The MATS Conundrum, A Tongue-in-cheek Case Study

Paper #42

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Executive Summary

During President Obama's Administration, a number of new environmental rules have been proposed, finalized and/or published that appear to be targeted at coal and oil fired utility scale electric generating units (EGU's). To be fair, many of these initiatives were set into motion in previous Administrations, going back to the Clean Air Act Amendments of 1990. However, aggressive regulation of coal-fired units in particular has led to the common characterization that these requirements when taken together constitute a "train wreck" (see Figure 1) for the U.S. electric power sector. We are already seeing significant existing U.S. coal capacity permanently shut down and replaced with natural gas combined cycle – an outcome which appears to be the preferred energy policy of the Administration.

While the body of these regulations must be viewed in-total, four of these rules are summarized as context to the hypothetical case study presented in this paper. The four rules include; 316 (b) of the Clean Water Act, Coal Combustion Residuals, mercury and Air Toxics Standards (MATS) and the Cross State Air Pollution Rule.

In this paper, a hypothetical example is provided to illustrate why economic uncertainty and regulatory uncertainty are creating a conundrum regarding generator's future planning for major capital expenditures. The example is intentionally tongue in cheek, and represents no actual power plant or company. It is provided here to show how the small changes in multiple variables can be projected into the future to justify multiple paths forward – a decision tree that many generators are dealing with right now.

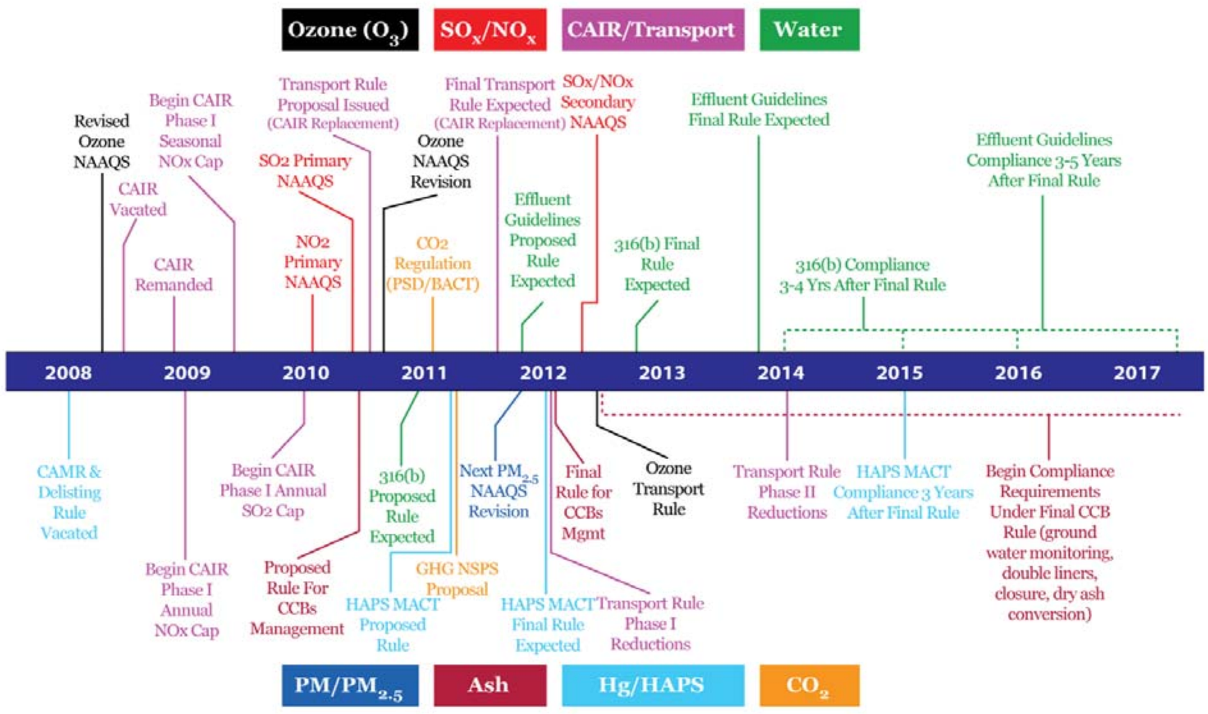
In ERM's presentation, the audience is asked put themselves in the position of a Power Company's Board of Directors, who, after being presented with a balanced view of the facts must vote whether to invest millions of dollars to upgrade an aging coal unit or whether to invest millions of dollars to develop a new combined cycle unit that will place the Company at the mercy of natural gas pricing. The MATS clock started one year ago and the MATS compliance clock is ticking. A decision is needed today – how will the Board vote?

Background

Given the central role of electric power in the nation's economy, and the importance of coal in power production, serious concerns have been raised about the cost and potential impact of new regulations under development by the Environmental Protection Agency (EPA). Several studies and analyses have been conducted by several third parties indicating anywhere from 30-95GW of power generation in the U.S. may be forced to retire. Indeed, the U.S. House of Representatives was so concerned that it passed the Transparency in Regulatory Analysis of Impacts on the Nation (TRAIN) Act of 2011 (H.R. 2401), which would have delayed for more thoughtful consideration several key elements of EPA's effort to regulate the electric power industry (and some would say to prescribe U.S. Energy Policy). Six of the rules which have drawn much of the recent attention are Clean Air Act regulations. Two others are Clean Water Act rules, and one is a Resource Conservation and Recovery Act rule covering coal ash. In an election year, it is uncertain when these rules may be promulgated or how they may be affected. The collection of new and proposed Clean Air Act regulations includes the GHG Tailoring Rule and proposed Greenhouse Gas New Source Performance Standards, revisions to NSR permitting, Utility MACT, revisions to the National Ambient Air Quality Standards for SO_2, NO_2 and $PM_{2.5}$ and the recently finalized Cross-State Air Pollution Rule regulating NO_x and SO_2. All together, these rules have been characterized by critics as a regulatory "train wreck", per Figure 1, that would impose excessive costs and lead to plant retirements over the next several years that could threaten the cost and reliability of electric capacity across the country. Since the addition of generating capacity or upgrades to existing capacity requires, in some cases, five or more years to implement, utilities and planners are wrestling with how to respond given the economic and regulatory uncertainties. This paper will take a look at four of these rules - 316 (b) of the Clean Water Act, Coal Combustion Residuals, Electric Generating Unit MACT standards and the Cross State Air Pollution Rule – as background to the hypothetical case study described at the end of this paper. The hypothetical case study has been presented to illustrate how slight changes to a multitude of projections and variables influence long-range capacity planning, and why electricity generators are faced with "the MATS conundrum".

