Federal Policies and Regulations: the Future of Affordable and Reliable Electric Power

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AFFORD

Alliance for Fuel Options, Reliability and Diversity

AFFORD is an alliance of utilities that seeks to provide input into the regulatory and legislative framework in order to help craft rational and economically viable federal policies on energy and environmental issues

FEDERAL POLICES AND REGULATIONS:
THE FUTURE OF AFFORDABLE AND RELIABLE ELECTRIC POWER

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Executive Summary

Federal policies and regulations are threatening the future of affordable and reliable electric power by undermining the critical role fossil fuel-based generation plays in this country.

Multiple factors drive utility investment decisions. Fuel diversity to spread delivery and price risk, access to resources and infrastructure, access to electric transmission line capacity to export the power to load centers, and many other factors dictate the appropriate investment for each utility. In the context of these decisions the Environmental Protection Agency (EPA) has or is developing regulatory proposals that would both prohibit the consideration of coal as an electric generation resource and threaten the use of natural gas and oil. In essence, through ever-tightening controls, EPA is taking critical fuel choice decisions away from the private sector and in doing so has begun to dictate federal energy policy without a mandate from Congress.

Removing fossil fuels as a viable electric generation resource will undoubtedly lead to significant negative impacts on electric reliability, consumer costs and the economy. However, several converging factors – the current availability of low cost natural gas from shale production and an economic downturn lowering electric demand – are disguising these unavoidable impacts in the short term analyses relied upon by the EPA. Each serves to mask negative consequences of EPA's broad regulatory agenda.

> Diversity of fuel sources provides lower electric rates, which promote national economic growth and job growth. U.S. regulatory policy is now pushing electric suppliers in one direction with the potential for significant economic harm.

Additionally, as many utilities are hurriedly looking to transition to natural gas in the face of these factors, the Federal Energy Regulatory Commission (FERC) has failed to adequately assess the impact the rapid transition from coal to gas will have on the entire electric system. FERC has not identified which coal plants will be closing and whether there is sufficient natural gas pipeline capacity to support natural gas replacement plants. As increasing pressure is brought to bear on fossil fuel generation, and coal generation in particular, the ability to appropriately diversify by fuel type is increasingly constrained, raising the risks of over-dependence on one fuel and ensuing price volatility.

The U.S. Congress has long pursued a national policy that promotes fuel diversity in order to provide reasonable electric rates and to help assure national energy security. Disproportionately greater dependence on one fuel that has shown significant price and supply volatility could have substantial negative economic consequences. The fact is, diversity of fuel sources provides lower electric rates, which promote national economic and job growth. But U.S. regulatory policy is now pushing electric suppliers in one direction with the potential for significant economic harm.

EPA has established an unmistakable trend line: Coal is being taken out of the national fuel mix and EPA is establishing a regulatory framework that, ultimately, will dramatically reduce fossil fuel use throughout the economy. Most important, EPA is establishing a regulatory framework that permits it to take fuel choice decisions away from the private sector while it bases these decisions on a single determinant: the environment. But ignoring the equally important national goals of energy security, economic growth, lower consumer costs and electric reliability will lead to serious problems in the future.

RECOMMENDATIONS

The U.S. economic activity is directly related to the affordability and availability of electricity. Maintaining affordable and reliable power requires efficient government policies, diverse fuel options and reasonable long-term investment horizons. Unfortunately, federal government policies both in place today and under development are injecting significant uncertainty into utility operations, increasing costs and threatening reliability. To address these concerns the following steps should be taken:

- **Incentivize Technology Development -** It is in the nation's best interest to develop policies that maximize development of all fossil resources while minimizing ancillary negative impacts. Instead of forcing change through regulatory policy that relies on unproven or cost-prohibitive technologies, such as the EPA's proposed NSPS for GHG for new units, the government should increase research and development to prove technologies that are affordable and deployable to meet environmental goals for all fossil fuels. Once proven technologies exist, the government can facilitate a smoother transition toward better resource consumption in a manner that minimizes economic disruption.

- **Long-Term Integrated Energy Planning -** The U.S. government has multiple agencies governing electric policy but each operates independently. These agencies should be tasked with developing an integrated electricity plan that accounts for the long term policy goals of increasing energy independence; providing for reliable electric energy; maintaining a cost advantage over major international trading partners; and recognizing the need for fuel diversity, while at the same time providing a path toward a cleaner resource mix. Any clean energy resource mix should include broad choices that are regionally achievable including hydropower, clean coal, natural gas, biomass and nuclear, as well as traditional renewables.

