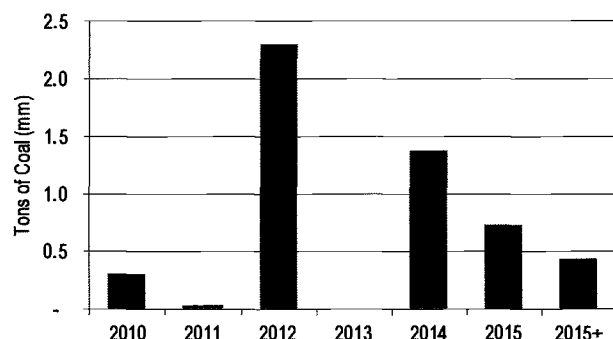


Source: Company reports and J.P. Morgan estimates.

CNI has some exposure to potential coal plant retirements, while CP does not

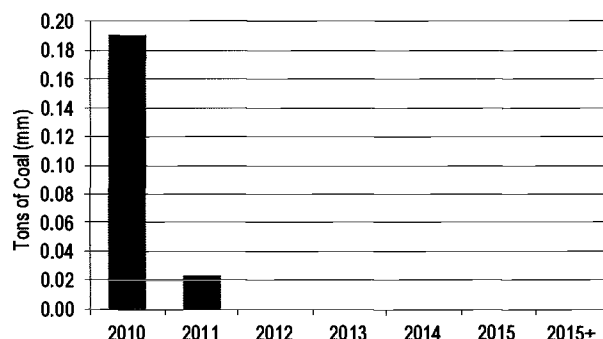
Coal is not a particularly large leverage point for either CNI or CP, but they do serve some utilities in the Midwest (notably in the Illinois Basin and in Wisconsin). CNI served facilities face the greatest amount of potential retirements in 2012 and the pace of retirements moderates in 2014 and beyond. CP's network does not appear to have any retirements currently scheduled beyond those that already occurred in 2010 and 2011, which were had only a modest impact on their coal franchise. CP has the least exposure to utility coal and is primarily levered to metallurgical coal, which is hauled from western Canada for export out of Vancouver.

Figure 12: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for CNI



Source: Company reports and J.P. Morgan estimates.

Figure 13: Potential Annual Coal Tonnage Lost from Coal Plant Retirements for CP

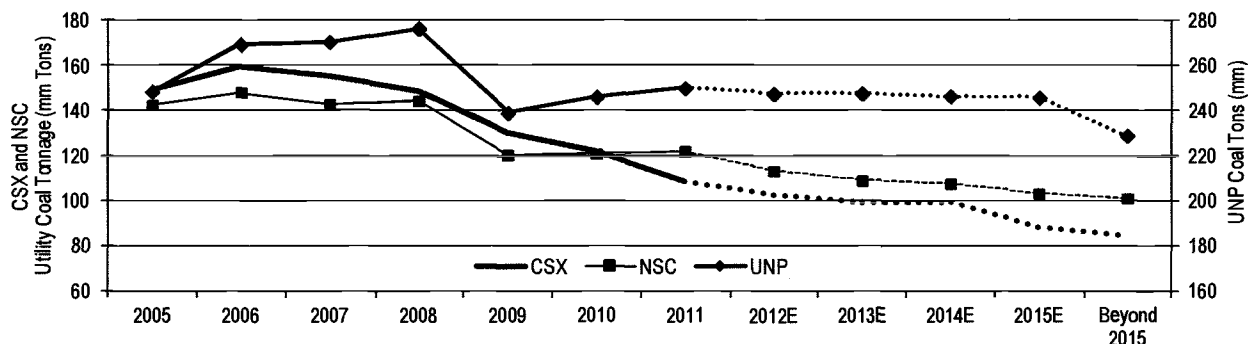


Source: Company reports and J.P. Morgan estimates.

Coal tonnage is unlikely to return to pre-downturn levels in the medium term

Shipments of coal fell with the broader industrial downturn in 2009 for all of the railroads. While shipments picked up somewhat for UNP and NSC, we note that CSX continued to realize y/y declines in its utility coal business. Based on the preceding analysis, we illustrate the potential utility coal tonnage for the three major publicly traded US Class I railroads given the timing of plant retirements. As we discussed above, there can be timing issues between a plant idling and officially retiring and recent volume trends probably already reflect some of this lost coal volume. However, we believe that Figure 14 provides a framework of how coal volumes may look over the next several years. Relative to the 2011 data point, we show that utility coal tonnage beyond 2015 could decline as much as 22.7% for CSX, 17.2% for NSC, and 8.5% for UNP.

Figure 14: Historical Trend of Coal Tonnage Hauled by CSX, NSC, and UNP and the Potential Loss of Coal Tonnage from Utility Retirements



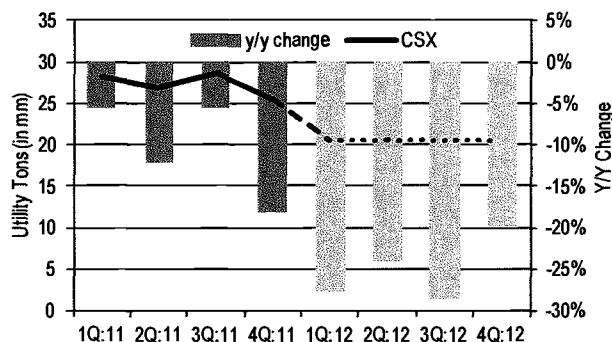
Source: Company reports and J.P. Morgan estimates.

1Q coal trends suggest pull forward of tonnage declines

At the 2012 J.P. Morgan Aviation, Transportation, and Defense conference on March 15, both CSX and NSC provided some detail on their coal tonnage trends during 1Q. CSX indicated that utility coal tonnage was down 25-30% y/y, while NSC indicated that their utility tonnage was down ~17% in 1Q. In the following two charts, we use the respective y/y declines in utility coal for CSX and NCS to imply coal tonnage levels for 1Q:12. We then examined the y/y change in utility coal tonnage implied for the remaining quarters of 2012 by using the 1Q:12 tonnage as the run-rate for the

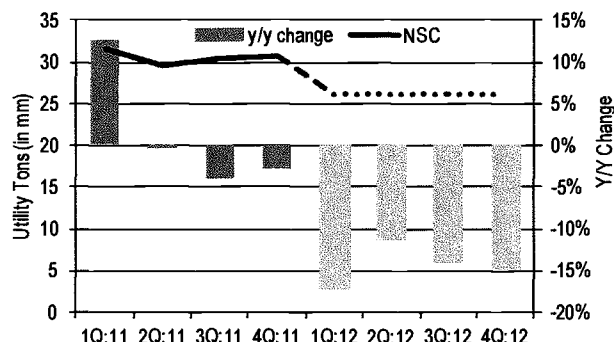
remainder of the year, as indicated by the dotted line on these two charts. These tonnage levels suggest that CSX could see a 25.1% decline in utility tonnage vs. 2011, while NSC would realize a 14.3% decline vs. 2011. UNP's 1Q:12 volumes and the last five weeks of coal carloadings imply that full year coal volumes could contract 17.2% y/y (assuming the most recent 5 week run rate persists through 2012). These full year declines imply a loss of 27 mm tons at CSX in 2012, a decline of 17 mm tons at NSC, and a decline of 43 mm tons for UNP. For the eastern rails, this is a pull forward of the plant retirement impact and for UNP it implies a decline worse than the plant retirement impact.

Figure 15: Quarterly Declines in CSX Utility Coal Tonnage in 2012 Assuming Current Volume Trends Persist



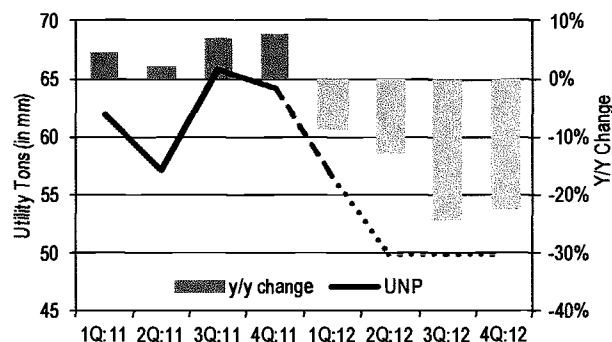
Source: Company reports and J.P. Morgan estimates.

Figure 16: Quarterly Declines in NSC Utility Coal Tonnage in 2012 Assuming Current Volume Trends Persist



Source: Company reports and J.P. Morgan estimates.

Figure 17: Quarterly Declines in UNP Utility Coal Tonnage in 2012 Assuming Current Volume Trends Persist



Source: Company reports and J.P. Morgan estimates.

Table 3: Estimated Coal Tonnage Decline and Y/Y Decline Implied by Recent Coal Volume Trends

	2012 Volume Decline	
	Tonnage (mm tons)	Implied Y/Y Decline
CSX	27.3	-25.1%
NSC	17.4	-14.3%
UNP	42.7	-17.2%

Source: J.P. Morgan estimates.

Coal pricing has risen significantly since 2003

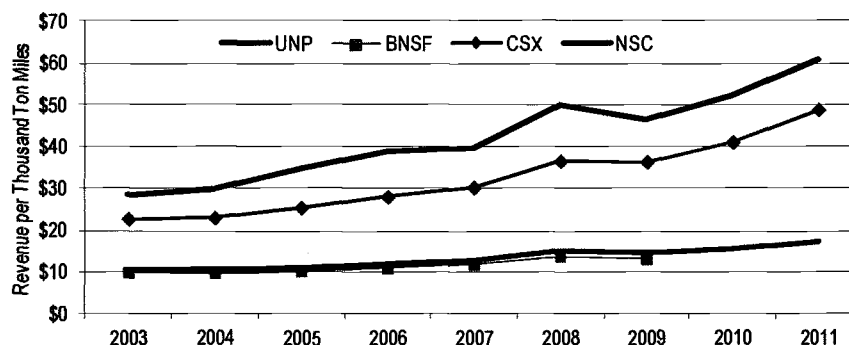
Using 2003 as a base year, which is prior to the ramp up in rail pricing that began in earnest in 2004 and 2005, we estimate that coal pricing (in terms of Revenue per Thousand Revenue Ton Miles) increased 66.6% for UNP, 115.0% for CSX, and 112.7% for NSC. We note that this includes the positive effect of fuel surcharge revenue which we estimate reflects ~33% of the increases based on current fuel prices since there was effectively no fuel surcharge recovery in the 2003 base year.

Table 4: Change in Coal Pricing
(Rev per Thousand RTMs)

	2003-2011 Change
UNP	66.6%
CSX	115.0%
NSC	112.7%

Source: Company reports and J.P. Morgan estimates.

Figure 18: Coal Pricing (Revenue per Thousand Revenue Ton Miles) for the Major Class I Rails

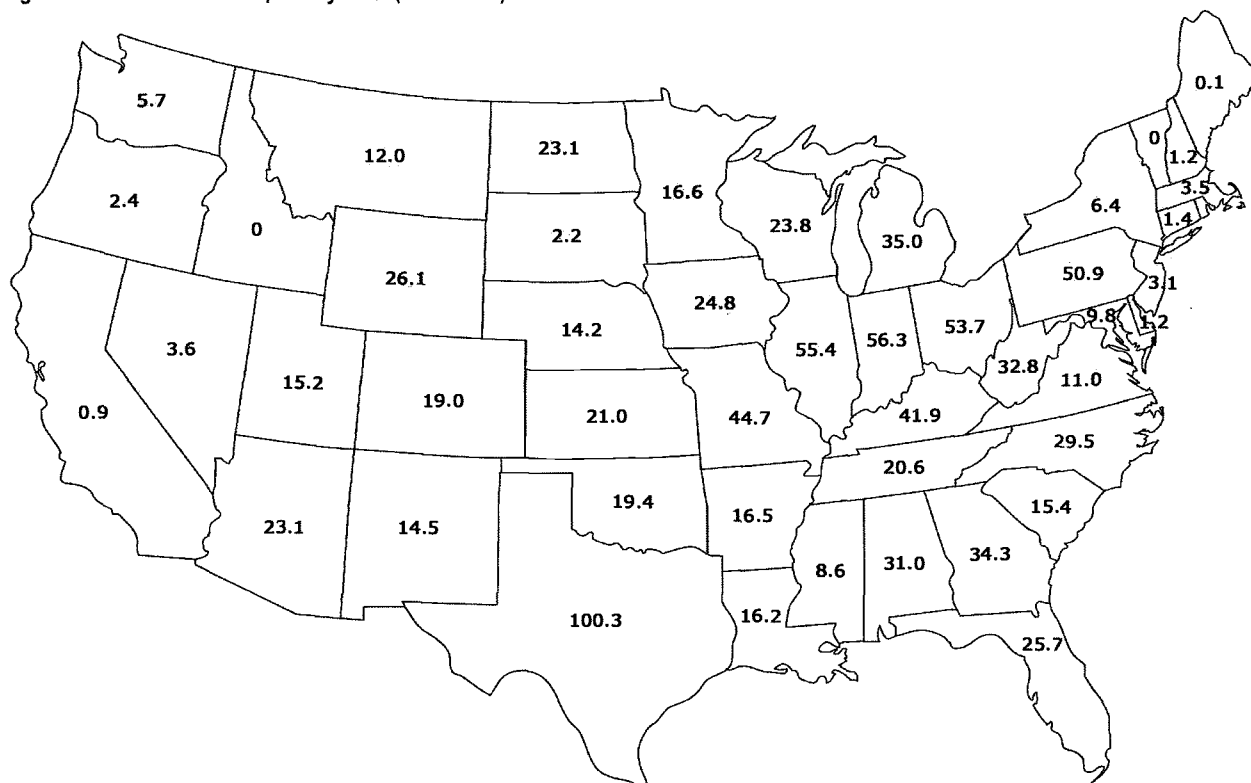


Source: Company reports and J.P. Morgan estimates.