Some in the electric power industry are questioning why EPA is undertaking so many aggressive regulatory actions in such a short timeframe related to coal. Supporters of the regulations assert that it is decades of regulatory delays and court decisions that have led to this point, and may also view the use of coal as a primary cause of global warming. Several of the current regulatory developments have been under consideration for a decade or longer since the Bush Administration, or are being reevaluated after an earlier action was vacated or remanded to EPA by the courts. EPA's regulatory impact analyses of these rules indicate that there are substantial benefits to public health and the environment which outweigh the economic impacts to consumers, the U.S. economy, and by extension to U.S. employment.

Figure 1. The so-called Regulatory "Train Wreck"



Sources: Edison Electric Institute 2010; Wegman, EPA 2003

The Brattle Group issued a report in May 2012, "Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS" which evaluates the feasibility of the large number of simultaneous pollution control retrofits and new generation that will be required in conjunction with the MATS rule. The Congressional Research Service (CRS) published a report in August 2011 entitled "EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?" which reviews several reports by industry trade associations and others that have discussed potential harm of EPA's prospective regulations to U.S. electricity supply, with emphasis on coal-fired generation. The Edison Electric Institute (EEI), which represents investor owned utilities, has attracted considerable attention by depicting a timeline in which multiple rules would take effect more or less simultaneously over the next five years. Congress has shown significant interest in these issues, and bills have been introduced that would defund or restrict EPA's ability to develop rules, and/or would legislate new regulatory analytical requirements such as the TRAIN Act mentioned above. By USEPA's own accounting, several of these rules are expected to be very expensive to comply with – costs that will be eventually handed down to consumers. Further, due to challenges and appeals as well as judicial decisions, rules when finally implemented may well differ enough from how they were originally proposed or even finalized that a plant operator's decision making regarding investing in pollution controls, capacity replacement using natural gas or facility retirement might look entirely different from what these analyses project. In addition, court challenges and appeals could delay implementation for years, creating further uncertainty. Even when final, EPA rules in many cases must be adopted by states and implemented over time through state-issued permits, and such states are authorized to tailor these rules so long as the resulting requirements are not less stringent. In USEPA's analyses, the primary impacts of many of the rules will largely be on coal-fired units more than 40 years old that have not installed state-of-the-art pollution controls. Such units may be inefficient by today's standards and arguably near the end of their useful life. The rules appear to provide incentives for generators to replace older units with more efficient combined cycle natural gas units, a development likely to be encouraged if the availability of shale gas continues to suppress the price of this alternative domestic fuel. This paper describes the four rules mentioned above that are at the core of the regulatory debate, with background on each rule and its requirements for context. The presentation associated with this paper describes a hypothetical case study to illustrate the magnitude of the variables and uncertainty that affect decision making regarding long range planning for a hypothetical 300 MW Pulverized coal-fired generating unit..

Coal fueled ~ 45% of the nation's electricity in 2010 as shown in Figure 2. The current fleet of electric power generators has a wide range of ages. Figure 3 depicts the age and capacity of electric generators by fuel type as of the end of 2010 according to the Energy Information Administration (EIA). From this source, about 530 GW, or 51% of all generating capacity, were at least 30 years old at the end of 2010. Further, most coal plants were built prior to 1980 and average 40 years of age. While the percentage of coal generation has declined since 2000 (from 52%), natural gas generation today is reported to equal that of coal. Most natural gas-fired capacity is less than 10 years old, while 73% of all coal-fired capacity was 30 years or older at the end of 2010. The 'other' category in Figure 2 includes solar, biomass, and geothermal generators, as well as landfill gas, municipal solid waste, and a variety of small-magnitude fuels such as byproducts from industrial processes.

Figure 2. Net U.S. Electric Generation by Fuel in 2010

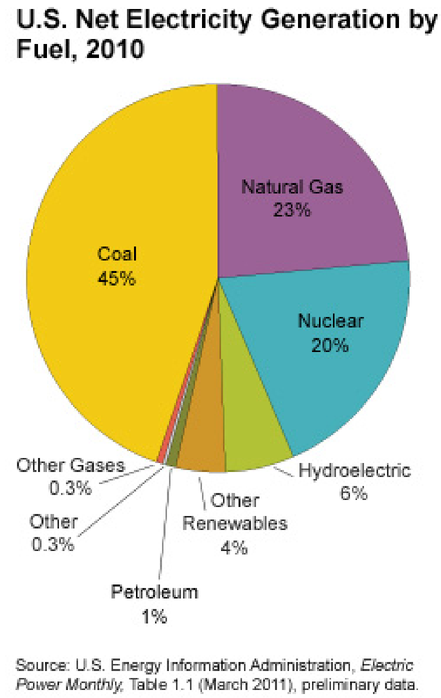
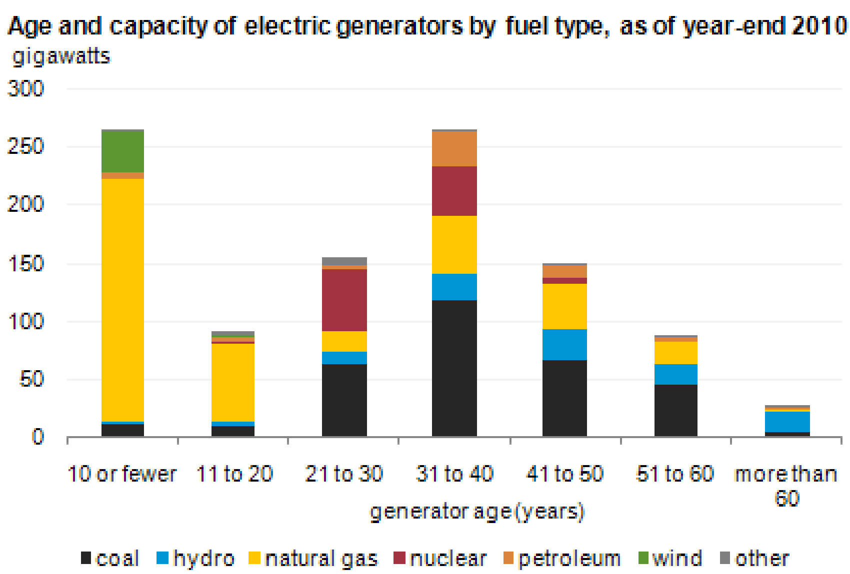