- **Coordination of Major Regulatory Programs -** The legal framework governing electric generation has developed from Congressional, Judicial and Executive branch actions that date back nearly 100 years. But today, the disjointed nature of the various federal agency actions, the lack of integration between laws governing utility operations and the imposition of court decisions have resulted in a highly inefficient and, at times, conflicting operating environment. It is time for a better process. The government should begin to coordinate major regulatory actions in order to meet the integrated needs of the electric grid and promote a more predictable and efficient path forward.

- **Prudence in Regulatory Policy -** Long-term energy policy requires rational regulation to provide for reasonable investment certainty. Regulations that have no benefits, cannot be met or jeopardize the reliability of the electric grid serve to not only increase business uncertainty but also undermine the confidence in the regulatory process and the regulator itself. So too, regulations that fail to withstand legal scrutiny only increase regulatory risk. Simply put, the regulatory process appears broken. Regulators and policymakers must take steps to address this problem.

- **Reliability and Integration Assessment -** The U.S. government agencies that regulate the electric power industry should conduct a thorough assessment of what plants are closing and in what time frame, where those plants are located and whether those plants or the region are adequately served by natural gas pipelines and other required infrastructure that can adequately accommodate growing demand for natural gas.

Federal Policies and Regulations: the Future of Affordable and Reliable Electric Power

Electric utilities face a daunting set of decisions over the course of the next 10 years and beyond as existing infrastructure ages, electric demand grows and changing regulations require new electric generation capacity be built to assure electric reliability. Planning for new infrastructure and generation investment is already under way and decisions must be made to deploy technologies that are commercially available and environmentally responsible. These technologies also must meet the operational characteristics necessary to provide for an efficient, affordable and reliable electric grid. As utilities evaluate these decisions, pending federal regulatory changes pose the risk of threatening the future of our electric power system's dependability by undermining the critical role that fossil fuel-based generation plays in providing affordable and reliable electricity to the country.

> **"Fossil fuels have no part in America's energy future – coal, oil and natural gas are literally poisoning us. The emergence of natural gas as a significant part of our energy mix is particularly frightening because it dangerously postpones investment in clean energy at a time when we should be doubling down on wind, solar and energy efficiency."**
>
> —Robin Mann, Sierra Club President

Regulatory uncertainty is hampering the ability of the electric utility sector to reasonably plan, develop and operate generation resources. Regardless of the generation option, electric utilities face opposition to new resource development. Opponents of fossil fuels point to the opportunity to clean up the environment by transitioning away from coal-based electric generation to natural gas-based generation, but the use of natural gas also has detractors. In order to come to a sensible solution, policy leaders and the public must begin to understand the fundamental role that fossil fuel-based generation plays, and must continue to play, in providing electricity to the country.

Fossil Fuels Are Critical to Affordability and Reliability

Opponents of fossil fuel generation propose that the U.S. could meet its energy needs from renewable sources. However, according to the latest data from the Department of Energy, fossil fuels (coal, petroleum, natural gas and other gases) accounted for 68 percent of all U.S. electric generation, nuclear electric power 19 percent, and renewable energy 13 percent. Of the 13 percent of electric generation that comes from renewable sources, 63 percent comes from conventional hydroelectric power[1], a resource many from the environmental community oppose. This means that less than 5 percent of U.S. electricity is currently provided by wind, solar, geothermal and other renewable resources.

The U.S. cannot do without the 68 percent of the electric generation that keeps the lights on. Nor can we currently build a secure energy future on wind and solar generations as proposed by fossil fuel opponents – these resources are expensive and intermittent, meaning they are available only when the wind is blowing or the sun is shining, and electric power currently cannot be stored at commercial scale; it must be generated at virtually the same instant it is consumed. Under such a system, the margin of error is very slim and promises of future operational capability are no replacement for certainty. Until adequate electric storage technology is available, the promise of an energy future based solely on renewables is an illusion. At this time, the U.S. simply cannot meet all of its energy needs from renewable sources.

Federal Policy Issue:

Is it appropriate for EPA to issue regulations that have no benefit, to issue regulations that can't be met using today's technology and to continue to issue regulations without doing a cumulative impact analysis?