Consumption is greatest in the Eastern US and Texas

In Figure 19, we provide a map of the 2010 coal consumption for each state in the continental US. Coal tends to be consumed in and around the Appalachian states and in the Midwest states located near the Illinois Basin coal mines. PRB coal from Wyoming tends to be spread across the Midwestern states and reaches down into some of the southern states. We note that Texas consumes the most coal of any state.

Figure 19: 2010 Coal Consumption by State (in mm tons)

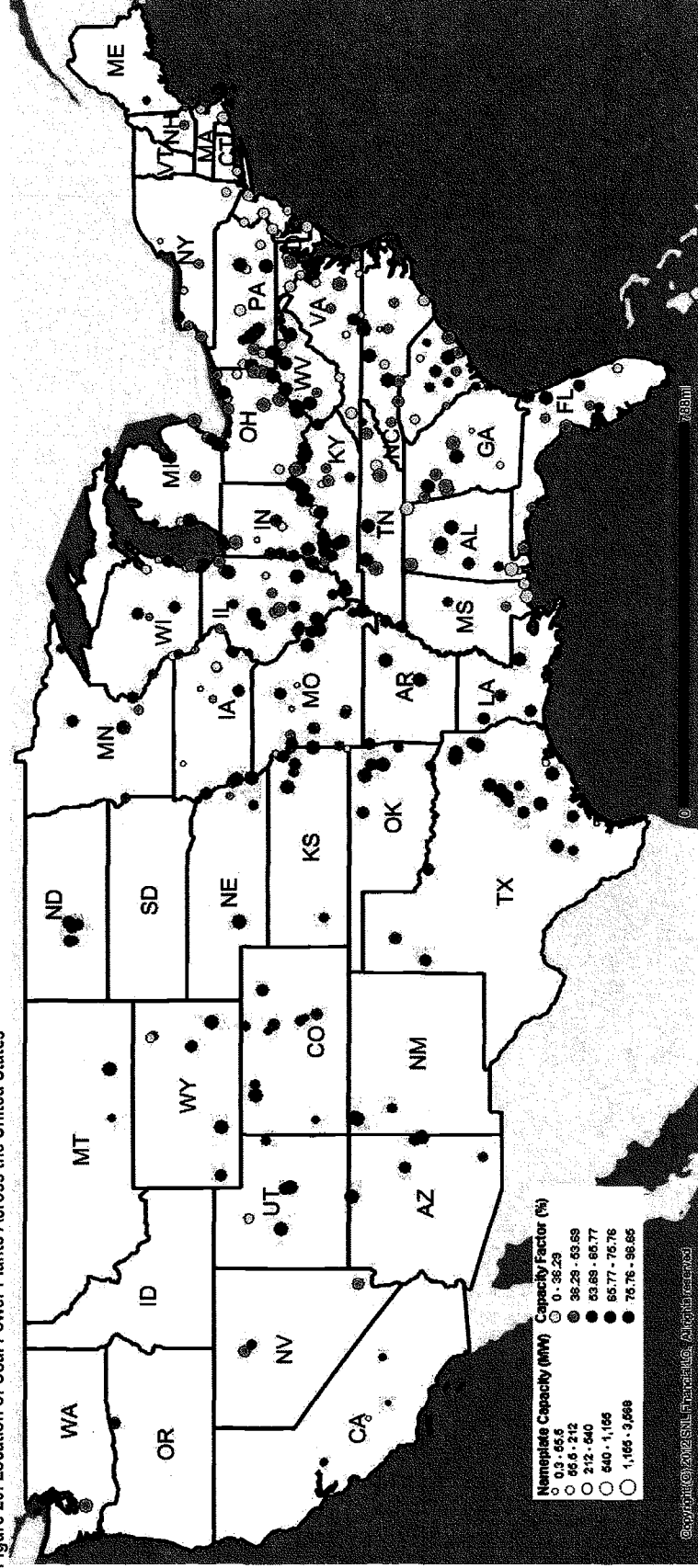


Source: State consumption data is from the Energy Information Administration and the map was created by J.P. Morgan.

Coal plants are located primarily in the Midwest and Eastern US states

As part of our power plant analysis, we thought it would be helpful to show a map with the location of coal-fired power plants across the United States. They appear to be highly concentrated in the Midwest and spread throughout the eastern US. There are also a large number of plants in the Plains states, Rocky Mountains, and in Eastern Texas. There is a notable lack of coal-fired plants in the states along the west coast.

Figure 20: Location of Coal Power Plants Across the United States

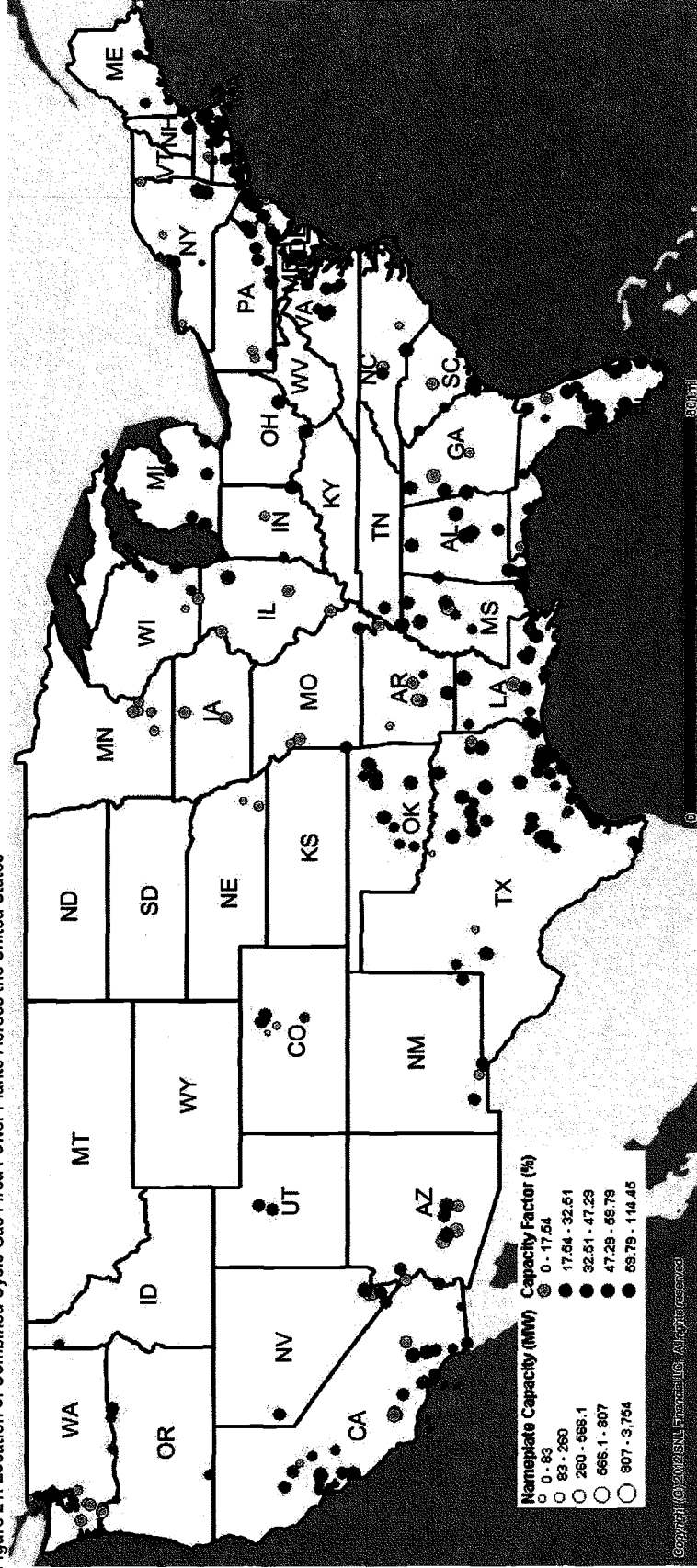


Source: SNL Financial.

Combined cycle gas plants tend to be located along the coasts and in eastern Texas with few plants in the Midwest

In contrast to the previous map, the combined cycle power plants, which are the most competitive vs. coal are located primarily along the coastal states in the Northeast US as well as the Gulf coast states. There is also notable gas-fired capacity in California. Comparing this map to the previous map suggests that there is somewhat limited ability for coal-fired capacity to be replaced entirely by gas. Due to the inefficiencies of electricity transmission, it is not particularly feasible to shut down significant coal-fired plants in the Midwest in exchange for gas-fired plants along the coasts. As a result, we believe that the states in the Southeast are the most likely to face coal to gas switching at utilities, while there is limited capability to switch in states such as Ohio, Indiana, and Illinois where there are very few gas-fired plants.

Figure 21: Location of Combined Cycle Gas Fired Power Plants Across the United States



Source: SNL Financial.

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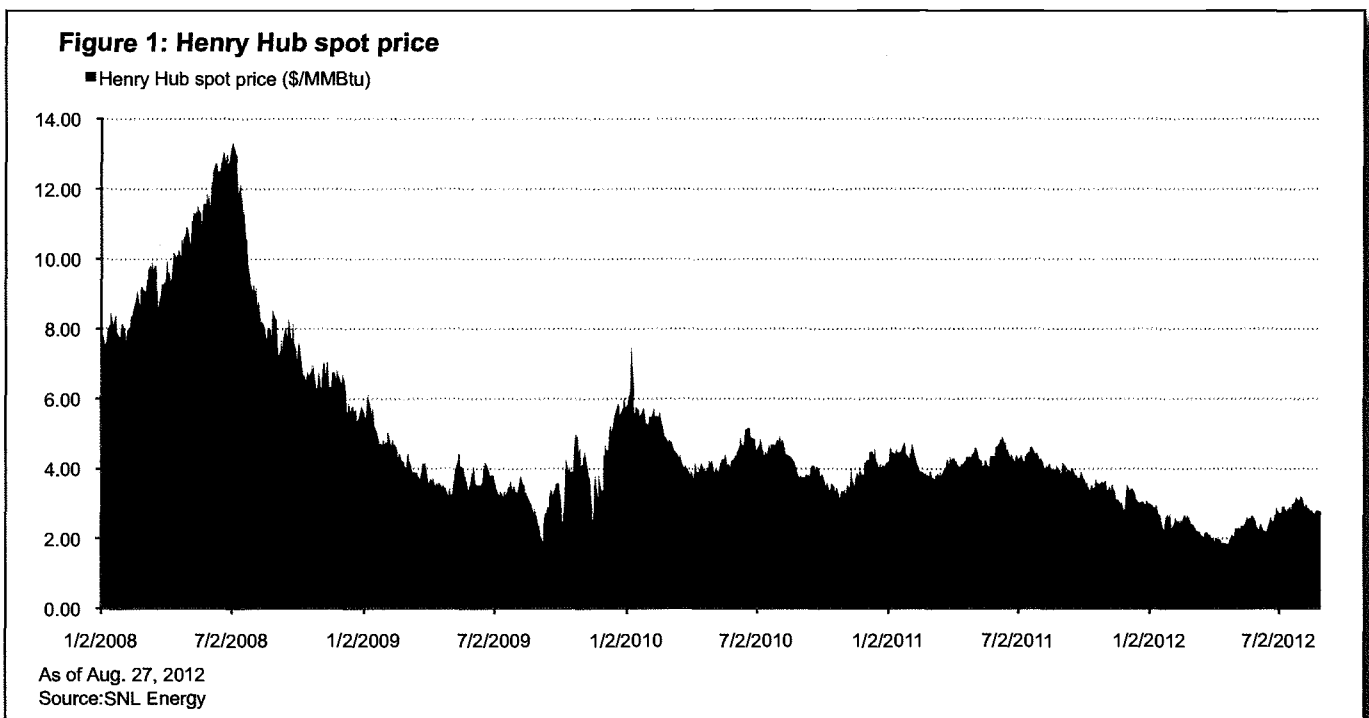
Coal to Gas Switching

Dispatch competition between U.S. coal and natural gas plants has continued in 2012 and remains a key consideration for energy markets. Since SNL Energy's last analysis in May, there has been some strengthening in the natural gas forward curve, working to take pressure off of coal plants in some markets. In the near term, however, natural gas prices look to remain well within ranges conducive to economic displacement of coal volumes in several markets. SNL Energy explores coal and natural gas market fundamentals to estimate potential displacement for the remainder of 2012.

Natural gas market environment

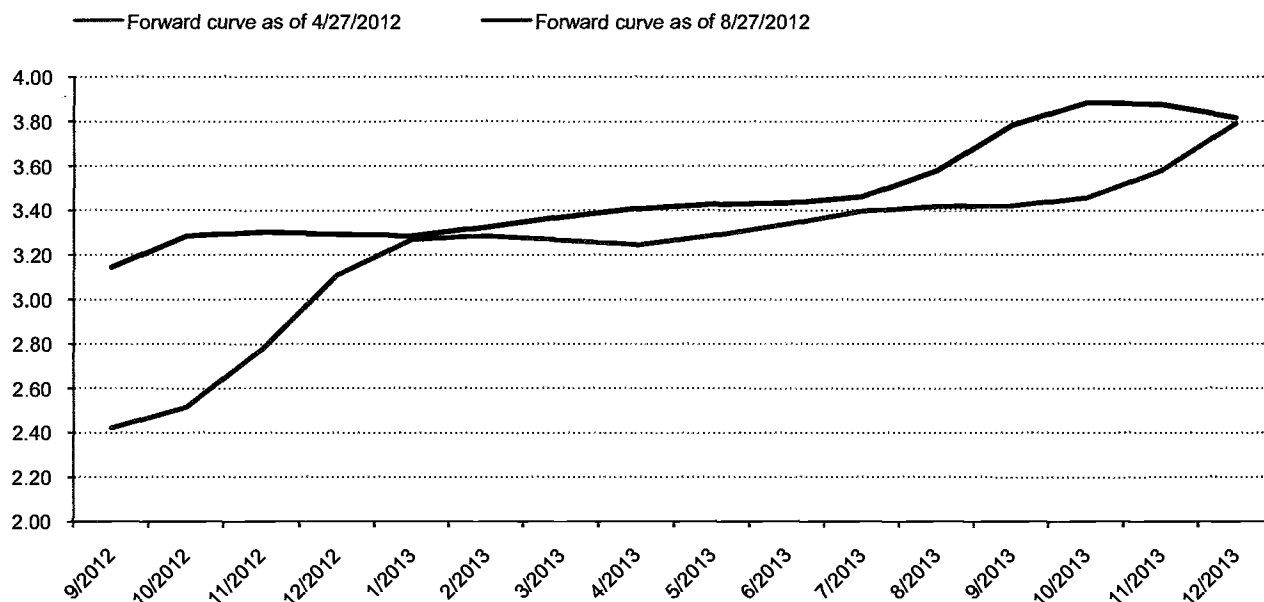
Coal-to-gas switching is particularly sensitive to natural gas market prices. Unlike deliveries to coal plants which are primarily done through long-term contracts and thus see less price volatility, natural gas is largely procured through spot purchases or contracts indexed to spot prices. This results in switching economics that can rapidly change with evolving natural gas market conditions and that exhibit the pronounced seasonality associated with natural gas markets.