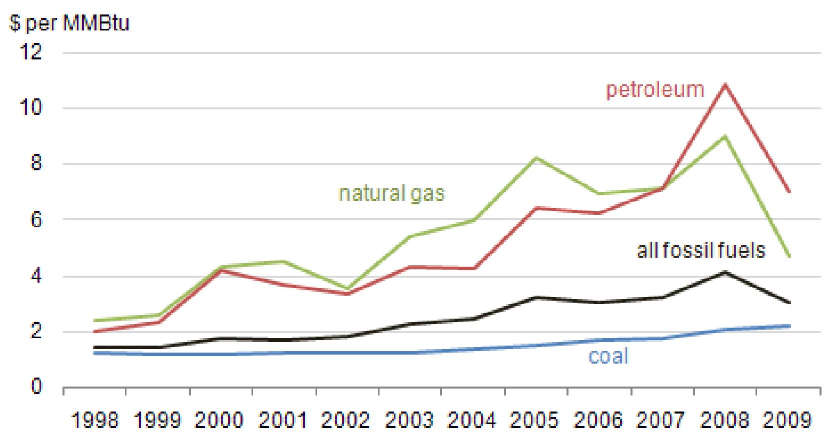
Figure 3. Average Age and Capacity of EGU's by Fuel Type



Source: U.S. Energy Information Administration, Form EIA-860 Annual Electric Generator Report, and Form EIA-860M (see Table ES3 in the March 2011 Electric Power Monthly)

Coal has historically been the lowest cost and least variable cost fuel source for power generation to consumers. In addition, due to their average age, the capital cost of these generating units has been largely or fully amortized, whereas natural gas prices have been volatile and most combined cycle plants have been built in the last 10-15 years. Data from the USEIA as shown in Figure 4 shows how inexpensive coal has been over the last 12 years in $/MMBtu. The average delivered cost of fossil fuels to electric power plants fell 26.0 percent in 2009, from $4.11 per MMBtu in 2008 to $3.04 per MMBtu (Table 3.5). Most of this decline relates to natural gas prices; in 2009 natural gas prices fell to about half their 2008 levels. Annual average costs of natural gas to the electric power industry peaked in 2008 at $9.02 per million Btu—the highest nominal dollar level in at least two decades—before falling to $4.74 per MMBtu in 2009. The average cost of coal rose very little between 2008 and 2009 from $2.07 to $2.21 per MMBtu, due to the prevalence of long-term contracts and the relatively small role of the coal spot market. However, there are other factors that affect the price of power, including the efficiency with which the plant converts fuel into electric power, maintenance costs, environmental compliance costs and the cost of operating the units, including ash management.

Figure 4. Average Cost of Fossil Fuels for the Power Sector 1998 - 2009



Source: U.S. EIA, Electric Power Annual 2009, April 2011, Table 3.5

Per the upcoming confluence of environmental regulations impacting the power industry, the critical uncertainties and tradeoffs surrounding compliance planning will shift away from second-guessing legislative efforts and a combination of difficult capacity decisions and potential reliance on emission credit markets. The EPA is developing these rules within the confines of existing law and in many cases subject to court ordered requirements and deadlines, *i.e.*, November 16, 2011 for the Utility MACT Standards. However, concerns related to the stalled economic recovery in the face of aggressive government regulation has prompted some in Congress to consider actively re-thinking their implementation and/or legislative alternatives such as The Transparency in Regulatory Analysis of Impacts of the Nation Act of 2011 (the TRAIN Act). The TRAIN Act would set up a government-wide committee to analyze the cumulative impacts – such as energy price increases and job losses – of a host of major new EPA regulations. In addition, the bill would delay two of the most expensive rules to give power plants enough time to comply with new rules, as well as providing guidance to EPA in writing the final version of the rules. National Economic Research Associates (NERA) conducted an analysis in September 2011 on behalf of the American Coalition for Clean Coal Electricity (ACCCE) of EPA's rulemaking path. The analysis relies on state-of-the-art modeling tools, as well as government data for almost all of its assumptions. NERA's analysis projects that EPA's Cross-State Air Pollution Rule (CSAPR) and proposed Utility MACT standards, coal combustion residuals, and cooling water intake requirements for power plants would, over the 2012-2020 period:

- Cost the power industry $21 billion per year;
- Cause an average loss of 183,000 jobs per year;
- Increase electricity costs by double digits in many regions of the U.S.;
- Cost consumers over $50 billion more for natural gas; and
- Reduce the disposable income of the average American family by $270 a year.

The NERA report concluded that new costs could lead to a 13 percent drop in coal-fired generation and a 26 percent increase in natural gas generation. In their analysis, electricity prices would rise by an average of 11.5 percent across the country. The study also projects that 144,000 power-related jobs would be lost over the next decade, despite claims from supporters that the rules will create construction work. Conversely, USEPA has estimated that the rules would have little impact on jobs, and could actually increase power industry employment in the long run.

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Analysts for the Clean Energy Group, a coalition that includes Exelon Corp. and six other utilities, have released a competing report saying that the costs are manageable and won't make the electric grid less reliable. They do not, however, conclude that there would be no cost increase to consumers. The Clean Energy Group report concludes that sixty percent of coal-fired boilers already meet EPA's proposed limit on mercury emissions, while 73 percent would comply with the rules for acid gases and 70 percent would have emissions below the particulate matter standards.

EPA also contradicts the NERA report, claiming that boiler compliance for the Utility MACT rule would cost $10.9 billion and Transport Rule compliance would cost another $2.9 billion per year. But EPA asserts that the monetized health benefits would greatly outweigh the costs to consumers – in the hundreds of billions of dollars.

According to Steve Miller, President and CEO of ACCE, "EPA is moving much too quickly to adopt several of the most expensive regulations ever written for coal-fueled power plants without understanding or explaining all of the harm they will do to our struggling economy,", and "EPA has failed to analyze the full impact of its own rules. The TRAIN Act is a common-sense bill that requires EPA to slow down and explain the full impacts of all these regulations on jobs and energy costs." Miller also added, "We expect that the TRAIN Act will be amended by the House of Representatives to include more protections for consumers and jobs, and ACCCE will support reasonable amendments to the legislation." ACCE also notes that due to investments made in clean coal technology in the last several years, emissions of major air pollutants from coal-fueled power plants have been reduced by 84 percent per kilowatt-hour of electricity.