This paper serves to highlight the realities faced by electric utilities in making generation investments and raise the concern that the current Environmental Protection Agency (EPA) is further complicating the ability of U.S. electric utilities to rationally and objectively plan for new generation investment by unnecessarily complicating the regulatory environment and skewing analysis to restrict investment in fossil based resources.

This is the reality electric utilities face: The EPA has proposed rules that have no benefits,[2] has issued regulations it concedes cannot be met[3] and has failed to conduct a comprehensive evaluation of the impacts of its accelerated regulatory program. EPA has also failed to comprehend and adequately account for the impacts of its regulations on the existing fleet of electric generation units and on the

[1] Source: EIA Annual Energy Outlook 2012

[2] EPA: "It appears very likely that the costs – and benefits – of the proposed standard will be zero." U.S. EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance* for Greenhouse Gas *Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-452/R-12-001, March 2012, ("RIA") page 5-33.

[3] See, for example, King and Spalding Analysis found at http://www.kslaw.com/library/newsletters/EnergyNewsletter/2012/September/article1.html

development of new electric generation resources. These actions will have negative implications beyond the operation of utilities. They will negatively impact the availability and affordability of electric power for ordinary citizens, businesses and even the U.S. government.

EPA's Fossil Fuel Regulations

Recent EPA regulations have established an unmistakable trend: Coal is being taken out of the national fuel mix – a policy that has never been sanctioned by Congress. Further, EPA is establishing a regulatory framework that, ultimately, will dramatically reduce the fossil fuel use not only in power plants but also eventually throughout the entire economy.

Removing coal and other fossil fuels as an electric generation resource will undoubtedly lead to significant negative impacts on electric reliability, consumer costs and the economy. However, the current availability of low-cost natural gas from shale production and the lowered electric demand resulting from the economic downturn are both disguising these unavoidable impacts in the short-term analyses relied upon by the EPA. Each of those factors serves to mask negative consequences of EPA's regulatory program.

EPA has maintained that announced coal plant closures and the dearth of planned new coal plants are the result of market forces. This in turn has lead EPA to claim that its most far-reaching proposed regulation, greenhouse gas (GHG) new source performance standards (NSPS) for new fossil fuel plants, has no cost and therefore little impact on coal plant closures. EPA also maintains that this regulation has no impact on the ability to build new coal plants, but nothing could be further from the truth. EPA's regulations, particularly the final Electric Generating Unit (EGU) Mercury and Air Toxics Standard (MATS) rule for new and existing coal plants and the proposed GHG NSPS for new fossil fuel plants, have created higher costs as well as vast regulatory and litigation uncertainties that together prevent construction of new plants and cause escalated and unnecessary closure of existing coal plants.[4]

Many of the major regulations affecting utilities remain proposed or in flux for extended periods due to EPA delays in issuing rules, reconsideration and court challenges of already-issued rules or court remand. As a result, it is difficult to provide exact figures on the anticipated cost increases and reliability impacts of a fluid regulatory agenda. EPA has created regulatory uncertainty that will lead to greater

[4] EPA has established a GHG NSPS of 1,000 pounds of carbon dioxide per megawatt hour for new coal plants that is based on the GHG emissions from a new gas-fired combined cycle unit. Industry experts as well as EPA agree that this standard cannot be met now or in the foreseeable future by a new coal-fired plant using any commercially available control technology. EPA's GHG NSPS for new units is a de facto prohibition against new coal-fired generation.

than necessary plant closures while truncated compliance timelines will unnecessarily raise the costs of compliance for existing plants. The scope of the regulatory push and the insufficient compliance periods threaten near- and long-term electric rate increases and reliability for customers.

Regulation	Status
National Ambient Air Quality Standards for:	
Ozone	proposal due 2013, final due 9/14
Sulfur Dioxide (SO2)	final 6/10
Nitrogen Dioxide (NO2)	final 2/10
Particulate Matter (PM)	final 12/12
Cross State Air Pollution Rule (CSAPR)	Vacated 8/12, rehearing denied
GHG Rules :	Upheld DC Court of Appeals 6/12,
Endangerment Finding	rehearing denied 12/12
GHG Tailoring Rule	
"Johnson Memorandum"	
New Source Performance Standards for:	
GHG for New Plants	proposed 4/12, final due 3/13
GHG for Existing Plants	Unknown, subject to Consent Decree
Gas Turbines/Combustion Turbines	proposed 8/12
National Emissions Standards for Hazardous Air Pollutants (NESHAP),	
Mercury and Air Toxics Standards (MATS)	final 2/12, new units in reconsideration
Coal Combustion Residuals Rule	proposed 6/10, final due 6/13
Cooling Water Intake Rule [316(b)]	proposed 4/11, final due 5/13
Power Plant Effluent Limitations Guidelines	proposal 4/13, final 4/14