Natural gas prices began to fall in 2011 after the summer heat subsided, a trend which strengthened in the winter and spring months of 2012 as unseasonably mild weather set in across much of the country. Prices at the Henry Hub broke a key support of \$2.00/MMBtu in early April dropping to as low as \$1.85/MMBtu. Sub-two-dollar natural gas prices were short lived, however, and began to rise through the early summer months peaking at \$3.21/MMBtu on August 1. Prices have come in below \$3/MMBtu since that time.



The outlook for natural gas prices has strengthened since SNL Energy's last analysis with the forward curve for September through December showing improvement, particularly for the September and October contracts. The chart below shows the NYMEX Henry Hub forward curve pulled as of April 27, 2012 compared to the forward curve as of the end of August. A \$.72/MMBtu strengthening in the forward contract for September can be seen with an even higher gap for October at \$.77/MMBtu.

Figure 2: NYMEX Henry Hub forward curve (\$/MMBtu)



Source: SNL Energy

The forward curve as of August 27 puts prices at \$3.14/MMBtu for September with prices hovering around \$3.30/MMBtu for the remaining months of 2012.

In the early summer months some analysts warned of a possible breach in natural gas storage and a resulting crash in prices. Many of these fears alleviated over the course of the summer as record-heat in many portions of the country and switching-driven demand have worked to push down storage levels.

Working gas storage levels for the lower 48 states as of August 31 were at 3,402 Bcf, 10.71% above the five-year average and roughly 12% over levels for the same period last year. Production shut-ins from Hurricane Isaac should work to slow storage builds for the first two weeks of September but builds are likely to accelerate thereafter as expected mild weather in September and October sets in across many portions of the country. The EIA expects working natural gas inventories at the end of October to reach 3,954 Bcf, setting a new record, according to the August Short Term Energy Outlook. The EIA recently announced new estimates for working natural gas storage capacity in the U.S. which put demonstrated capacity at 4,239 Bcf for 2012, 136 Bcf higher than the 2011 estimates. Based on these revised estimates, end-of-season inventories should come in below maximum capacity significantly reducing the likelihood of a storage breach and a resulting crash in prices.

Coal market environment

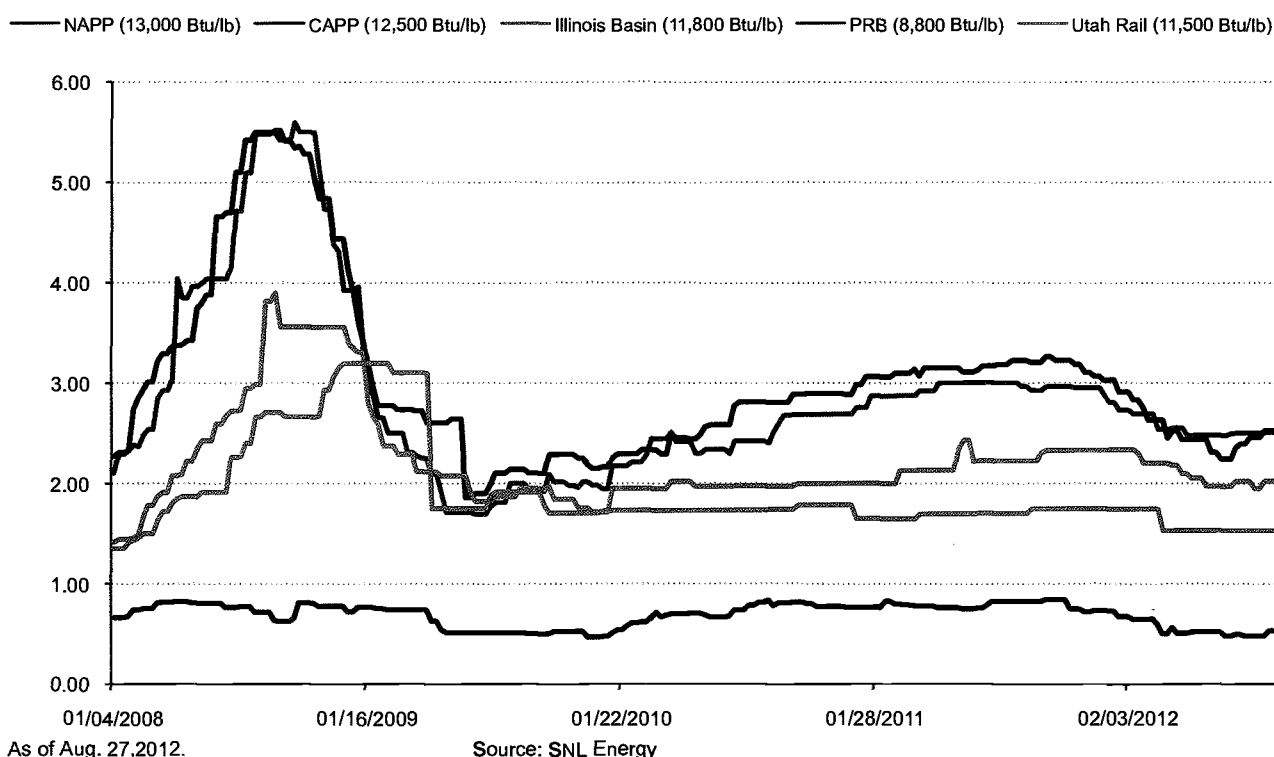
2012 has been a tumultuous year for coal producers with mild winter weather and record low natural gas prices working to drive down coal burn to levels not seen in many years. The EIA estimates that power sector coal consumption in 2012 will be at its lowest level in 20 years.

Coal producers responded to lower demand throughout the spring months with production cuts announced by many of the largest coal companies. As of September 1, 2012, year-to-date U.S. coal production totaled 682.5 million short tons, 5.4% below levels for the same period in 2011.

Coal market prices for most regions fell sharply during the late winter and early spring months but have seen some improvement over the summer as demand has been bolstered by hot weather and strong exports, as well as the price-supportive impacts of production cuts.

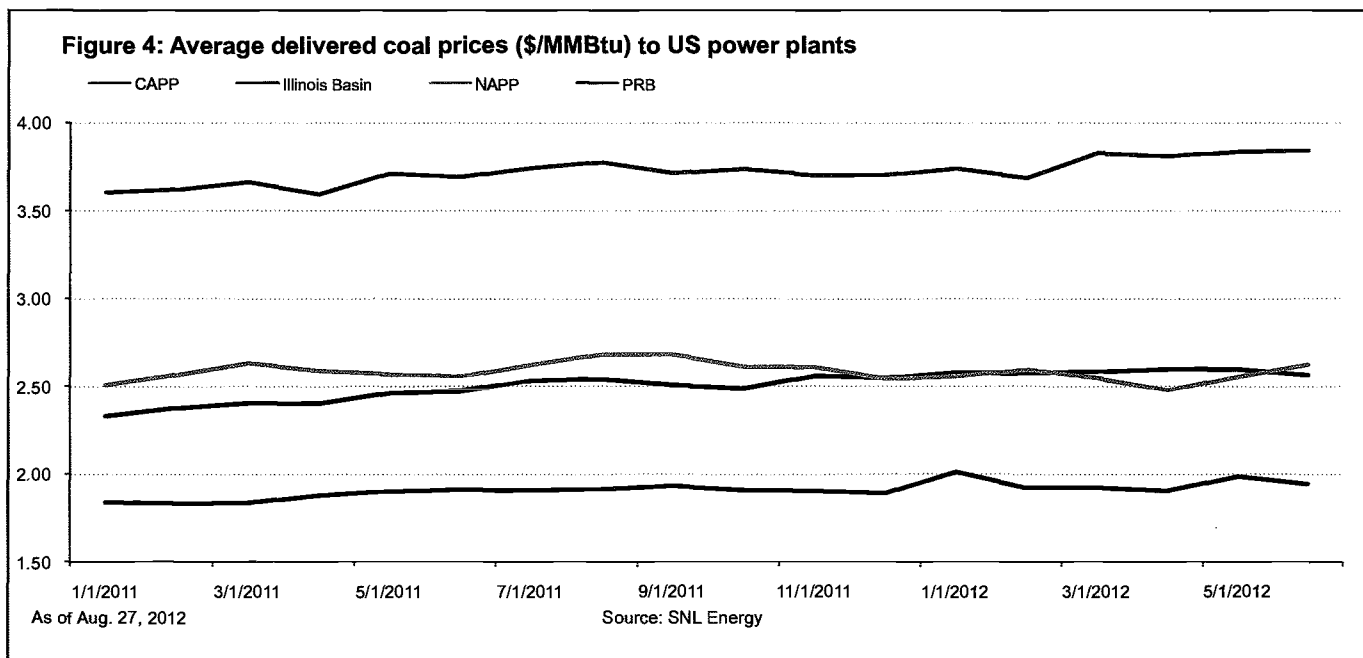
Physical market prompt-quarter prices for Central Appalachia 12,500-Btu coal have fallen nearly 20% off of 2011 levels to \$2.52/MMBtu as of August 31, 2012. Northern Appalachia 13,000-Btu coal prices have fallen 15% over the same time period reaching \$2.50/MMBtu as of August 31. Powder River Basin 8,800-Btu coal has seen the sharpest drop off of 2011 levels at 32% sitting at just \$.53/MMBtu at the end of August while prices for Illinois Basin Rail 11,800-Btu coal are down just over 8% from prior-year levels.

Figure 3: US physical market prompt quarter coal prices (\$/MMBtu)



Despite overall drops in coal market prices, coal prices as delivered to power plants have actually risen in 2012 compared to 2011 levels. Coal deliveries are fundamentally different from natural gas in that a significant portion of the delivered cost is comprised of transportation expenses. SNL Energy-estimated coal transportation cost data through May 2012 shows an 18% increase in average transport rates for the first 5 months of 2012 compared to 2011 average levels. Converted into \$/MMBtu, this translates into a \$.12/MMBtu increase in average transport rates. Over this same time period, the average free-on-board coal price associated with coal deliveries to power plants has dropped \$.116/MMBtu working to offset most of the increase in transport rates.

Looking forward, some analysts point towards a coming decline in rail rates, citing recent contract renegotiations as proof that the days of huge price gains are over. The current NYMEX forward curve for ultra-low-sulfur diesel puts the price at \$3.12 to \$3.18 per gallon for October through December 2012. These levels are significantly below prices of over \$3.50/gallon seen in the first half of 2012 and should take some pressure off of rail rates for the rest of the year.



Inventories at U.S. coal plants, which swelled to an estimated 203 million tons in May according to the EIA, fell over the summer months on relatively strong weather-driven coal burn. EIA data puts coal stocks in August at 188 million tons, roughly 4 million tons below the high recorded from 2003 to 2010. EIA projections have coal inventories rising to 198 million tons in November before dropping to 194 million tons in December, a record high.

Displacement trigger points

There has been significant discussion in the industry regarding the natural gas price points which might trigger economic displacement of coal plants in various regions. This has been especially true of regions that rely primarily on Illinois Basin and Powder River Basin coals as these regions have largely been on the margin at recent natural gas market prices.