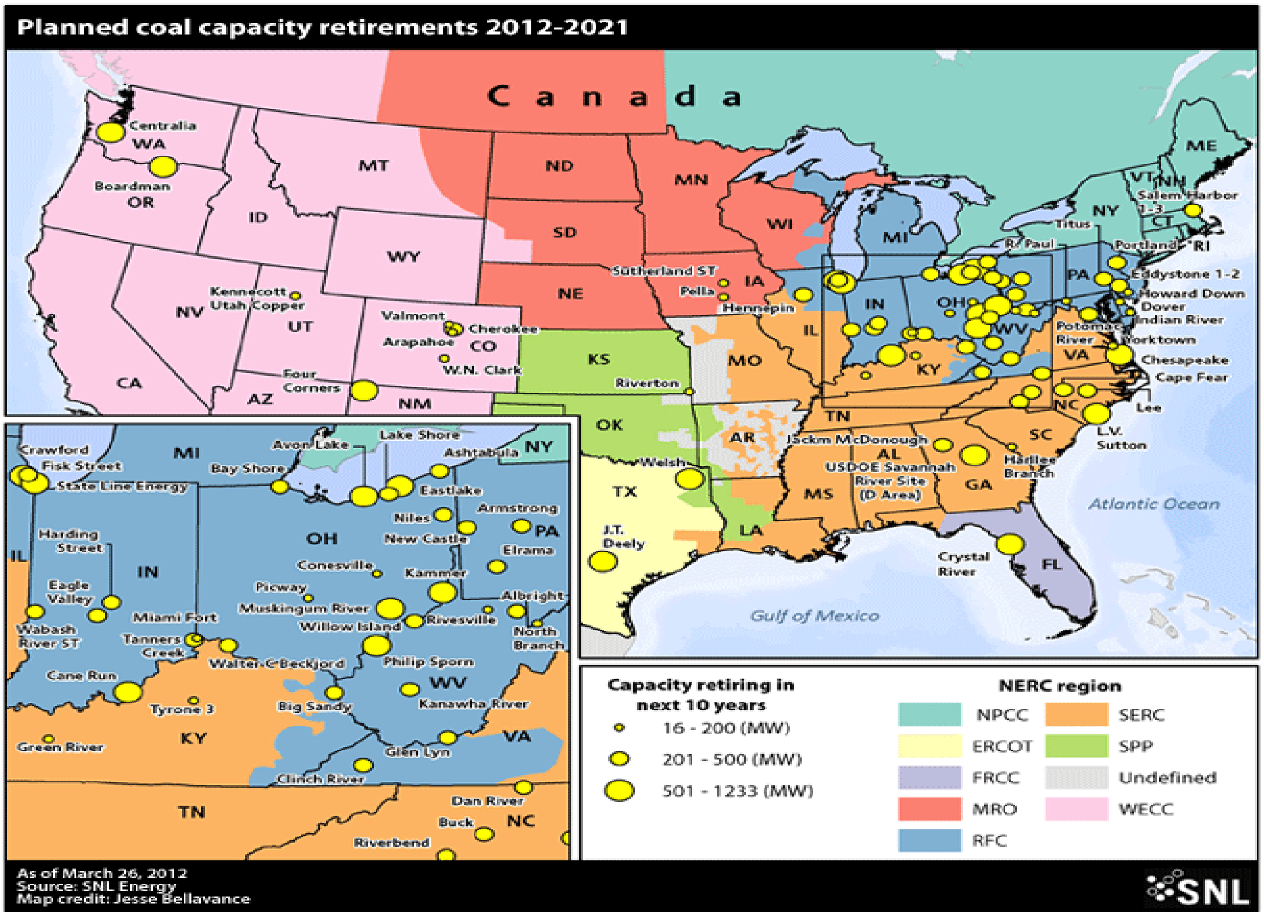
Coal Fired Power Unit Retirements

As a result of all the increasing regulatory scrutiny discussed above, this shifting landscape has forced U.S. power companies to take a hard looking at their generating fleets, resulting in a spate of announced coal unit retirements.

An SNL Energy analysis conducted in September 2011 found that U.S. power companies have already announced plans to retire nearly 26,000 MW of coal-fired capacity between 2011 and 2020 (see Figure 5) , an increase of roughly 11% from June 2011 when power companies had announced plans to retire approximately 23,000 MW of coal capacity. Announced coal retirements have nearly doubled since February 2011, when SNL Energy reported that approximately 14,000 MW of coal capacity was targeted for closure. This analysis was last updated in March 2012 and finds that U.S. power companies have formalized plans to retire nearly 25,000 MW of coal-fired capacity between 2012 and 2021, 1GW less than 6 months prior. Coal plant operators have increasingly used ambiguous language when referring to potential retirements due to the continued uncertainty in the regulatory environment as well as an election year.

Coal unit retirements are widely expected to continue to grow as electric generators decide how to comply with looming clean air regulations such as the EPA's Cross-State Air Pollution Rule and Mercury and Air Toxics Standards Rule, both of which are targeted at significantly reducing emissions from coal-fired power plants. In late June 2011, a federal judge approved a consent decree under which TVA will shut, retrofit or repower 16 additional coal-fired generating units by the end of 2018, on top of the 18 coal units the utility had already planned to retire.

Figure 5. Announced coal plant retirements over next 10 years



Source: SNL Energy March 2012 Analysis

Of the 25,000 MW of announced coal unit retirements in the U.S. between 2011 and 2021, the majority is slated to occur in the mid-Atlantic and parts of the Midwest and South.

The finalization of the EPA's CSAPR and MATS rules in July 2011 and December 2011, respectively, opened the door for a rush of new retirement announcements, but the reaction by generators has been fairly measured over the past few months, due in large part to the fact that both rules are in legal limbo. Opponents of CSAPR successfully had the rule stayed in late 2011, and coal interests are seeking to take a similar approach with MATS, which has been challenged in federal court but is not yet subject to a stay.

Several generators, however, have decided not to take a wait-and-see approach and are aggressively moving to close older coal units that they believe are not worth retrofitting. The most obvious example of that approach is FirstEnergy Corp., which since late January has announced plans to close more than 3,300 MW of coal capacity in West Virginia, Ohio, Pennsylvania and Maryland by Sept. 1. The company's decision to close a total of 21 coal-fired units on such a quick timeline is an unusual one compared to its peers, most of which have stretched their retirement plans over several years. FirstEnergy officials have attributed the decision to the short compliance time frame under MATS and to the need to give grid operator PJM Interconnection LLC enough notice about future plant closures.

Other power companies that have announced new coal unit retirement plans so far in 2012 include GenOn Energy Inc. and American Electric Power Co. Inc. GenOn on Feb. 29 announced plans to deactivate nearly 3,000 MW of coal capacity through various strategies including retirement, mothballing and long-term protective layup. Most recently, AEP on March 22 unveiled an updated coal retirement plan that formalizes much of the strategy the company first announced in June 2011While there are a significant number of coal units expected to be retiring over the next 10 years, the retiring units are largely older and less efficient. Despite the outcry over pressures caused by EPA regulations, the data is inconclusive regarding whether such large-scale retirement of units would or would not typically be retired within this time frame absent additional regulation. Overall, 178 units have been retired or are scheduled to be retired between 2011 and 2020, with the average expected age at retirement for these units ranging from 44 years to 66 years. This is well in line with average historical coal unit retirement ages of 45 to 55 years old. Units slated to retire in seven of the next 10 years have an average retirement age of at least 54 years old, at or above the upper bounds for typical retirement ages. However, these units are generally well maintained, and have typically been entirely amortized.