Most important, EPA is establishing a regulatory framework that permits it to take fuel choice decisions away from the private sector while it bases these decisions on a single determinant: the environment. Ignoring the equally important national goals of energy security, economic growth, lower consumer costs and electric reliability will lead to problems in the future.

U.S. Electric Generation Investment Decision-Making

Electric utilities have historically invested in large, centrally located generation stations. These investments require substantial capital commitments and generally have actual life cycles that extend 40 to 50 years or more. These assets require substantial due diligence prior to permitting and development. It is a common business practice in the electric utility sector to develop integrated resource plans that look out as much as 10 years in advance of making a decision.

Major Parameter Decisions for New Plant

<u>Energy source or fuel</u>

- Common fossil fuels (coal, oil and natural gas)
- Nuclear fuels (uranium and thorium)
- Elevated water (hydroelectric)
- Geothermal steam
- Other renewable, advanced technology or nonconventional sources

<u>Generation system</u>

- Steam-cycle (e.g., steam-turbine) systems (with or without cogeneration type steam for native heating and industrial steam loads)
- Hydroelectric systems
- Combustion-turbine (e.g., gas-turbine) systems
- Combined-cycle (e.g., combined steam- and gas-turbine) systems
- Internal-combustion engine (e.g., diesel) systems
- Advanced technology or nonconventional sources

<u>Unit and plant rating</u>

- Capable of serving the current expected maximum electrical load and providing some spinning reserve for reliability and future load growth considerations
- Capable of serving only the expected maximum electrical load (e.g., peaking unit)
- Capable of serving most of the expected maximum load (e.g., using conservation or load management to eliminate the load that exceeds generation capacity)

<u>Plant site</u>

- Near electrical load
- Near fuel source
- Near water source (water availability)
- Near existing electrical transmission system
- Near existing transportation system
- Near or on existing electrical-generation plant site

Business and regulatory risks, demand uncertainty and fuel price volatility all combine to make an accurate forecast of the best new generation resource difficult. Some of these risks can be hedged, others not so easily. History has demonstrated that reasoned and rational decisions based on current assumptions can prove to be erroneous – and costly.

One common strategy to minimize risk within the utility sector is to seek to develop a diversified portfolio of generation resources as a mechanism to minimize fuel and regulatory risk. However, as increasing pressure is brought to bear on fossil fuel generation, and coal generation in particular, the ability to diversify by fuel type is increasingly constrained. In the current business climate the options for new baseload investment are becoming so limited that the lack of options creates its own risk: a risk of overreliance on a single commodity.

Understanding this planning horizon and the factors associated with resource decisions is critical to understanding how utilities operate. Unfortunately, EPA has not taken into account this important list of issues when evaluating the impact of new regulations on utilities. Rather, EPA's analysis is conducted on a macro basis, relying on assumptions that are often incorrect.

ELECTRIC MARKETS COMPLICATE PLANNING AND ANALYSIS

The pressures of navigating environmental requirements can be compounded in regions that fall within organized markets (i.e., are covered by regional electric transmission organizations, like MISO or PJM) and, even further complicated in states that fall within RTO regions *and* have fully competitive retail electric service.

In the first instance, the market signals that are supposed to result in a functioning wholesale electric market do not always marry up with environmental realities, and the decisions about how generation facilities are dispatched are governed largely by the market. In the second instance, state regulators have largely surrendered their ability to require the construction of new generating assets, instead leaving those decisions to be driven by the market.

An example of market signals and environmental regulations serving cross purposes is PJM's Reliability Pricing Model capacity auction. PJM conducts a three-year forward auction for capacity. One component of the auction is the identification of congested areas called Locational Deliverability Areas, which are isolated from the balance of the RTO and may reflect a higher price. This is designed to send a signal that generation and transmission upgrades or additions are needed in the area. Unfortunately, these congested areas may overlap with areas that have been designated non-attainment for certain pollutants, increasing the complexity and difficulty of siting new generation.