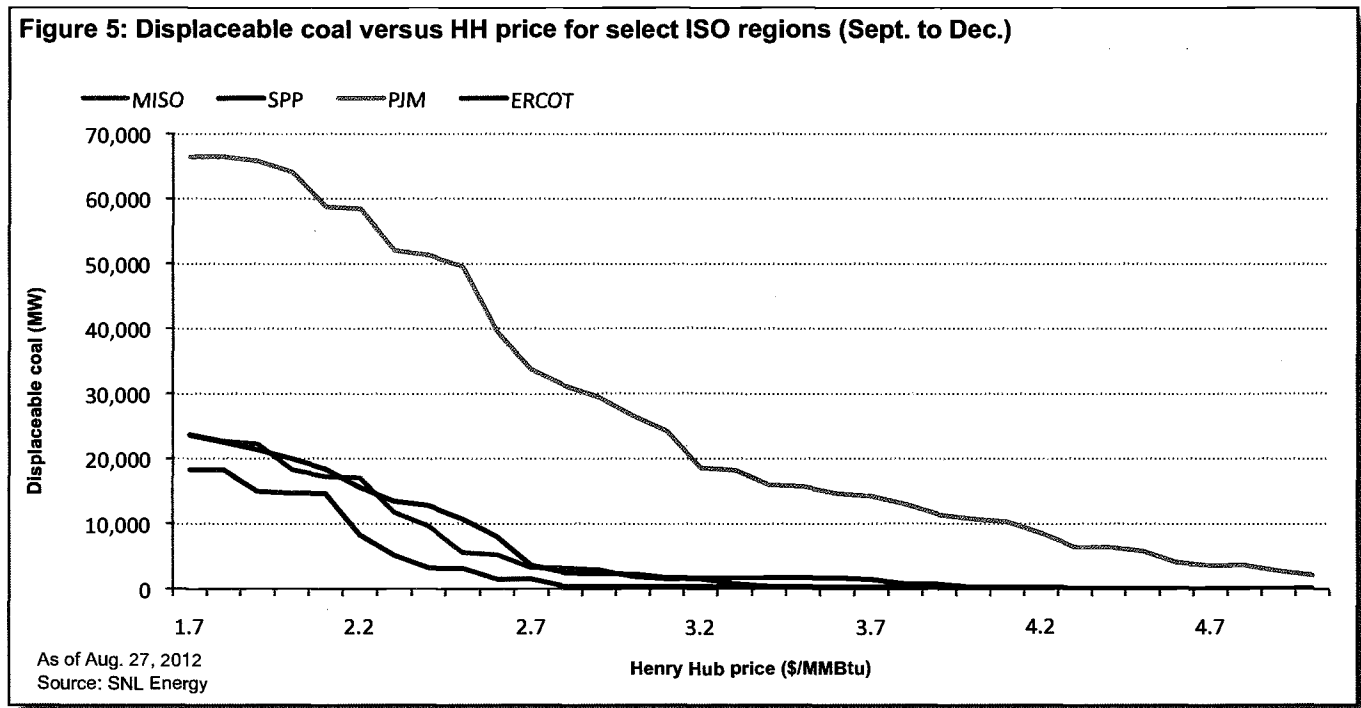
SNL Energy analyzed variable costs for the U.S. non-cogenerating coal fleet to compare to regional CCGT costs. For coal plants this includes the contracted cost of the coal commodity, coal transport rates, SO₂ and NO_x emissions costs, as well as other assumed variable components of non-fuel O&M. For CCGT plants, variable costs include the cost of natural gas as delivered to the plant, as well as the variable portion of non-fuel O&M.

For CCGT plants, average regional delivered natural gas spot prices were compared historically to the Henry Hub spot price for the September to December period to derive an average differential between the Henry Hub spot price and delivered natural gas costs for this period. This average differential was then used to estimate regional CCGT variable costs at various Henry Hub price points and then compared to regional coal variable costs to determine the amount of displaceable coal capacity at each price point.

The chart below shows displaceable coal capacity versus the Henry Hub spot price for some of the nation's coal-heavy ISO regions using a range of natural gas spot prices from \$1.70/MMBtu to \$5.00/MMBtu. Relationships shown are based on average differentials to natural gas plants for September through December.

Coal plants in PJM, which has been at the epicenter of coal to gas switching, has the most economically displaceable coal capacity within the natural gas price ranges shown. At the low-end natural gas price of \$1.70/MMBtu virtually

all of PJM's non-cogenerating coal capacity is out of the money. The chart also shows that at any price below \$2.50/MMBtu, more than 50,000 MW of coal capacity in the region is economically displaceable. Between \$2.50/MMBtu and \$3.20/MMBtu, displaceable capacity in the region falls off sharply with under 20,000 MW susceptible to switching at \$3.20/MMBtu. Based on the Henry Hub forward curve as of August 27, the September through



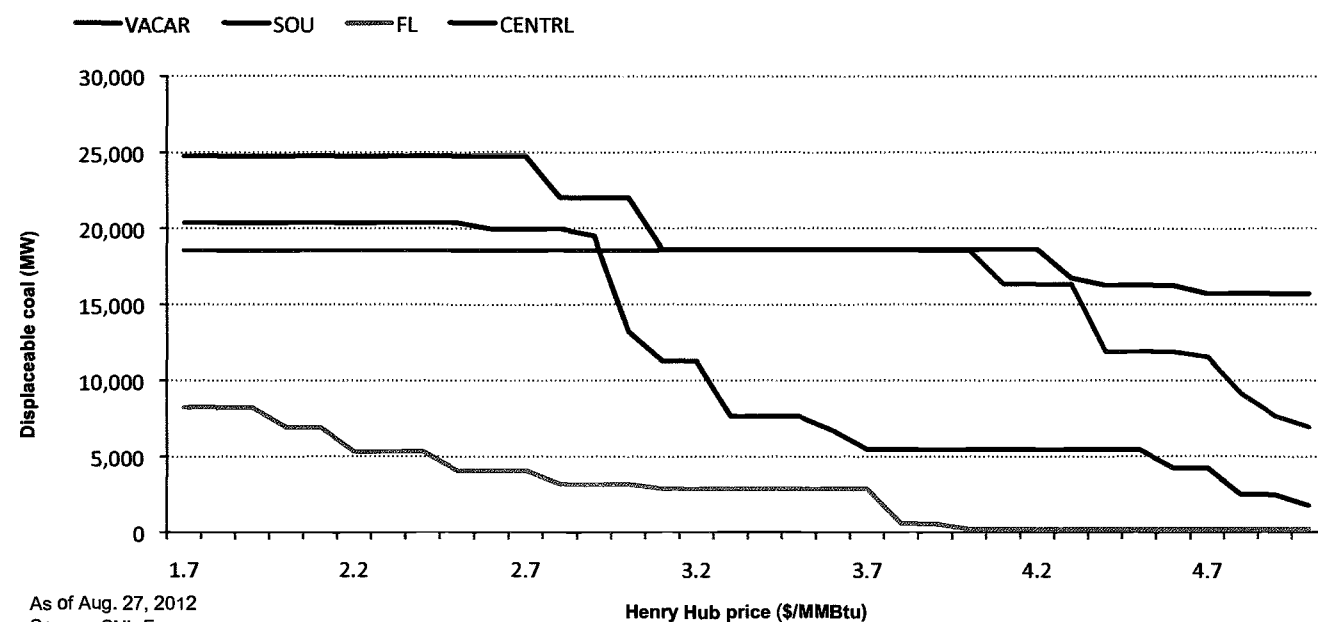
December strip averaged \$2.83/MMBtu, between the range where displaceable capacity in the region changes rapidly with a move in natural gas spot price. Within this range, reasonable drops in natural gas prices due to a milder than expected fall or large storage builds could substantially increase the amount of displaceable coal in the region.

Plants in MISO, SPP, and ERCOT, which all rely heavily on PRB coal, exhibit a similar pattern where displaceable coal capacity drops off significantly above \$2.70/MMBtu. Below \$2.70/MMBtu, displaceable capacity in each region begins to climb, and so these regions may be susceptible to some displacement with further drops in natural gas spot prices.

SNL Energy also examined some of the most coal-dependent NERC sub regions. Sub regions shown are based on legacy NERC sub region and only include the portions of each region not belonging to an ISO. Coal plants in the SOU sub region, which includes the service territories of Southern Company, remain largely economically displaceable within the ranges of natural gas prices studied though displaceable capacity drops off by roughly 6,000 MW between \$2.70/MMBtu and \$3.10/MMBtu.

Within the VACAR sub region, nearly 19,000 MW of coal capacity is economically displaceable at prices below \$4.00/MMBtu and will likely experience maximum possible displacement for the rest of 2012. The CENTRL region, home to TVA, has over 20,000 MW of displaceable coal capacity below \$2.90/MMBtu but this begins to drop off quickly at higher prices. Less than 5,000 MW of coal capacity in the FL sub region is subject to potential displacement within ranges of natural gas prices likely to be seen for the rest of the year.

Figure 6: Displaceable coal versus HH price for select sub regions (Sept. to Dec.)



Discussion of results and implications for natural gas

SNL Energy used coal and CCGT plant financial and operating information to identify potentially displaceable coal plants for September through December 2012. This information was then used in an hourly CEMS generation model to estimate maximum potential coal generation displacement compared to the same period in 2011. For a full discussion of methodology, please see the model methodology section.

SNL Energy considered three scenarios for displacement to reflect differing possible values for natural gas prices. In the baseline scenario natural gas prices were taken from the NYMEX forward curve for various natural gas hubs as of August 27, 2012. A scenario was also considered where natural gas prices remain consistent with this forward curve for the months of September and October, but then rise \$.60/MMBtu in November and December. This reflects a possible outcome where storage build through October comes in below expectations coupled with early winter weather beginning in November. Finally, SNL Energy considered the possibility of a \$.60 drop in natural gas prices from the Aug. 27 forward curve for November and December reflecting more aggressive storage builds during the summer build season coupled with mild early winter weather.

Overall results are shown below for the three scenarios considered. Total maximum coal displacement for September through December ranged from 39,011,522 MWh under the high natural gas price assumption to 56,559,119 MWh under the low natural gas price assumption. This translates into an overall maximum call on natural gas of 2.40 Bcf/d to 3.48 Bcf/d. The maximum call on natural gas under the baseline scenario was between the two extremes at 2.95 Bcf/d.

The chart below shows regional and monthly natural gas displacement under the baseline scenario. Nationwide, displacement would peak in October resulting in a maximum call on natural gas of 3.34 Bcf/d but then fall to 2.23 Bcf/d on average for December.

PJM would see the highest potential displacement between September and December under the baseline scenario resulting in an average 1.19 Bcf/d call on natural gas. PJM is followed by the SOU sub region which could see up to 0.48 Bcf/d of incremental natural gas demand from switching.

While it is widely known that much of the Eastern fleet is at a cost disadvantage compared to the average CCGT plant,

there has been a great deal of interest about the MISO and ERCOT regions which have typically been on the margin. Under the baseline case studied, displacement in ERCOT is minimal resulting in just a 0.04 Bcf/d call on natural gas while MISO is slightly higher at 0.14 Bcf/d on average. This potential expands in the low natural gas price case with ERCOT seeing an average maximum increase in natural gas demand of 0.25 Bcf/d with MISO slightly higher at 0.28 Bcf/d.

Figure 7: Displacement summary

	Coal generation displaced (MW)	Implied call on gas (Bcf/d)
High HH price	39,011,522	2.40
Low HH price	56,559,119	3.48
Baseline	47,988,859	2.95

As of Aug. 27,2012

Source: SNL Energy

Figure 8: Natural gas displacement (Bcf/d) summary under baseline scenario

Region	Sep	Oct	Nov	Dec	Sep-Dec average
NERC sub region					
AZNMSN	0.06	0.05	0.05	0.00	0.04
CENTRL	0.24	0.17	0.20	0.06	0.17
DELTA	0.09	0.07	0.00	0.00	0.04
FL	0.11	0.19	0.22	0.17	0.17
RMP	0.01	0.01	0.01	0.01	0.01
SOU	0.42	0.51	0.42	0.58	0.48
VACAR	0.15	0.24	0.27	0.20	0.21
Within ISO					
CAISO	0.19	0.26	0.28	0.15	0.22
ERCOT	0.04	0.06	0.07	0.00	0.04
ISO-NE	0.02	0.05	0.01	0.02	0.03
MISO	0.18	0.18	0.10	0.11	0.14
NYISO	0.01	0.00	0.00	0.00	0.00
PJM	1.16	1.40	1.48	0.74	1.19
SPP	0.28	0.15	0.18	0.19	0.20
Total	2.96	3.34	3.28	2.23	2.95

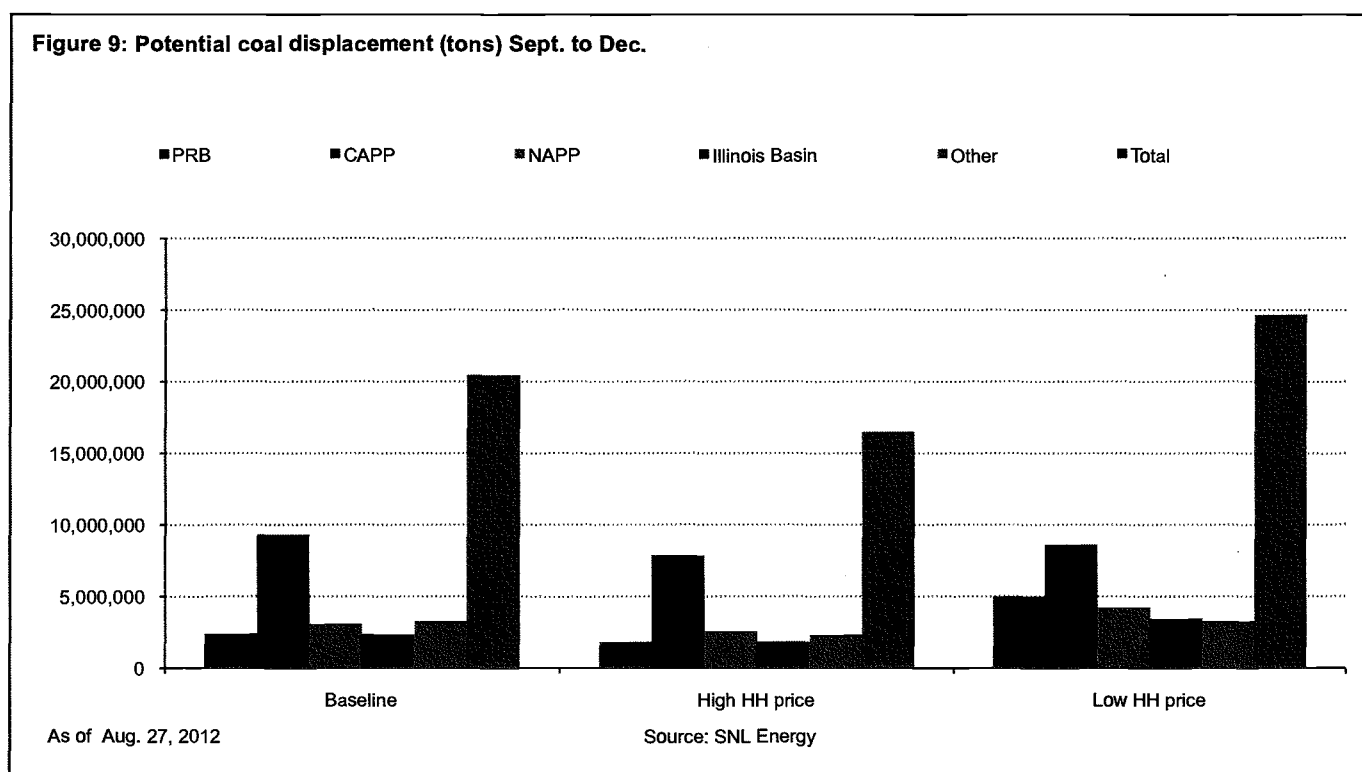
As of Aug. 27,2012

Source: SNL Energy

Discussion of results and implications for coal

Generation displacement derived from the model was used to estimate the implied total drop in coal tonnage. Total displaced generation was converted to total MMBtus displaced using the average monthly heat rate of displaceable plants. Figures were then calculated for the estimated fraction of displaceable MMBtus coming specifically from major coal regions which was then used to derive individual tonnage amounts.