On a company-specific level, AEP, the nation's largest coal burner, leads the pack in amount of coal capacity scheduled to be retired between 2012 and 2016, during which the company plans to shutter nearly 5,100 MW of coal capacity. Other generators with a significant amount of retiring capacity during the 2012-2016 window include FirstEnergy at 3,352 MW, GenOn with 2,856 MW, Duke Energy with 1,908 MW, Dominion Resources Inc. with 1,669 MW and Progress Energy Inc. with 1,356 MW

Cross State Air Pollution Rule (CSAPR)

The Cross-State Air Pollution Rule (CSAPR) is presently stayed, but was designed to replace EPA’s major clean air initiative under the Bush Administration, the Clean Air Interstate Rule (CAIR). CAIR was promulgated in 2005, but was vacated and remanded to the agency by the D.C. Circuit Court of Appeals in 2008. On appeal, the court left the rule in place until such time as EPA promulgated a replacement. The agency proposed the replacement August 2, 2010 and it finalized the rule July 6, 2011.

Both CAIR and CSAPR, are designed to control emissions of air pollutants that may cause air quality problems in downwind states. The original, Bush-era rule did so by establishing region-wide cap-and-trade programs for SO_2 and NO_x emissions from coal-fired electric power plants in 28 Eastern states, at an estimated annual compliance cost of $3.6 billion in 2015. CAIR covered only the eastern half of the country, but since most of the coal-fired generation capacity lacking emission controls is located there, EPA projected that nationwide emissions of SO_2 would decline 53% and NO_x emissions 56% by 2015, as compared to nationwide emissions from electric generating units (EGUs) in 2001.

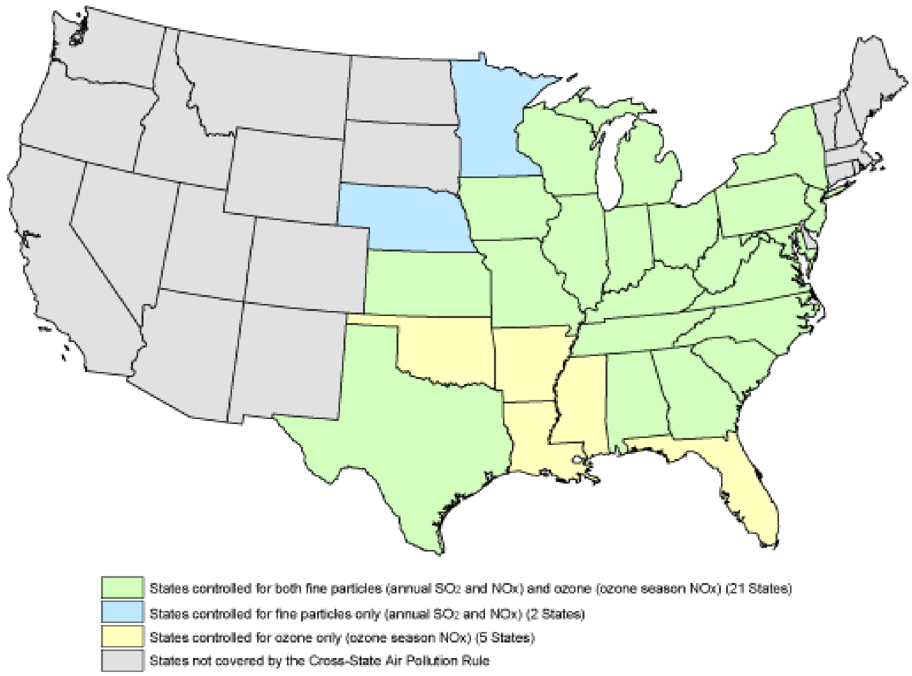
The replacement rule (CSAPR), finalized July 6, 2011, is a modified cap-and-trade rule that is significantly different than what was proposed in August 2010 under its predecessor, the Clean Air Transport Rule. It would allow unlimited trading of allowances within individual states, but interstate trading would be allowed only to the extent that a state remained within 18%-21% of its emissions caps. Limiting interstate trading was designed to address the D.C. Circuit's ruling, which found CAIR's interstate allowance trading program unlawful. The CSAPR rule applies to 28 states (adding Oklahoma, Kansas, and Nebraska to the 28 covered by CAIR, but removing Connecticut, Delaware, and Massachusetts from the CAIR group). Its annual compliance cost is estimated at $3.0 billion in 2012 and $2.4 billion in 2014.

CSAPR would leave the CAIR Phase 1 (2009-2010) caps in place and would set new limits replacing CAIR's second phase in 2012 and 2014, up to three years earlier than CAIR would have done. Some utilities spent millions of dollars installing controls to bank allowances, the fundamental currency of cap-and-trade, only to find that CSAPR has made those allowances worthless. The 2012 and 2014 requirements place particular emphasis on SO_2—emissions of which would decline significantly to 2.4 million tons in the covered states (73% below 2005 levels) in 2014. The CSAPR creates four separate trading programs for SO_2, annual NO_x and Ozone Season NO_x. For SO_2, state separated into two groups, Group 1 and Group 2.

In order to implement CSAPR quickly (starting January 2012), EPA is promulgating a Federal Implementation Plan (FIP) for each of the states: the FIP specifies emission budgets for each state based on controlling emissions from electric power plants. States may develop their own State Implementation Plans and may choose to control other types of sources if they wish, but the federal plan will take effect unless and until the state acts to replace it.

The CAIR Phase 1 rules (or the economic recession, the proliferation of inexpensive natural gas, or all of the above) appear to be having substantial effects. In August 2010, EPA reported that emissions of SO_2 had declined sharply in both 2008 and 2009: in the latter year, emissions from fossil-fueled power plants in the lower 48 states (at 5.7 million tons) were 44% below 2005 levels. NO_x emissions from the same sources reportedly declined to 1.8 million tons in 2009, a decline of 45% compared to 2005. The reductions occurred well in advance of CAIR's compliance dates: in fact, for both SO_2 and NO_x, the affected units had achieved about 80% of the required 2015 reductions six years ahead of that deadline. Further reductions of both SO_2 and NO_x can be expected as a result of these same factors. The Cross-State Rule is designed to skew the power market to further those reductions.