Additionally, in RTO regions, the process for interconnecting new generation resources to the transmission grid is overseen by the RTO who coordinates a series of studies with the transmission owner to identify the transmission system upgrades and costs necessary to accommodate the added load. The interconnection queue for new generation is overflowing because speculative resources can enter the queue. The process can be timely and inefficient, resulting in significant delays for needed new generation.

These realities are anticipated to have a greater impact as older coal generation closes and load grows with economic improvement in hard hit regions, yet EPA fails to account for these problems.

The table **Major Parameter Decisions for a New Plant** addresses the highest-level factors that must be analyzed. For example, locating a new generation station near the demand source may seem prudent until a factor such as a lack of access to cooling water or natural gas transmission lines eliminates that option.

The Differing Roles of Baseload, Peak and Renewable Plants

Effective analyses must consider the role the new generation resource will fill in meeting demand.

Baseload plants such as nuclear and larger coal and hydro plants have different characteristics than plants used for peaking purposes. The baseload plants require high initial investment but offer reliability and longevity with a lower operating cost. On the other hand, peaking units such as hydroelectric plants and smaller natural gas combustion turbines are generally only used when electric demand is high. These rapid-response units often have higher operating costs but lower capital costs.

Much has been made recently about renewable resources filling electric demand needs, but these resources cannot be counted on to consistently deliver power. As a result, they must be backed up with a redundant power supply that can be dispatched when the renewable resource is not available. Redundant power supply is expensive, and policymakers have not yet begun to require intermittent resources like wind and solar to pay for the cost of providing backup power supply when bidding into organized markets.

Further, for utilities that operate in organized markets, intermittent resources can create market distortions as penetration rates begin to climb. Variable resources can not only be forced to go from full power to zero production in a matter of minutes (e.g., when wind speed subsides), they also can generate power when the supplier does not need it. During these periods, variable generator owners may actually have to pay other utilities to take their power. This economic inefficiency is another factor weighed by utility planners that may dissuade utilities from overweighting variable resources.

Why Investment Decisions Require Site-Specific Analysis

Perhaps as important as understanding the series of decisions that must be made prior to developing new generation resources is understanding that each decision is not only utility specific but also *geographically* specific. EPA has consistently concluded that the new regulations issued in the last four years would not imperil grid reliability.[5] However, EPA modeling does not provide regional or sub-regional analysis of impacts of its own rules on the electric grid.

[5] See, for example Senate Environment and Public Works Committee Testimony found at http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=4d9aa9ac-ff5a-41c3-a810-6b2d4bb8313f

An example of this concern can be found in the analysis[6] done by the Midwest Independent System Operator (MISO), which is the Regional Transmission Operator (RTO) for the Midwestern regional electric market, which is comprised of 13 States and one Canadian province. In the analysis, MISO evaluates the impacts of the anticipated closure of substantial generation resources within its footprint and models the requirements to replace that generation.

MISO utilities currently plan to retire 12.6 GW of coal-fired generation in the near term, amounting to about 9 percent of total current capacity. In contrast to EPA's assertions, MISO is concerned this reduction presents reliability concerns for the region. MISO planners assume that the retired capacity will be replaced by natural gas generation given the inability of utilities to build other fuel diverse baseload capacity in a compressed time period. But MISO analysis concludes there is insufficient mainline natural gas pipeline capacity to serve in the 12.6 GW coal-to-gas retirement scenario.

Worse, in the short term, more than 65 percent of the pipelines currently supplying gas into the Midwest have insufficient capacity to fully meet the needs of the existing embedded units operating at expected capacity factors. For the period 2016-2030, almost 90 percent of the pipelines have insufficient capacity for the existing embedded units plus the incremental 12.6 GW coal-to-gas retirement scenario.[7] In this instance, as in many others, EPA has not sought such pertinent information.

The MISO is not alone in challenging EPA's conclusions that reliability will not be impacted by new environmental regulations. A Sept. 1, 2011, study by ERCOT, the regional entity having responsibility for the reliable operation of most of the Texas grid, concluded that Texas is at risk of rolling blackouts this winter and next summer as a result of EPA’s rules.[8] Similarly, the Southwest Power Pool (SPP), the RTO approved by FERC to plan and operate the regional transmission system and wholesale electric market in eight Southwestern states, informed EPA on Sept. 20, 2011, that its analysis regarding the impact of the MATS rule on the region "indicates serious, negative implications to the reliable operation of the electric grid in the SPP region raising the possibility of rolling blackouts or cascading outages that would likely have significant impacts on human health, public safety and commercial activity.”