Total calculated coal displacement ranged from 16.5 million tons under the high natural gas price outcome to 24.7 million tons under the low natural gas price scenario. The baseline case was again between these two extremes with a total displacement of 20.5 million tons.



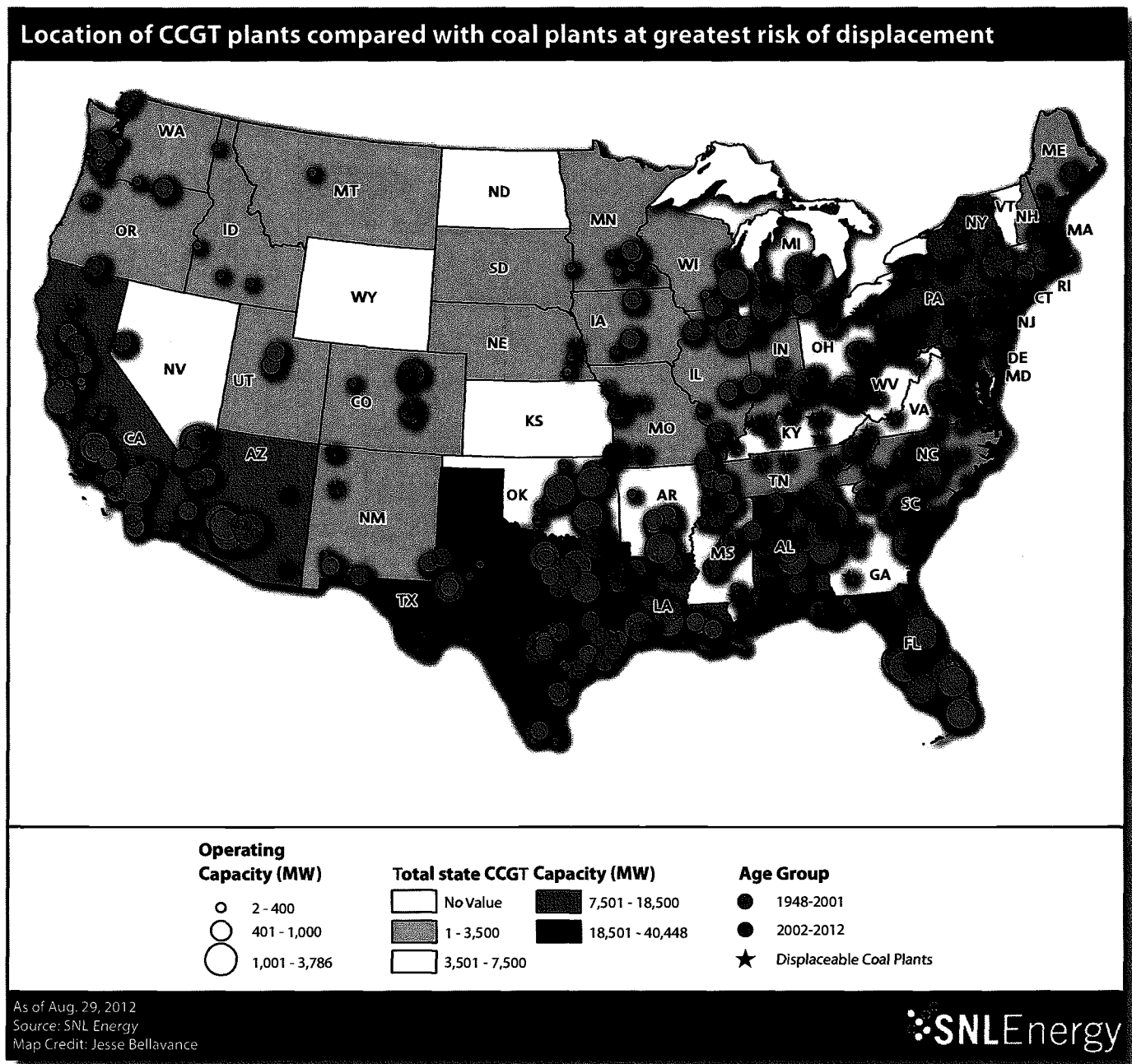
Under both the baseline and high natural gas price cases, the distribution of coal volumes displaced is similar with CAPP coal comprising the lion share of volumes at around 47%. NAPP takes a roughly 15% share of these volumes under these two cases, with Illinois Basin coal making up 15% and PRB comprising a roughly 11% share. Under the low natural gas price scenario PRB volumes displaced grow substantially and make up 20% of total displacement, while NAPP and Illinois Basin coal rise to 17% and 14% of displaced volumes respectively with CAPP coal actually falling to 35%.

Conclusions and key considerations

SNL Energy's analysis did not consider several factors which may influence potential coal displacement including the state of coal contracts and inventories, locational differences between competing natural gas capacity and transmission bottlenecks. The model also does not incorporate costs related to increased coal plant cycling as well as operational constraints that may prevent instantaneous switching. SNL Energy's estimates, therefore, represent a maximum level of displacement based on plant economics and may overstate potential due to restrictions limiting plant switching.

A large amount of displaceable capacity continues to be found in the PJM region particularly in Ohio, western Pennsylvania and West Virginia where there is limited CCGT capacity. Coal inventories particularly in the Southeast and PJM may work to prevent full levels of switching in some cases as generators may be forced to burn some coal to take minimum tonnage requirements. Overall, coal inventories nationwide have seen a decline off of the high spring levels due to hot summer weather in many portions of the country and successful contract deferments. These easing inventories may create headroom for further switching potential.

Storage volumes will need to be watched closely through the rest of the build season as many estimates put the end-of-season inventory below, but close to maximum working storage capacity. Weather will be a key consideration but may be difficult to predict in the transition from the previous La Niña pattern to the rising El Niño.



Based on the current natural gas forward curve switching remains largely an Eastern phenomenon with total maximum potential estimated at 2.95 Bcf/d. This could expand to 3.48 Bcf/d with a roughly \$.60/MMBtu drop in natural gas prices for November and December and open up the potential for increased displacement of PRB and Illinois Basin coal volumes. Conversely, a \$.60/MMBtu rise in November and December natural gas prices could result in a drop in incremental natural gas demand to 2.40 Bcf/d leaving Western and Midwestern coals largely in the clear.

Model methodology

SNL Energy used plant operational and fuel delivery data to identify a list of economically displaceable coal plants, along with maximum potential displacement from these plants in the last four months of 2012. For each of these plants a \$/MMBtu natural gas floor was calculated for each coal type burned by the plant using the plant's variable non-fuel O&M, delivered coal costs, as well as average costs for SO₂ and NO_x allowances as previously described. These costs were then adjusted based on the plant's individual heat rate versus average heat rates for CCGT plants in the region.

Each coal plant's natural gas floor calculation was compared to a marginal cost of natural gas calculation for CCGT plants in the region in which the plant is located. For each of these regions, variable CCGT costs were calculated by taking average variable non-fuel O&M for plants in the region and adding it to an estimate of average delivered natural gas costs for each forward month of 2012 from September through December. Each region was assigned the most representative natural gas hub with NYMEX forward data available. Estimated forward delivered costs for each month were calculated by taking the representative NYMEX forward curve for each of the monthly contracts in 2012 and adding it to the historical average monthly difference between spot prices at that hub and delivered natural gas costs to CCGT plants in the region.

For each coal plant considered, the adjusted variable cost for each coal type was compared to regional CCGT costs for each of the forward months considered. The plant was identified as potentially displaceable in a particular month if the natural gas-equivalent marginal cost of burning any coal type was higher than regional CCGT costs for that month. A figure for displaceable capacity for each month was also calculated for the plant by adjusting total operating capacity by the percentage of coal found to be displaceable at the plant in that month. The percentage of each coal type utilized by the plant was determined by using data on coal deliveries to the plant as a proxy for fuel burn.

As an example, consider a 100 MW coal plant which burns 60% CAPP and 40% Illinois basin coal. If regional CCGT costs in April were found to be \$3.50/MMBtu while the efficiency-adjusted cost of burning CAPP coal was \$4.25/MMBtu and the comparable cost for Illinois Basin coal was found to be \$3.00/MMBtu, the plant would be identified as displaceable in April with an adjusted displaceable capacity of 60 MW.

SNL Energy considered three scenarios for displacement to reflect differing possible values for natural gas prices. In the baseline scenario natural gas prices were taken from the NYMEX forward curve for various gas hubs as of August 27, 2012. A scenario was also considered where natural gas prices remain consistent with this forward curve for the months of September and October, but then rise roughly \$.60/MMBtu in November and December. This reflects a possible outcome where storage build through October comes in below expectations coupled with early winter weather beginning in November. Finally, SNL Energy considered the possibility of a roughly \$.60 drop in natural gas prices from the Aug. 27 forward curve for November and December reflecting more aggressive storage builds during the summer build season coupled with mild early winter weather.

Once potentially displaceable plants were identified, SNL Energy calculated figures for maximum coal generation displacement for each scenario using 2011 as a base year. Displaceable coal plants were organized by region and

gross coal generation was aggregated for each region and for every hour of 2011. Gross generation figures were scaled down to reflect net figures using the ratio between gross and net generation for coal plants in each region.

Hourly CCGT gross generation data in 2011 was also aggregated by region using EPA CEMS data collected by SNL Energy. Gross generation figures were also scaled down to bring them to net figures. Calculated net generation figures were then scaled upward to account for the ST portion of the plant which is not reported in the CEMS data. A ratio for net generation in 2011 coming from the ST portion of the plant was calculated for each region and used to scale up the CEMS CT generation figures. For most regions, the ST portion of the plant was found to make up roughly one third of total plant generation.

Hourly CCGT generation was compared to figures for hourly maximum CCGT generating capacity in the region to calculate the amount of excess CCGT generation available in each hour. Maximum CCGT generation in a single hour was set to 85% of the full operating capacity of CCGT plants in the region as has been used in a number of other coal to gas switching research pieces.

Regional switching potential for each hour was calculated by comparing excess CCGT generation to the generation of displaceable coal plants in that region. If ample excess CCGT generation was available to displace all coal generation in a particular hour, then the amount of displacement was set at the level of coal generation otherwise it was calculated as the amount of excess CCGT generation. 



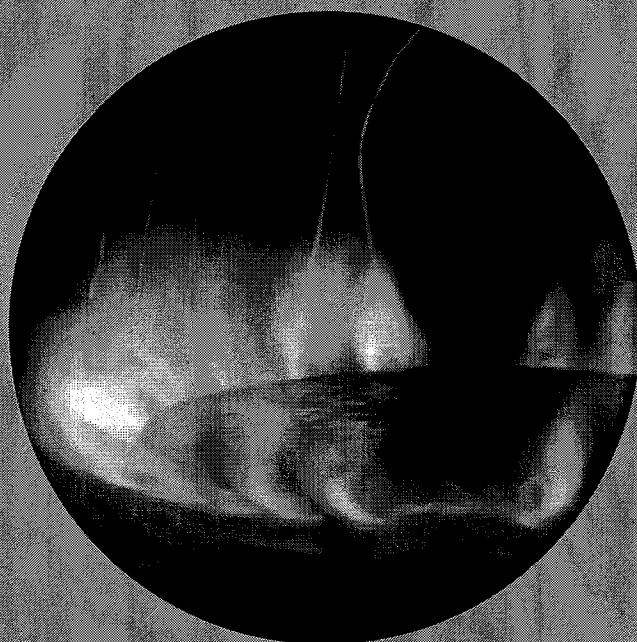
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support@snl.com

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33

Coal Capacity at Risk for Retirement in PJM:

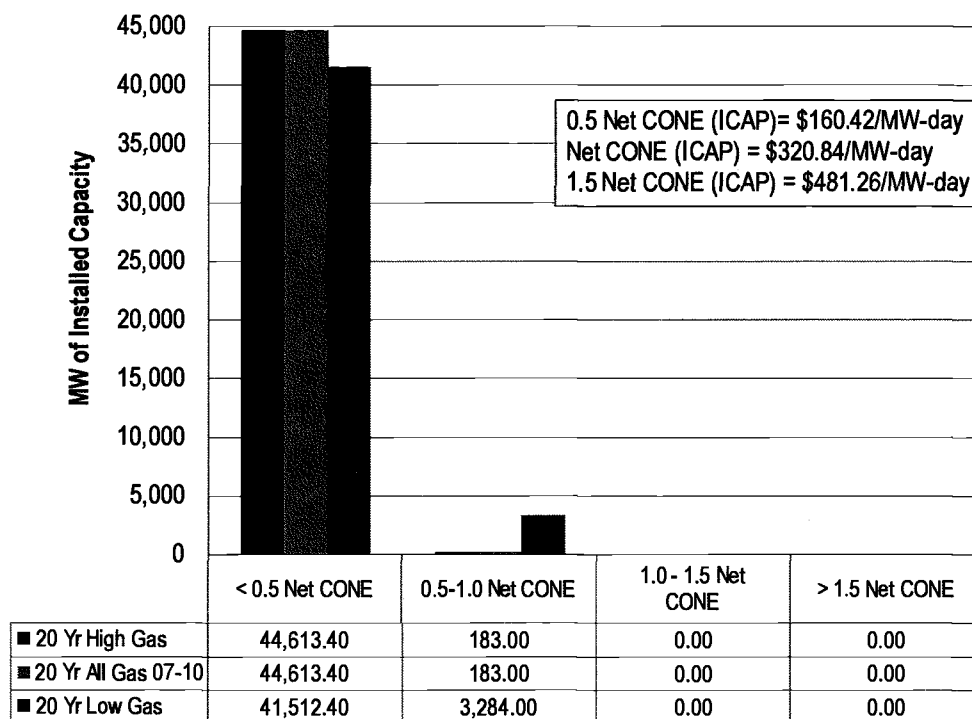
Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants

8.26.2011

PJM Interconnection



Figure 12: MW of Installed Capacity with Needed Revenues Benchmarked against Net CONE in Rest of RTO



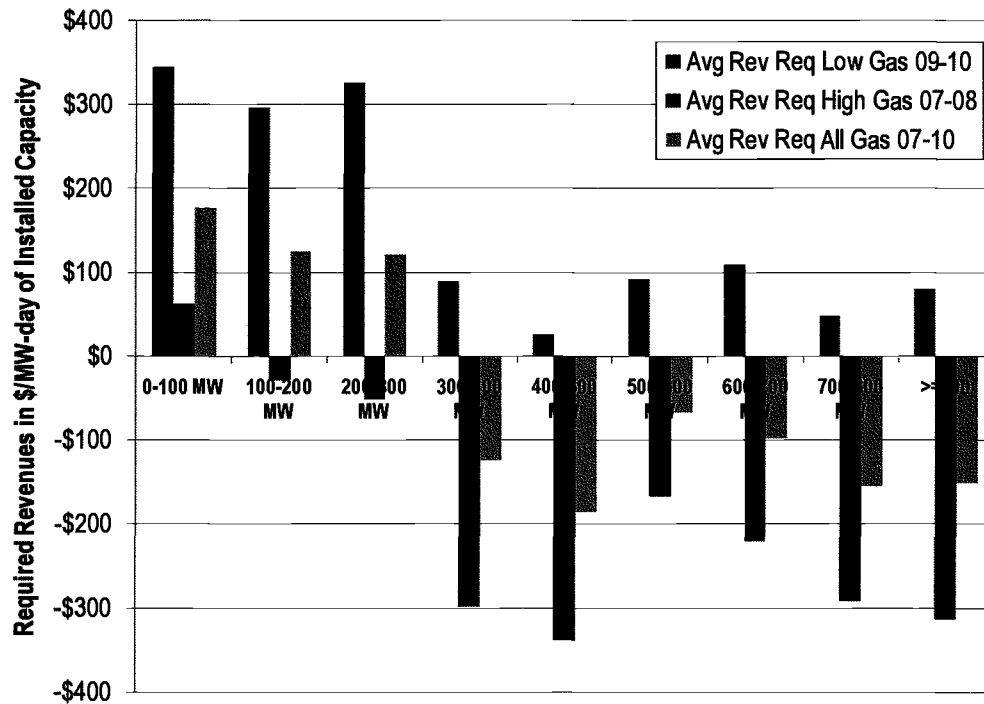
Coal Capacity at Risk Due to the CSAPR and NESHAP Rules

If the owner of a coal unit makes the decision to make investments in pollution control retrofits, it would be reasonable to expect that the unit owner is making a long-term investment in that unit and that the payback period on the retrofit investment would be similar to investing in a new natural gas combined cycle plant or simple cycle combustion turbine. Under the PJM Tariff and market rules this period is 20 years for the new entry reference resource. In thinking about the pollution control retrofit along the same lines as investment in new entry natural gas, it allows for the benchmarking of the costs with retrofits against the Net CONE of the reference resource as discussed above.

In considering future economic conditions, such as gas prices and demand, it is reasonable to use a historic scenario that corresponds as closely as possible to forecasts of future gas prices and energy demand. The required revenues under this scenario would enable retrofit/retire decisions based on forecasts currently in place.

Figure 13 shows the necessary revenues to continue forward for coal units by size and natural gas price/demand scenario. Compared to the results in Figure 10 without CSAPR and NESHAP, the required revenues to continue operating are higher, especially for smaller units. For units below 300 MW in size, the needed revenues are at least \$300/MW-day of installed capacity in the high gas price/low demand case, and for all units on average the needed revenues to go forward are greater than zero. Even in the other gas price cases, the economics of smaller units on average have been significantly eroded. This result demonstrates that older, smaller units are less efficient, run less often and will not have the same kind of net revenues to cover retrofit costs, and will also not be able to take advantage of any economies of scale in retrofit installations. For larger units, more than 300 MW in size, the revenues needed to continue operating are generally less than \$100/MW-day on average.

Figure 13: Necessary Revenues to Continue Forward by Unit Size and Case



Figures 14 and 15 present the MW quantities of capacity, benchmarked against different levels of Net CONE in MAAC and the rest of RTO. Figure 11 shows that there is about 3,200 MW of installed capacity that requires more than Net CONE to go forward in MAAC under the low gas price/low demand scenario. A total of almost 1,500 MW require more than 1.5 Net CONE, which is the maximum price that could prevail in MAAC if it were a separate LDA. In the rest of RTO, as shown in Figure 15, there is more than 7,800 MW of capacity requiring more than the Net CONE in the low gas price/low demand case. In total across the RTO, there is just over 11,000 MW of capacity that would require more than the Net CONE to continue forward in the low gas price/low demand case. The focus is on the low gas price/low demand case as forecasts of future gas prices and demand are on a much lower trajectory than was otherwise the case just a few years before, and closely match up with gas prices that prevailed in 2009-2010.

Figures 14 and 15 also show capacity revenue needs under the other higher gas price/higher demand cases. If gas prices and demand had remained at 2007-2008 levels, there is slightly less than 1,500 MW of installed capacity that would require more than Net CONE to continue operating. In the case that blends the economic conditions from 2007-2010, this figure would be around 4,300 MW.

Given the baseline considering needed revenues to go forward in the absence of CSAPR and NESHAP, it is clear that these rules are driving the need for increasing revenues to incent coal capacity to continue operating. And the effects of these rules are exacerbated by the low gas price/low demand environment that is forecast to continue.

Figures 14 and 15 also show that across the entire PJM footprint, there another approximately 14,000 MW of coal-fired capacity in the low gas price/low demand case that would require between 0.5 Net CONE and Net CONE to continue forward. Coal capacity in this area is at some risk for retirement, but it would be difficult to precisely estimate how much of

this capacity would retrofit or retire. As explained above, the retrofit/retirement decision will depend upon factors that cannot be observed by PJM, such as unit specific conditions not immediately available to PJM, and owner expectations about the future economic and policy conditions.

Figure 14: MW of Installed capacity in the MAAC Region by Revenue Needs Relative to Net CONE

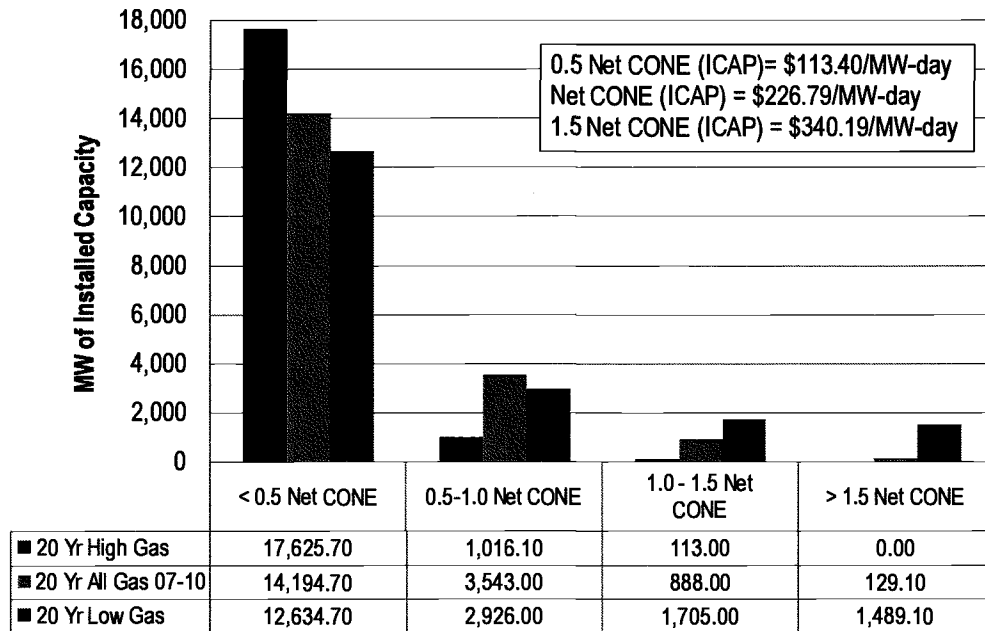
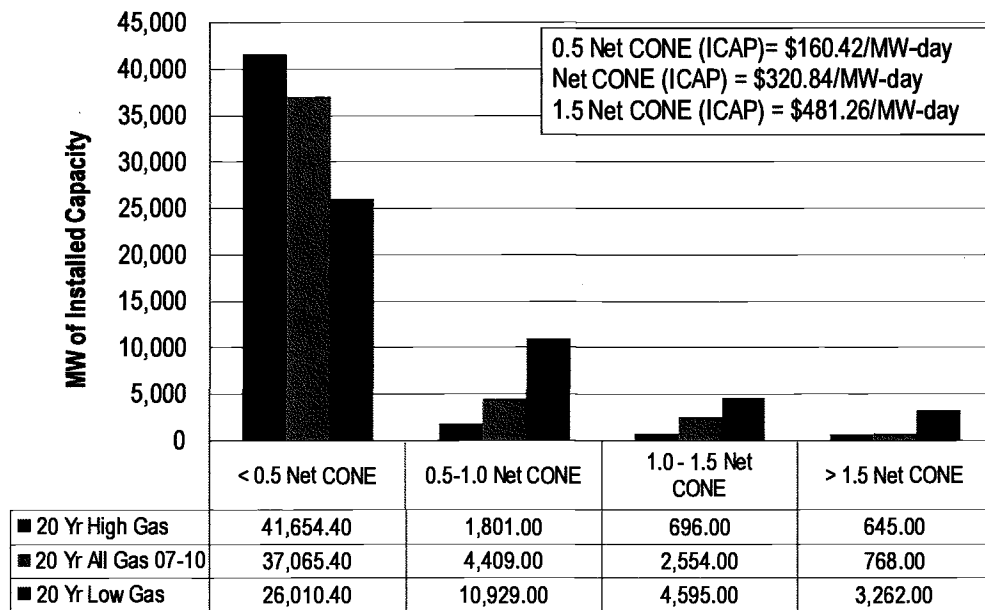


Figure 15: MW of Installed Capacity in the rest of RTO by Revenue Need Relative to Net CONE



34

**No. 11-1302 and consolidated cases
(COMPLEX)**

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

**EME Homer City Generation, L.P. *et al.*,
Petitioners,**

v.

**U.S. Environmental Protection Agency *et al.*,
Respondents.**

On Petition for Review of Final Rule Promulgated by the
United States Environmental Protection Agency

**PETITION FOR REHEARING *EN BANC* BY THE STATES OF NORTH
CAROLINA, CONNECTICUT, DELAWARE, ILLINOIS, MARYLAND,
MASSACHUSETTS, NEW YORK, RHODE ISLAND AND VERMONT,
THE CITIES OF BALTIMORE, BRIDGEPORT, CHICAGO, NEW YORK
AND PHILADELPHIA, AND THE DISTRICT OF COLUMBIA**

ROY COOPER

Attorney General of North Carolina

James C. Gulick

Senior Deputy Attorney General

J. Allen Jernigan

Special Deputy Attorney General

Marc Bernstein

Special Deputy Attorney General

North Carolina Department of Justice

P.O. Box 629

Raleigh, North Carolina 27602-0629

(919) 716-6600

Counsel for the State of North Carolina

(Additional counsel listed at signature lines.)

**ORAL ARGUMENT HELD APRIL 13, 2012
DECISION ISSUED AUGUST 21, 2012**

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

No. 11-1302 and consolidated cases (Complex)

**EME HOMER CITY GENERATION, L.P., et al.,
Petitioners,**

v.

**UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY, et al.,**

Respondents.

**ON PETITIONS FOR REVIEW OF A FINAL RULE PROMULGATED BY THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

PETITION FOR REHEARING EN BANC

**IGNACIA S. MORENO
Assistant Attorney General
NORMAN L. RAVE, JR.
JESSICA O'DONNELL
JON M. LIPSHULTZ
Environmental Defense Section
Environment and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, DC 20044
(202) 514-2219**

OF COUNSEL

**SONJA RODMAN
KAYTRUE TING
RAGAN TATE
STEPHANIE HOGAN
United States Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460**

DATED: October 5, 2012

35



U.S. Energy Information
Administration

Coal

Coal News and Markets

Release Date: November 13, 2012 | Next Release Date: November 19, 2012

"Coal News and Markets Report" summarizes spot coal prices by coal commodity regions (i.e., Central Appalachia (CAP), Northern Appalachia (NAP), Illinois Basin (ILB), Powder River Basin (PRB), and Uinta Basin (UIB)) in the United States. The report includes data on average weekly coal commodity spot prices, total monthly coal production, eastern monthly coal production, and average cost of metallurgical coal at coke plants and export docks. The historical data for coal commodity spot market prices are proprietary and not available for public release.