Figure 6. States Covered by the CSAPR



Source: US EPA Air Transport States Map (www.epa.gov/airtransport/statesmap.html)

NERC estimates that 1% of the coal capacity will retire as a result of CSAPR by 2015. EPA estimates that 4.8 GW of coal fired capacity would be uneconomic to maintain as a result of the rule. EEI conducted an analysis of the rule utilizing EPA's Integrated Planning Model and came up with similar results as EPA did through 2017; however, these results differ from 2017 and beyond as SCR is assumed to be required on all units to reduce NOx emissions. These results are speculative as EPA did not propose specific targets post 2014, leading to future uncertainty.

The U.S. Court of Appeals for the District of Columbia granted a last minute request on December 30,2011, by electric power producers to delay the CSAPR through Spring 2012 when the court is scheduled to weigh it's legal challenges.

MATS (Utility or EGU MACT)

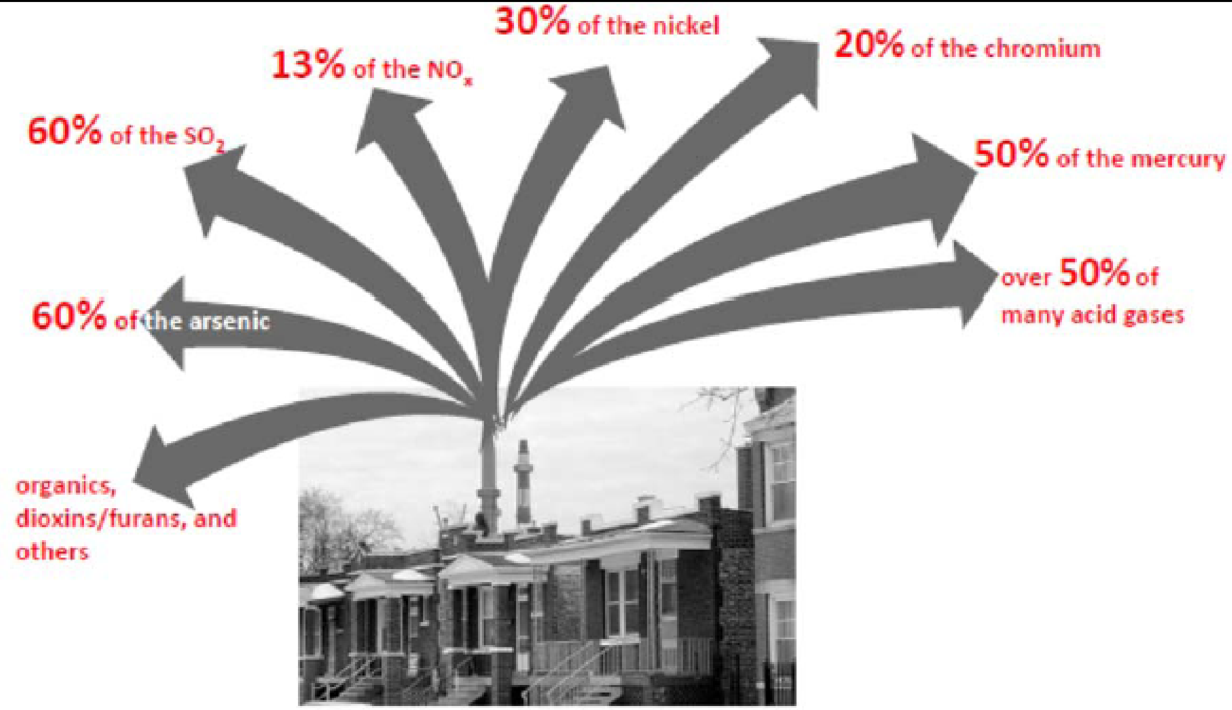
Another new regulation of concern to coal and oil fired power plant owners and operators is the MATS rule. The rule was first proposed and promulgated in 2005 as a cap and trade system to reduce emissions of mercury from coal fired power plants (which account for about half of the mercury emissions in the U.S.). However, under the court and EPA's interpretation of the statute, MACT standards are to be no less stringent pollutant by pollutant than the average emission limitation achieved by the best performing 12% of existing sources in the industry subcategory, (referred to as the MACT floor). The state of NJ and others challenged EPA on whether they could substitute cap and trade for a MACT standard and in a 3-0 decision the D.C. circuit court of appeals vacated the cap and trade rules in 2008.

The Utility MACT rule was re-proposed by EPA on December 21, 2011, published in the Federal Register as MATS on February 16, 2012 as a final rule, effective April 16, 2012. For coal-fired electric generating units (EGUs), it requires the control of three primary hazardous air pollutants: mercury (up to 91% reduction from uncontrolled emissions), hydrochloric acid as a surrogate for acid gases and PM as a surrogate for non-mercury metals. Figure 7 depicts the emissions from fossil fueled (coal and oil, which represents just 1% of electric generation) power plants as a percentage of total U.S. air emissions.

The final rule also calls for routine maintenance and work practice standards to ensure optimal fuel combustion in order to reduce emissions of dioxin/furans and other air toxics. In proposing the standards, EPA noted that while the requirements are stringent for those facilities lacking controls, it is asserted that 56% of the existing coal fired power plants in the U.S. are already capable of compliance. Therefore, EPA expects that the older, poorly controlled units will both invest and install pollution control equipment to comply with these standards or retire. In fact, EPA concluded that ~ 10 GW of older US coal capacity will be retired by 2015 as they will most likely choose not to invest in control technology. EPA's Regulatory Impact Analysis of the rule indicates that coal fired generation will decline about 2% compared to the estimated generation in the absence of the rule. EPA projected the annualized cost of compliance as proposed to be almost $11 Billion in 2015 and remaining on average of $10.5 Billion through 2030. The costs will go primarily to the installation of scrubbers and baghouses. EPA expects that 9% or 26 GW of coal fired units will install scrubbers and more than half of the coal fired units are expected to add baghouses along with activated carbon injection (ACI) or sorbent injection, *i.e.*, Trona injection. In the electric utility industry, these costs will eventually by paid for by consumers in the form of higher electricity rates.

The NERA study referenced above indicates that due to the potential costs of the four policies discussed in this paper, up to 39 GW of coal fired power plants will prematurely retire by 2015. Of the proposed rules, the Utility MACT will be the most costly and most likely to impact older, uncontrolled, coal fired generation.