What is plain from this example – and there are many more – is that EPA’s one-size-fits all regulatory approach confounds the geographically specific planning necessary for successful management of electric utilities.

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[6] https://www.midwestiso.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Embedded%20Gas%20Units%20Infrastucture%20Analysis.pdf

[7] Later in this paper we will discuss the complication regarding cost recovery for major pipeline infrastructure projects to serve new gas-fired generation, which is currently an uncertain process. Infrastructure providers usually seek to recover pipeline development costs over 10 to 15 years but utility cost recovery is typically for longer terms.

[8] *See* ERCOT, *Impacts of the Cross State Air Pollution Rule on the ERCOT System*, Sept. 1, 2011

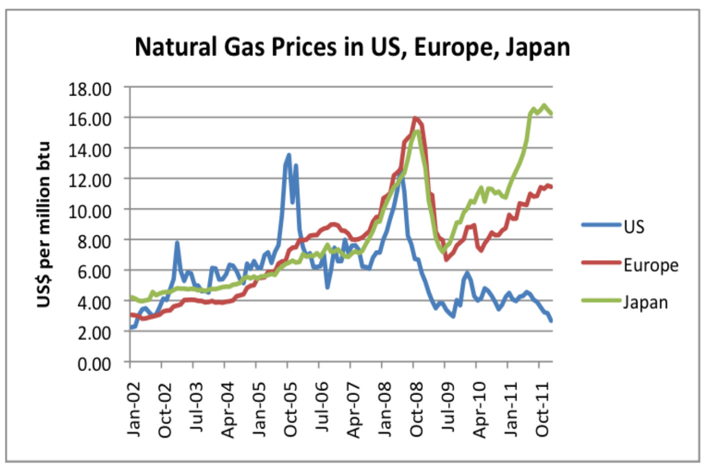
Natural Gas Boom: Changing Electric Generation Economics

Recent regulatory actions and changing market conditions have begun a process of change within the electric utility sector that is unprecedented in modern times. Generation of electricity from different fuel sources has rapidly changed in the past several years as the costs of natural gas have declined substantially. So too, regulatory changes are forcing the closure of an unusually large number of coal-fired power plants. Net electric generation from coal declined 14 percent from 2007 to 2011. While coal remained the largest source of electricity generation through 2011, natural gas became the second largest source of generation in 2006. In 2012, natural gas and coal generation reached an unprecedented equal level.[9]

Today, the low price of natural gas and the lack of available baseload generation investment alternatives are compelling utilities to develop natural gas-fired generation. In today's environment, natural gas units are generally less expensive and quicker to license and build than a conventional coal unit or nuclear power. However, the benefits of rapid deployment and lower development cost may not bear out the risk of unstable fuel availability and price volatility. Additionally, the consequences of price volatility become more pronounced as utilities are more heavily vested in one-generation resource.

Natural Gas Pricing Difficult to Accurately Forecast

Consider the graph to the right. Natural gas prices have fluctuated dramatically over the last decade. In contrast to several years ago, U.S. domestic resources of natural gas are presumed to be robust provided that reserves can be economically developed. This supply of inexpensive natural gas has been a boon for the economy, but before making a major commitment to new gas generation, electric utilities must consider how long such low prices can be sustained – and there is no certainty on that question.



The American Gas Association President Dave McCurdy has said natural gas companies are losing money at current prices.[10] Forbes energy analyst Richard Finger produced compelling information suggesting a combination of substantially decreased drilling rig deployment and an unforeseen increased well

[9] Source: EIA Energy Outlook 2012
[10] http://www.eenews.net/tv/transcript/1571

depletion rate in fracked wells will result in higher gas prices.[11] If it were possible to establish long-term hedges for natural gas pricing, this risk might be tenable, but contracts for natural gas that extend beyond five years are less common and more costly.