Average weekly coal commodity spot prices (dollars per short ton)

Week Ended	Central Appalachia 12,500 Btu, 1.2 SO2	Northern Appalachia 13,000 Btu, <3.0 SO2	Illinois Basin 11,800 Btu, 5.0 SO2	Powder River Basin 8,800 Btu, 0.8 SO2	Uinta Basin 11,700 Btu, 0.8 SO2
12-October-12	\$65.95	\$64.25	\$47.90	\$10.25	\$35.75
19-October-12	\$65.95	\$64.25	\$47.90	\$10.25	\$35.75
26-October-12	\$65.95	\$64.25	\$47.90	\$10.25	\$35.75
02-November-12	\$65.95	\$64.50	\$47.90	\$10.35	\$35.75
09-November-12	\$65.95	\$64.50	\$47.90	\$10.35	\$35.75

Source: With permission, SNL Energy

Note: Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the 2nd quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter. The historical data file of spot prices is proprietary and cannot be released by EIA; see SNL Energy.

36

ALPHA NATURAL RESOURCES, INC.

FORM 8-K (Current report filing)

Filed 06/28/10 for the Period Ending 06/28/10

Address	ONE ALPHA PLACE P.O. BOX 2345 ABINGDON, VA 24212
Telephone	276-619-4410
CIK	0001301063
SIC Code	1221 - Bituminous Coal and Lignite Surface Mining
Industry	Coal
Sector	Energy
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): June 28, 2010

ALPHA NATURAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation)

001-32331
(Commission File Number)

42-1638663
(I.R.S. Employer
Identification No.)

One Alpha Place, P.O. Box 2345,
Abingdon, VA 24212
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(276) 619-4410**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
 - ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
 - ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
 - ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))
-

RUNNING RIGHT



**Outlook for the Powder River Basin
June 28, 2010**

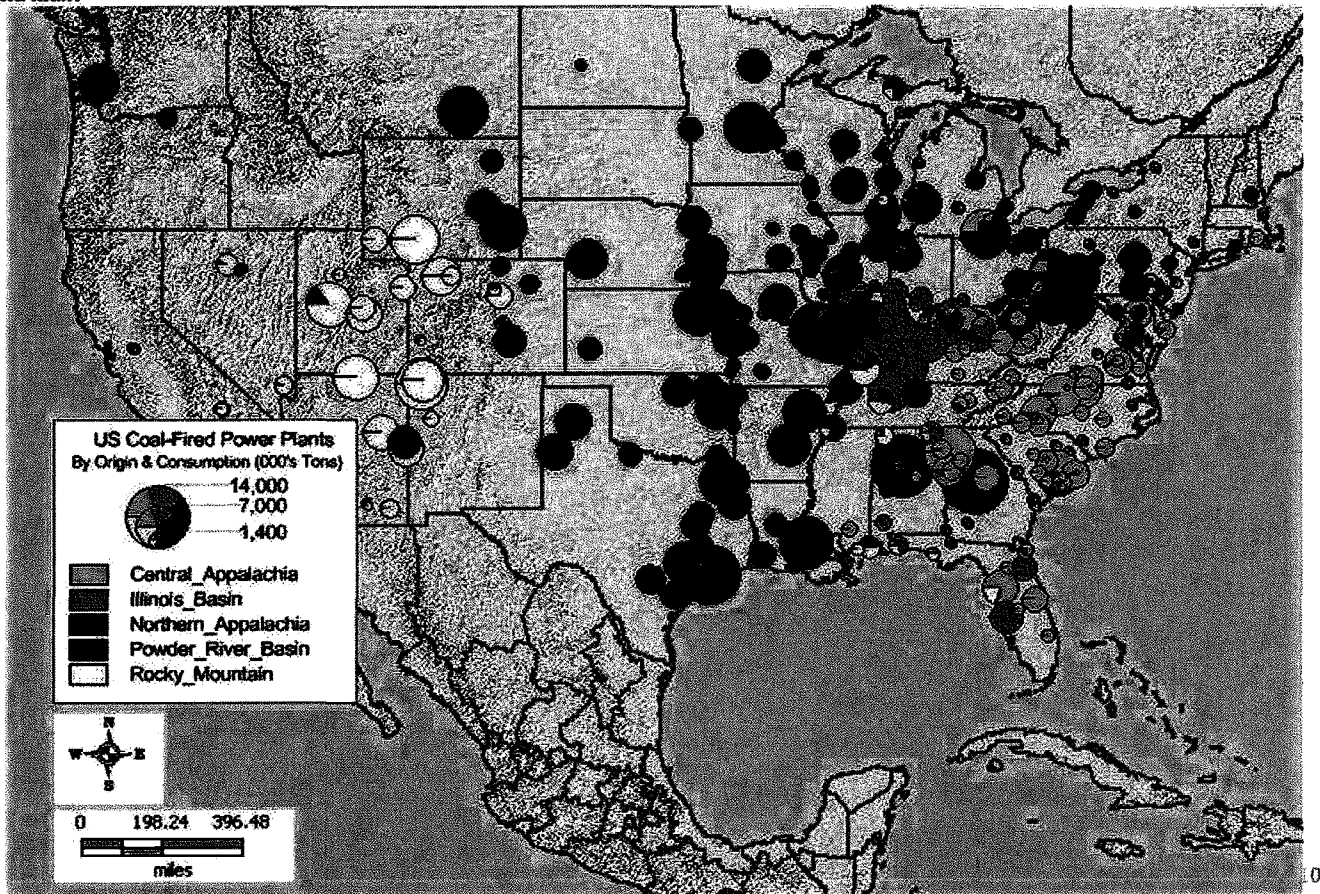
Rocky Mountain Coal Mining Institute Conference





RUNNING RIGHT

U.S. Coal-Fired Power Plants by Coal Origin



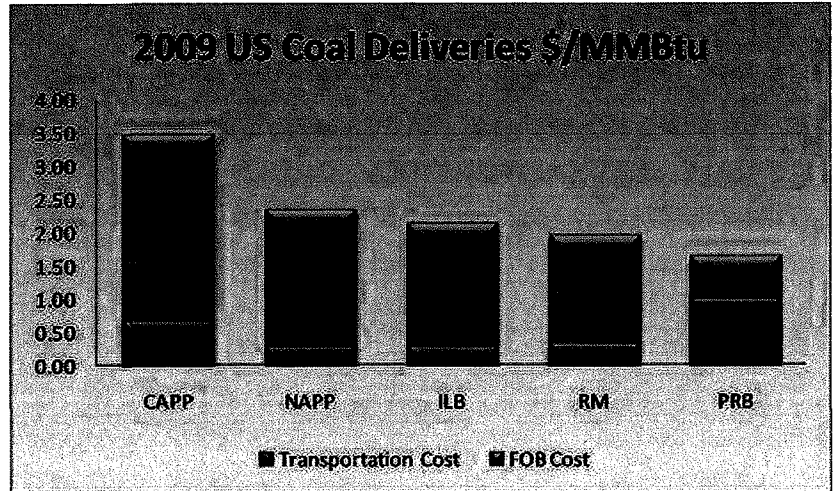
Source: Velocity Suite



2009 Delivered Coal Prices by Basin

RUNNING RIGHT

- Unlike the other basins, transportation costs dwarf FOB costs in the PRB.
- PRB is a very competitive basin provided that rail rates remain reasonable.
- Average transportation cost in PRB is \$1/MMBtu. For other basins, the average transportation cost is \$0.47/MMBtu.
- Average coal price in PRB is \$0.65/MMBtu compared to \$2.19/MMBtu in other basins.



37

Annual Energy Outlook 2012

With Projections to 2035

June 2012

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

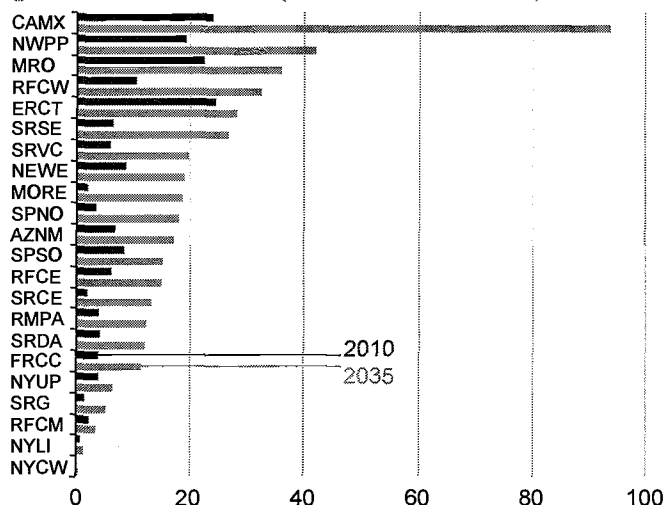
This publication is on the WEB at:

www.eia.gov/forecasts/aeo

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

State renewable portfolio standards increase renewable electricity generation

Figure 102. Regional growth in nonhydropower renewable electricity generation, including end-use generation, 2010-2035 (billion kilowatthours)



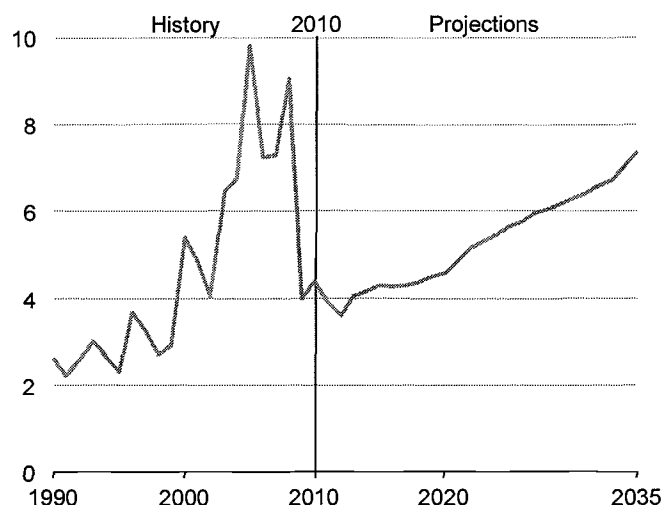
Regional growth in renewable electricity generation is based largely on two factors: availability of renewable energy resources and the existence of State RPS programs that require the use of renewable generation. After a period of robust RPS enactments in several States, the past few years have been relatively quiet in terms of State program expansions, primarily due to the subdued economic climate.

The highest level of nonhydroelectric renewable generation in 2035, 93.9 billion kilowatthours, occurs in the WECC California (CAMX) region (Figure 102), whose area approximates the California State boundaries. (For a map of the electricity regions presented, see Appendix F.) The three largest contributors to the total are wind, solar, and geothermal generation. The region encompassing the Pacific Northwest has more overall renewable generation, the vast majority of which comes from hydroelectric sources.

Although the Western and Southwestern States have the most projected solar installations, State RPS programs heavily influence the growth of solar capacity in the eastern States, where both the Reliability First Corporation/East (RFCE) and the Reliability First Corporation/West (RFCW) regions have large amounts of end-use solar generation, with 1.7 billion kilowatthours and 1.9 billion kilowatthours, respectively. The two regions are not known for a strong solar resource base, and the installations are in response to the ITC as well as solar requirements embedded in State RPS programs. Most biomass capacity—confined largely to the end-use sectors—is built at the sites of cellulosic ethanol plants, many of which are in the Southeast.

Natural gas prices are expected to rise with the marginal cost of production

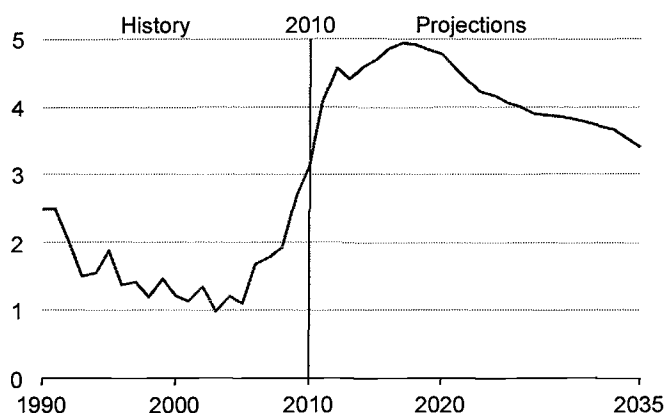
Figure 103. Annual average Henry Hub spot natural gas prices, 1990-2035 (2010 dollars per million Btu)



U.S. natural gas prices are determined largely by supply and demand conditions in North American markets. At current (2012) price levels, natural gas prices are below average replacement cost. However, over time natural gas prices rise with the cost of developing incremental production capacity (Figure 103). After 2017, natural gas prices rise in the AEO2012 Reference case more rapidly than crude oil prices, but oil prices remain at least three times higher than natural gas prices through the end of the projection (Figure 104).

As of January 1, 2010, total proved and unproved natural gas resources are estimated at 2,203 trillion cubic feet. Development costs for natural gas wells are expected to grow slowly. Henry Hub spot prices for natural gas rise by 2.1 percent per year from 2010 through 2035 in the Reference case, to an annual average of \$7.37 per million Btu (2010 dollars) in 2035.