Figure 7. Emissions from Fossil Fueled Power Plants as Percent of Total U.S. Air Emissions



Source: U.S. EPA, "Reducing Toxic Pollution from Power Plants," March 16, 2011, p.6

Clean Water Act

The U.S. Environmental Protection Agency (USEPA) recently proposed regulations, under section 316(b) of the Clean Water Act (CWA), designed to reduce the mortality of fish and other aquatic life entering cooling water intake structures of existing power plants. CWA Section 316(b) of the CWA addresses water withdrawals for cooling by point sources subject to the National Pollutant Discharge Elimination System (NPDES) program. CWA Section 316(b) "requires that the location, design, construction, and capacity of cooling water intake structures for facilities having NPDES permits reflect the best technology available (BTA) for minimizing adverse environmental impact." The USEPA's rule as proposed will cover large existing and newly proposed thermal generating units (including coal-fired, nuclear, and other steam units) with design flow rates of greater than 2 million gallons/day for the impingement part of the standard, and 125 million gallons per day for the entrainment part of the rule. In each case, an affected facility must use at least 25% of the water they withdraw exclusively for cooling purposes. The proposed rulemaking will require potentially significant compliance investments at plants with once-through intake systems. These investments will be based on the particular compliance strategies at each facility for applicable impingement mortality and entrainment (IM&E) compliance aspects of the rulemaking. The compliance timeline with the new regulation is up to eight years from the issuance of the final rule as defined by EPA, but will be ultimately determined by the states and phased in over time as units come up for new/renewal NPDES permits.

The proposed rule would require the development and execution of impingement mortality and entrainment studies - the costs for these studies can range from $250,000 to over $1 million per facility. Additional technology based studies will also be required with a cost range from $75,000 to $200,000 per facility. Annual IM&E costs will be driven by permit specific conditions and limits, with potential annual monitoring costs of $50,000 to $100,000 and up depending on numerous facility and permit specific factors. Additional O&M cost impacts associated with potential permit compliance conditions will be variable based on facility specific factors (for instance, below surface inspection of the intake structures in marine or navigable waters could present significant safety and cost constraints).

The proposed rule comment period closed on August 18, 2011. EPA received significant comments from a wide-range, and high number of, interested parties. Given the number of information requests/questions that EPA posed in the proposed rule, and the significant level of comments received, the final rule, scheduled for issuance in July, 2012, is anticipated to look significantly different than the draft rule.

The proposed rule covers "roughly 1,260 existing facilities that each withdraw at least 2 million gallons per day of cooling water," according to the EPA. The agency estimates that this rule will affect about 670 U.S. power plants. The current rulemaking process will be interesting to watch as previous CWA 316(b) rulemakings in 2004 and 2006 were successfully challenged in federal court and were remanded.

The proposed rule can be divided into three parts as shown in Figure 8. First, existing facilities that withdraw at least 25% of their water from an adjacent water body used exclusively for cooling purposes and that have a design intake flow of greater than 2 million gallons per day would be subject to an upper limit on the number of fish killed by "impingement" against intake screens or other parts at the facility. Impingement occurs when fish and other organisms "are trapped against screens when water is drawn into [a] facility's cooling system," according to the EPA.

Figure 8. Applicable Requirements of CWA 316 (b)

Facility Characteristic	Applicable Requirements
Existing facility with an AIF>125 MGD	Impingement mortality requirements (125.94(b)) and Entrainment Characterization Study 125.94.(c)
Existing facility with DIF>2MGD but AIF not greater than 125 MGD	Impingement mortality requirements
New Unit with a DIF> 2 MGD at an existing facility	Impingement and entrainment mortality requirements 125.94(d)
Other existing facility with a DIF of 2 MGD or smaller or that has an intake structure that withdraws less than 25 % of the water for cooling purposes	Case-by-case, best professional judgement

Note – AIF = Actual Intake Flow; DIF = Design Intake Flow

The owner of the facility will be required to select a very prescribed set of 'best technology available' to reduce those impinged organism deaths, including reducing "its intake velocity to 0.5 feet per second." (fish can swim away from the structure in water flowing at this velocity). This rule no longer allows restoration of a facility as a compliance alternative.

The second component of the new rule pertains to existing large users of once-through cooling water, at least 125 million gallons per day, whether it is ocean, river, or lake water. Those users must conduct studies that will determine site-specific technology alternatives, including conversion to the use of closed-cycle cooling (cooling towers), that will reduce aquatic organism entrainment mortality. The BTA option selected for use at a particular facility will be determined on a case-by-case basis.

The third and last requirement states that new units constructed at existing plants will be "required to reduce intake flow to a level similar to a closed cycle, recirculation system." In essence, new units must use cooling towers to handle the additional load, or the equivalent.

The EPA requires BTA compliance within eight years of the new rule's effective date. Also, the EPA estimates that more than half of the facilities affected by the rule already use technologies that will likely put them into compliance, although the EPA estimates covered all industrial plants, not just power plants. The rule does not apply to "new facilities," defined as those plants that began construction after January 17, 2002.

Coal Combustion Residuals

Coal Combustion Residuals, primarily coal ash, are currently considered exempt wastes under an amendment to RCRA, the Resource Conservation and Recovery Act. They are residues from the combustion of coal in power plants and captured by pollution control technologies, like electrostatic precipitators, fabric filters and scrubbers. Potential environmental concerns from coal ash pertain to constituents of ash from impoundment and landfills leaching into ground water, and potential structural failure of impoundments. The need for national management criteria was emphasized by the December 2008 spill of CCRs from a 50 year old surface impoundment operated by TVA near Kingston, Tennessee. The tragic spill flooded more than 300 acres of land with an estimated volume of 5.4 Million cubic yards of CCRs and flowed into the Emory and Clinch rivers.

Due to the ash pond failure at TVA's Kingston plant, the EPA released a proposed rule in April 2010 (published June 21 2010 in the FR) to regulate the disposal of CCRs. CCRs include fly ash, bottom ash, boiler slag, and flue gas desulfurization residues. In its proposal, the agency offered two potential regulatory approaches: one under RCRA Subtitle C and another under Subtitle D. Both approaches require that ash handling going forward be converted from wet to dry handling.

Regulation under Subtitle C would require that CCR be handled as a classified hazardous material, which would impact disposal costs and beneficial re-use options for ash at all plants. Facilities with surface impoundments would have 5 years to comply with requirements which include structural stability requirements. Existing landfills would be required to install groundwater monitoring within one year of effective date of rule, but do not need to install composite liners. New landfills or expansions would be required to install composite liners and groundwater monitoring before the landfill begins operation. Surface impoundments would be required to meet Land Disposal Restrictions (LDR) and liner requirements within 5 years of effective date of rule or close within an additional 2 years.