Perhaps as important as the sustainability of gas development is the huge arbitrage opportunity that exists between domestic and international markets in gas pricing. Note the significant difference between U.S. and European and Japanese natural gas pricing. Today, U.S. exports are constrained by Liquefied Natural Gas (LNG) terminal capacity, though plans are under way to permit increased export capacity. To the extent that the U.S. develops export capacity for LNG, pricing of domestic natural gas will be subjected to upward pressure as gas is exported to markets where it can be more profitably sold by producers.

The Bureau of Land Management has proposed tougher rules for hydro-fracking on federal lands, and EPA is examining tougher regulation of natural gas fracking. Additionally, the administration and some in Congress have suggested the intangible drilling cost tax credit should be eliminated, which would cut available capital investment drastically. Given additional federal government regulatory challenges, natural gas production at today's rates is not assured.

If natural gas prices become volatile again, utilities must also be concerned about heavy gas reliance leading to downgrades from credit rating agencies. Taking coal out of the fuel mix deprives utilities of a critical hedging strategy, limiting their ability to better manage risk and exposing them to potential credit downgrades.

Pipeline Capacity Concerns

Beyond price volatility, there are also natural gas delivery concerns. One example: In December 2012, the New England Independent System Operator (NE ISO) formally expressed reservations about the increased reliance of electric systems on natural gas, and suggested increased demand on the system due to extreme cold weather could also be problematic.[12] Specifically, the NE ISO noted the combined reliance on gas by homes for heating purposes and by utilities for electric generation creates a potential for demand to exceed capacity.

If large parts of the U.S. economy are to shift to natural gas, sufficiently low long-term prices that maintain the advantage of gas over other fuels are likely to be required. However, the increases in demand associated with these sectoral shifts in favor of gas use could result in prices also increasing, perhaps bringing into question the economic advantages available to potential users of natural gas. Further, if prices were to remain low in the long-term, industry might not be able to sustain production. If wellhead prices are too low for developers to make sufficient profits, exploration and development activities might slow and production might be capped.

CRS Report to Congress: Natural Gas in the U.S. Economy, Opportunities for Growth, 11/6/12, p. 12

[11] http://www.forbes.com/sites/richardfinger/2012/10/14/8-natural-gas-were-right-on-schedule/
[12] http://www.naylornetwork.com/app-ppw/articles/index-v2.asp?aid=199554&issueID=23358

So why are so many utilities making such significant investments in new natural gas facilities if there is some doubt regarding the availability, deliverability and price of natural gas? The answer is that **at this time natural gas electric generation is effectively the only viable choice for baseload capacity to replace retiring coal plants**, as it is currently impossible to build new coal, the NRC has stopped licensing new nuclear plants and few other options exist.

Competition for Resources

Among the many benefits of the newfound natural gas supply and associated lower prices is the resurgence of domestic manufacturing in the U.S. After a long period of economic decline, manufacturers that rely on natural gas as a primary component of the manufacturing process are starting to return to the U.S. Industrial demand for natural gas can have a significant impact on pipeline capacity regionally. While industrial customers express concern that utility generators are less sensitive to price fluctuations, utilities are concerned that constant supply needs will allow manufacturers to secure contracts for pipeline capacity to the exclusion of the electric utility.

Convergence of Natural Gas and Electric Sectors

The Federal Energy Regulatory Commission (FERC) has initiated an effort to address the many issues that arise from a growing convergence of operations between natural gas pipelines and electric companies. The FERC initiative is necessary because the two industries have different modes of operation. Experience indicates there is a need for greater gas-electric harmonization of business practices to address important questions of reliability.

The purpose of greater harmonization is to improve reliability as well as to promote necessary infrastructure expansion. FERC held five regional conferences in 2012 to examine these issues and has directed RTOs and ISOs to report progress on gas-electric coordination efforts. Additionally, FERC will convene two technical conferences to further explore improving communications between the electric and natural gas industries and to address harmonizing natural gas and electric scheduling days.

Electric industry stakeholders are not united in their views on how FERC should address issues related to the greater interdependency of the gas and electric sectors. While some believe there is a need for a national framework, others insist regional markets are so distinct that issues should be addressed on a region-by-region basis. Many believe there is a need for

Questions Regarding the Gas/Electric Nexus

Can pipelines provide capacity to power generators on short notice, especially during periods of peak demand?
Can pipelines adapt to frequent and highly fluctuating changes in gas flow?
Should utilities fully compensate pipelines for the additional costs that special services and additional nomination cycles may require?
Should utilities be able to bid generation into the market if they don't have firm gas transmission capacity?

adoption of communication protocols, operating standards and service offerings that reflect growing interdependence.