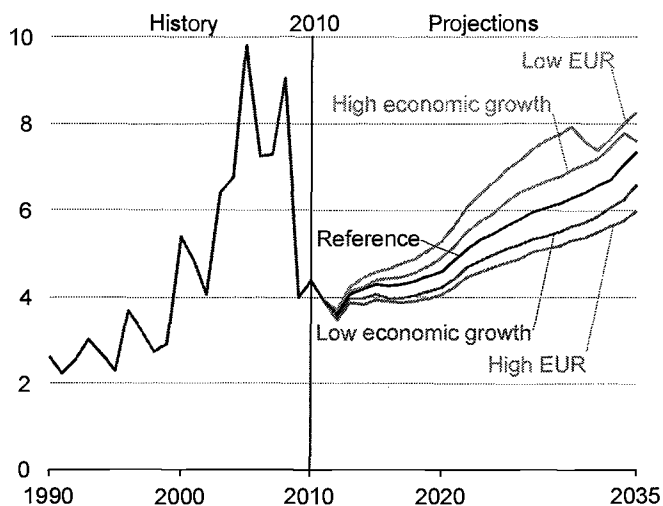
Figure 104. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on energy equivalent basis, 1990-2035



Natural gas production

Natural gas prices vary with economic growth and shale gas well recovery rates

Figure 105. Annual average Henry Hub spot natural gas prices in five cases, 1990-2035 (2010 dollars per million Btu)



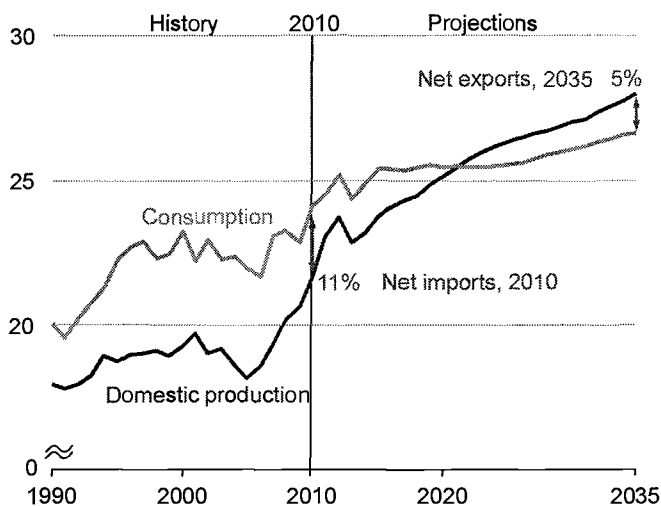
The rate at which natural gas prices change in the future can vary, depending on a number of factors. Two important factors are the future rate of macroeconomic growth and the expected cumulative production of shale gas wells over their lifetimes—the estimated ultimate recovery (EUR) per well. Alternative cases with different assumptions for these factors are shown in Figure 105.

Higher rates of economic growth lead to increased consumption of natural gas, causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new incremental natural gas production. Conversely, lower rates of economic growth lead to lower levels of natural gas consumption and, ultimately, a slower increase in the cost of developing new production.

In the High and Low EUR cases, the EUR per shale gas well is increased and decreased by 50 percent, respectively. Future shale gas well recovery rates are an important determinant of future prices. Changes in well recovery rates affect the long-run marginal cost of shale gas production, which in turn affects both natural gas prices and the volumes of new shale gas production developed (further analysis and discussion are included in the “Issues in focus” section of this report). In the Low EUR case, an Alaska gas pipeline starts operating in 2031, accompanied by a dip in natural gas prices. A recent proposal to build a natural gas pipeline along the route of the Alyeska oil pipeline with an LNG export facility could speed up construction. In the High Economic Growth case, the pipeline begins operation in 2035, with a similar effect on prices.

With rising domestic production, the United States become a net exporter of natural gas

Figure 106. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



The United States consumed more natural gas than it produced in 2010, importing 2.6 trillion cubic feet from other countries. In the AEO2012 Reference case, domestic natural gas production grows more quickly than consumption. As a result, the United States becomes a net exporter of natural gas by around 2022, and in 2035 net exports of natural gas from the United States total about 1.4 trillion cubic feet (Figure 106).

U.S. natural gas consumption grows at a rate of 0.4 percent per year from 2010 to 2035 in the Reference case, or by a total of 2.5 trillion cubic feet, to 26.6 trillion cubic feet in 2035. Growth in domestic natural gas consumption depends on many factors, including the rate of economic growth and the delivered prices of natural gas and other fuels. Natural gas consumption in the commercial and industrial sectors grows by less than 0.5 percent per year through 2035, and consumption for electric power generation grows by 0.8 percent per year. Residential natural gas consumption declines over the same period, by a total of 0.3 trillion cubic feet from 2010 to 2035.

U.S. natural gas production grows by 1.0 percent per year, to 27.9 trillion cubic feet in 2035, more than enough to meet domestic needs for consumption, which allows for exports. The prospects for future U.S. natural gas exports are highly uncertain and depend on many factors that are difficult to anticipate, such as the development of new natural gas production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

**Table 69: Coal Production by Region and Type, Reference case
(million short tons)**

Supply Regions and Coal Types	2009	2010	2011	2012	2013	2014
Northern Appalachia 1/	127.49	129.58	134.54	125.35	142.48	142.48
Medium Sulfur (Premium) 2/	4.58	14.45	17.68	16.63	18.65	20.05
Medium Sulfur (Bituminous)	48.31	40.24	36.97	34.08	33.08	31.19
High Sulfur (Bituminous)	74.6	74.9	79.89	74.65	90.74	91.23
Central Appalachia	196.66	186.44	186.41	178.08	167.44	155.09
Medium Sulfur (Premium) 2/	37.96	50.79	60.58	54.13	58.16	61.45
Low Sulfur (Bituminous)	25.83	17.24	18.56	18.24	15.68	12.97
Medium Sulfur (Bituminous)	132.88	118.41	107.27	105.7	93.6	80.67
Southern Appalachia	19.17	20.4	21.6	19.95	20.15	18.52
Low Sulfur (Premium) 2/	8.8	10.68	12.99	12.12	13.18	13.07
Low Sulfur (Bituminous)	0.7	0.42	0.85	0.83	0.72	0.55
Medium Sulfur (Bituminous)	9.67	9.29	7.75	7	6.26	4.9
Eastern Interior	106.26	109.78	117.62	109.93	112.98	111.05
Medium Sulfur (Bituminous)	14.07	11.76	12.24	10.41	10.61	9.06
High Sulfur (Bituminous)	88.75	94.02	102.05	96.29	99.25	98.64
Medium Sulfur (Lignite)	3.44	4	3.33	3.23	3.12	3.35
Western Interior High Sulfur (Bituminous)	1.6	1.63	1.1	1.05	1.6	1
Gulf	38.75	44.93	42.09	36.51	36.85	40.82
Medium Sulfur (Lignite)	23.51	31.16	31.84	24.39	22.56	30.24
High Sulfur (Lignite)	15.24	13.77	10.26	12.12	14.3	10.58
Dakota Medium Sulfur (Lignite)	30.29	29.3	25.15	33.06	28.18	29.84
Western Montana	39.14	44.38	48.99	43.21	48.83	52.4
Low Sulfur (Sub-Bituminous)	19.63	27.09	33.76	22.68	33.24	30.4
Medium Sulfur (Sub-Bituminous)	19.52	17.29	15.23	20.53	15.58	22
Wyoming, Powder River Basin	417.14	428.44	429.31	418.97	401.11	388.1
Low Sulfur (Sub-Bituminous)	413.09	425.5	426.88	415.6	399.11	385
Medium Sulfur (Sub-Bituminous)	4.04	2.94	2.43	3.38	2	3.1
Western Wyoming	13.97	14.09	9.32	8.96	10.34	10.95
Low Sulfur (Sub-Bituminous)	8.17	7.89	4.87	4.73	6.21	6.56

Medium Sulfur (Sub-Bituminous)	5.8	6.2	4.45	4.23	4.13	4.39
Rocky Mountain	49.98	44.51	43.18	40.57	34.15	33.64
Low Sulfur (Premium) 2/	0	0	0.21	1.91	2.17	2.5
Low Sulfur (Bituminous)	43.92	39.44	37.83	33.67	27.12	25.91
Low Sulfur (Sub-Bituminous)	6.07	5.08	5.14	4.99	4.86	5.22
Arizona/New Mexico	32.6	28.74	32.22	30.63	29.67	32.87
Low Sulfur (Bituminous)	7.41	7.76	8.49	7.57	7.67	8.05
Medium Sulfur (Bituminous)	6.5	4.93	5.99	5.85	5.7	6.06
Medium Sulfur (Sub-Bituminous)	18.68	16.05	17.74	17.21	16.3	18.76
Washington/Alaska						
Low Sulfur (Sub-Bituminous)	1.86	2.15	1.7	1.69	1.74	1.81
Subtotals: All Regions						
Premium Metallurgical 2/	51.34	75.92	91.47	84.78	92.17	97.08
Bituminous	454.24	420.04	419	395.36	392.03	370.24
Sub-Bituminous	496.86	510.18	512.2	495.04	483.18	477.24
Lignite	72.48	78.23	70.58	72.79	68.15	74.01
Low Sulfur	535.48	543.25	551.28	524.04	511.71	492.05
Medium Sulfur	359.24	356.8	348.66	339.82	317.92	325.08
High Sulfur	180.2	184.32	193.3	184.11	205.9	201.45
Underground	331.67	336.73	363.31	335.16	342.42	328.55
Surface	743.25	747.64	729.93	712.81	693.1	690.02
United States Total	1074.92	1084.37	1093.24	1047.97	1035.52	1018.58
Waste Coal	13.67	13.65	12.24	13.46	13.8	13.67

1/ Includes Pennsylvania anthracite.

2/ "Premium" coal is used to make metallurgical coke.

Northern Appalachia: Pennsylvania, Maryland, Ohio, Northern West Virginia.

Central Appalachia: Southern West Virginia, Virginia, Eastern Kentucky, Northern Tennessee.

Southern Appalachia: Alabama, Southern Tennessee.

Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky.

Western Interior: Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas (bituminous).

Gulf (lignite Only): Texas, Louisiana, Arkansas.

Dakota: North Dakota, Montana (lignite).

Western Montana: Montana (subbituminous).

Wyoming, Powder River Basin: Wyoming portion of Powder River Basin.

Western Wyoming: Wyoming other than Powder River Basin.

Rocky Mountain: Colorado, Utah.

Sulfur Definitions:

Low Sulfur: 0 - 0.60 pounds of sulfur per million British thermal unit.

Medium Sulfur: 0.61 - 1.67 pounds of sulfur per million British thermal unit.

High Sulfur: Over 1.67 pounds of sulfur per million British thermal unit.

Note: Totals may not equal sum of components due to independent rounding.

Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System.

38

Calpine Management Discusses Q3 2012 Results - Earnings Call Transcript

Executives

W. Bryan Kimzey - Vice President of Investor Relations

Jack A. Fusco - Chief Executive Officer, President and Director

John B. Hill - Chief Operating Officer and Executive Vice President

Zamir Rauf - Chief Financial Officer and Executive Vice President

W. Thaddeus Miller - Chief Legal Officer, Executive Vice President and Secretary

Analysts

Angie Storozynski - Macquarie Research

Keith Stanley - Deutsche Bank AG, Research Division

Neil Mehta - Goldman Sachs Group Inc., Research Division

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Paul B. Fremont - Jefferies & Company, Inc., Research Division

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Brian Chin - Citigroup Inc, Research Division

Gregg Orrill - Barclays Capital, Research Division

Ali Agha - SunTrust Robinson Humphrey, Inc., Research Division

James L. Dobson - Wunderlich Securities Inc., Research Division

Jonathan Cohen - ISI Group Inc., Research Division

Steven I. Fleishman - BofA Merrill Lynch, Research Division

Calpine ([CPN](#)) Q3 2012 Earnings Call November 6, 2012 11:00 AM ET

Operator

Good morning, and welcome to the Calpine Corporation Third Quarter 2012 Earnings Release Conference. My name is Brandon, and I will be the operator for today's call. [Operator Instructions] Please note that this conference is being recorded. I will now turn the call over to Mr. Bryan Kimzey. You may begin, sir.

W. Bryan Kimzey

It depends on the curve that you use, Angie, or the like. This is Thad. We said on -- in my prepared remarks, that we guided \$200 million range, and there's a view of -- toward the current markets are there's a view of what they have been and that's the reason for the \$200 million range.

Angie Storzynski - Macquarie Research

Okay. And the high end of that range is your view on the heat rates, the points that you were making about upsides for heat rates?

John B. Hill

I think the upper half of that range start to reflect what we think fundamentally is plausible this next year. And the lower half of that range reflects kind of where the current markets are, and we'll just have to see how it plays out. We all know that weather and others things can impact that but we'll [indiscernible].

Angie Storzynski - Macquarie Research

Okay. My second question about volumes, I mean, I'm struggling a little bit with projecting your volumes now that gas prices have recovered. I mean, can you give us a sense of what's, I mean, what type of volumes we -- you'll, you expect to reach for this year? And what type of volumes, say for, 2013 and also, how it links to your modeling suggestions? And you're clearly, there has been some reduction in those super peak premia, and which is linked to volumes, and if you could give us any sense of what kind of volumes you expect for next year.

Jack A. Fusco

Sure. Here's the best that I can probably do. In the first half of this year, when gas was level at \$3, we saw coal-to-gas switching everywhere across our fleet, including in Texas. At the current gas mark for next year, we expect we'll see some coal-to-gas switching in the East, but probably none in Texas. So the best, and obviously, there's our [indiscernible] some [indiscernible]. So unless gas price returns to the levels where it was last year, I wouldn't expect us to achieve the same volumes we achieved last year, or this year. On the other hand, I mean that we still got gas [indiscernible], we got switching in the East, so I would expect some work on it, maybe between 2010 -- excuse me, 2011 and 2012. If the current gas will liquidate; we'll just have to kind of see how it liquidates.

Angie Storzynski - Macquarie Research

And you mentioned in those modeling assumptions that there's been a change in your expected premium to on-peak spark spreads, while those premia are lower. Can you explain why that is, versus the second quarter of the disclosure?

John B. Hill

Yes, Angie, I don't -- there is no real change. The premium is going to be driven by what the amount of volume is that's driven. And so within any volume range, there shouldn't be a big change. But you'll have to decide how much volume we think we'll produce, which will be based on our gas price view. But to be clear, as we talked about last quarter, at a higher volume, the premium, because what -- we're guiding everybody off of the on-peak pricing, will be lower because more of those megawatt hours will come overnight. At lower volumes, more of those -- more of our production will be on peak, and so we think the premium will be appropriate.

Operator

From Deutsche Bank, we have Keith Stanley online.

Keith Stanley - Deutsche Bank AG, Research Division

Can you talk a little bit to the level of major maintenance expense and CapEx, the \$370 million for 2013? Would you say that represents a relatively higher year in the maintenance cycle? Or is that an average year to think about, going forward in the future?

John B. Hill