Regulation under Subtitle D would not treat CCR as hazardous but would still effectively require that plants convert from wet to dry handling and close existing ash ponds. Under this alternative there would be national minimum criteria governing facilities disposing of CCRs. The proposed engineering requirements are very similar to the Subtitle C option, *e.g.*, groundwater monitoring, liner and structural stability requirements; however, these requirements are self implementing. Facilities would be required to obtain certifications by independent professional engineers, document how various standards are met (operating record and State notified), and maintain a web site available to the public that contains documentation indicating that the standard is met. A subset of the Subtitle D approach, titled "D prime," would allow plants to keep their existing ash ponds in place until the end of their useful life. USEPA is expecting to publish the final rule in

2012. It is important to note that the Bevill exemption from regulation would remain in place for beneficial uses of CCRs. A summary of the requirements can be found in Figure 9.

Figure 9. Managing CCR Before and after EPA Ruling

Requirement	Subtitle C	Subtitle D
Effective date	Vary with State (1-2 years) Requires planning ahead	Six months after rule is promulgated Requires planning ahead
Enforcement	State and federal Monitoring and reporting plans	Citizen suits (inc. States) Monitoring and reporting plans
Impoundments before rule is finalized	Remove solids and meet LDR Retrofit with Liner within 5 years Develop corrective measures Prepare for phase out	Remove solids with composite liner or cease receiving CCR within 5 years Develop corrective measures Prepare for phase out
Impoundments after rule is finalized	Meet LDR and liner. Prepare for phase out	Install composite liner No LDR Monitoring and reporting plans
Existing Landfills	Groundwater Monitoring No liner requirements	Groundwater Monitoring No liner requirements
New landfills	Groundwater Monitoring and liner requirements Permitting and siting studies (wetlands, endangered species, cultural resources)	Groundwater Monitoring and liner requirements Permitting and siting studies (wetlands, endangered species, cultural resources)
Closure and post-closure	Monitored by States and EPA Develop closure plans	Self implementing Develop closure plans

EPA (Devlin, 2010) has estimated regulatory costs and regulatory benefits (e.g. groundwater protection avoided cancer cases, avoided future cleanup costs, increased beneficial use) for the next 50 years:

- Subtitle C (assuming no reduction in beneficial uses):
  - a) Cost: up to $1.5 billion/year.
  - b) Benefit: up to $7.4 billion/year.
  - c) Electricity price increase nationwide: 08%, on average,
- Subtitle D (assuming no reduction in beneficial uses):
  - a) Cost: up to $587 million/year.
  - b) Benefit: up to $3 billion/year.

c) Electricity price increase nationwide: 02%, on average

These estimations profoundly contrast with the results presented by NERA in the September 2011 report which states that the cost to the power industry would be $21 billion/year and double digit electricity costs increases in many US regions.

The Hypothetical Case Study

In this case study, we fabricated a hypothetical coal-fired utility boiler that is, or is about to be, subject to the four Rules described above. Any similarity to actual utility generating units in the U.S. is purely coincidental. Since the MATS compliance clock is already ticking, our hypothetical utility must commit major capital funds now to either upgrade the existing coal unit or replace it with a natural gas combined cycle unit.

We specified our example as a 300 MW pulverized coal-fired utility boiler (*i.e.*, neither a particularly large nor particularly small unit), constructed in 1962 (*i.e.*, nearing fifty years old), with marginal heat rate and low capacity factor. We assumed that the unit operates with once-through cooling, sluices ash from its 1973 vintage ESP to an on-site surface impoundment, and that it does not presently have natural gas service on site. We assumed that this unit burns low to medium sulfur local eastern bituminous coal, at a delivered cost of $70/ton.

We also assumed a series of stack test data that might be typical of such a unit, and compared those values with the proposed EGU MACT standards. For purposes of this example, we assumed filterable particulate matter (PM) emissions of 0.06 lb/MMBtu, mercury (Hg) at 4 lb/trillion BTU and hydrogen chloride (HCl) at 0.004 lb/MMBtu. These limits are all higher than the proposed EGU MACT limits for this source category. In addition, we note that this unit, located in the eastern U.S., will continue to be challenged for NO_x and SO_2 allowances under CSAPR, and will need to improve opacity (particulate emissions) from its older ESP.

Faced with the most immediate command and control style air regulation (MATS), we identified four compliance alternatives that the owner might consider; investment in air pollution controls and upgrades, re-powering of the existing infrastructure with 300 MW of natural gas combined cycle, construct a new 300 MW natural gas combined cycle unit at another, more favorable location, or contract with another outside supplier for 300 MW of offsite/renewable capacity.

Again, the exact requirements and timing of EGU MACT are (at the time of this writing) uncertain, and uncertainty similarly exists regarding implementation of the three other environmental rules. Further, the price of natural gas, and to lesser extent coal, over the 5 to 15 year planning horizon is highly speculative.

For this example, we assumed a range of air pollution control and plant upgrades that might be required to satisfy all four rules. Based on a “worst case”, “reasonable projected case” and “best case” scenario, we utilized EPA/EPRI’s Coal Utility Estimating model (CUECost), a tool purported to have an estimating accuracy in the range of +/- 30%. Based on CUECost, the APC upgrades alone could range from $16 million to $ 248 million depending on the ultimate implementation of the new and emerging air requirements alone. These upgrades were annualized to 46 million/yr (ten years).

Based on the worst case APC upgrades, and assuming status quo generation in future years, the annualized cost of the worst case upgrades and current coal price yielded a production cost from the upgrades to this existing unit of about 6.4 cents/net kW/hr.

We then performed a simple analysis for an equivalent 300 MW natural gas combined cycle plant, assuming construction cost of $700/kW (EIA data), and an average assumed price of natural gas delivered (including transmission and distribution) of $7.00/MMBtu through 2021 (based on a projected average gas price at the Henry Hub of $6.00 MMBtu. ERM is not in the business of making such projections, and it must be made clear that these are only crude assumptions on the part of the authors for purposes of illustration in this example. Based on the same annual output and amortization period, the new combined cycle plant also yielded a production cost of 6.4 cents per kW/hr.

The authors note that the assumptions involved represent a proverbial house of cards. The four rules may not end up as stringent as the projected worst case scenario (and will likely be at least somewhat less stringent than the worst case projected). Then again, the price of shale gas may be more or less than the $7/MMBtu value assumed. With retrofits, the Company would maintain its present operations and sunk investments, but would still own a boiler that may be nearing the end of its useful life. However, with natural gas the company will assume risk of fuel price volatility, and once converted from coal will be unlikely able to ever go back.

In conclusion, it is not at all clear which path is best for the company’s consumers in the long term – the EGU MACT conundrum.

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