It is not certain that pipelines will be willing to accommodate the stringent demands of power generators and RTOs. Traditionally, gas pipelines do not build for intermittent load and electric peaking units do not contract for firm transmission access. What happens when electric peaking units cannot run because pipeline capacity is maxed out? These are not theoretical concerns; the state of Texas has already experienced reliability events compounded by disruptions in natural gas deliverability.

Power generators argue their special needs require pipelines to offer them more flexible service than is provided to other shippers. They need purchasing flexibility and capacity assurances for intraday nominations, hourly gas flows for more balancing flexibility and gas diversion and deliverability. Many gas-fired electric generators often operate sporadically and on short notice, differing from traditional gas shippers in "unprecedented ways." Both industries will need to adjust their operating practices to circumstances that are changing more rapidly than usual due to the landscape created by EPA's regulatory agenda.

The issue of paying for firm natural gas transmission service to avoid curtailments for electric generation is unsettled and an area of marked disagreement between pipelines and utilities. If natural gas-based electric generators were to be required to hold firm transportation service to assure not being curtailed, electric costs would increase and, in some areas, a lack of firm transmission capacity would significantly alter the availability of standby generation.

Here we come to a critical point: *Multiple factors drive utility investment decisions. Fuel diversity to spread delivery and price risk, access to resources such as cooling water or gas pipeline capacity, access to electric transmission line capacity to export the power to load centers and many other factors dictate the appropriate investment for each utility. In the context of these decisions there is increasing concern that EPA rules are prohibiting the consideration of coal as a baseload electric generation resource. In essence, through ever-tightening controls, EPA is taking critical fuel choice decisions away from the private sector and in doing so has begun to dictate federal energy policy without a robust debate, mandate or authorization from Congress.*

Regulatory Risks from EPA's Fossil Fuel Regulations

With its regulatory agenda, EPA has established a number of dangerous precedents that will result in unwarranted and unsettling intrusions into markets and private sector decision-making. EPA has failed to follow established administrative procedures by shortening the time for analysis, review and comment on proposed rules. This reduced timeline, along with unprecedented changes to the established regulatory framework and short timelines for compliance may strand investments for some relatively new, cleaner and more efficient power plants. These plants would provide important baseload electric capacity to serve the nation's energy consumers.

Coal Plant Retirements and Disparate Regional Impacts

Coal-fired power plants are not evenly distributed throughout the U.S., and recently utility companies have announced an unusually high number of coal plant retirements. The closures are due primarily to EPA regulations targeting coal plants as well as to the low cost and availability of natural gas. In addition to these announced closings, a large number of coal plants will experience outages while they retrofit with environmental control equipment required to achieve compliance. These closings and temporary shutdowns will result in disproportionate impacts on those areas of the country where coal-fired power is predominant.

A number of government and private sector entities have provided estimates of the actual extent of these coal plant closures. These estimates are not easy to compare since some provide estimates based on a range of megawatt capacity, others provide median numbers, while still others estimate the percentage of capacity that will be shut down. Some EPA rules are final and some are proposed. Not all analysts look at the same universe of rules when providing estimates. Some estimates made in early 2012 do not take into account changes that EPA is making to the EGU MATS rule or new initiatives the Agency may undertake since the Cross State Air Pollution Rule (CSAPR) was vacated by the U.S. Appeals Court in August 2012.

ANALYSIS OF PLANT CLOSURE ESTIMATES RESULTING FROM EPA REGULATIONS

EPA	**17.5 GW**	December 2011
EIA	**49 GW**	July 2012
Credit Suisse	**60 GW**	September 2010
ICF International	**75 GW**	October 2010
NERC	**36.4 GW**	October 2010
The Brattle Group	**57.5 GW**	December 2010
ICF/EEI	**71.5 GW**	January 2011
FBR Capital Markets	**37.5 GW**	March 2011
FERC	**60.5 GW**	August 2011
NERA Economic Cons.	**48 GW**	September 2011
The McIlvain' Company	**50 GW**	March 2012
Bloomberg Finance	**55 GW**	June 2012
The Brattle Group	**68 GW**	October 2012

Still, there are, a substantial number of expert entities that have provided coal plant closure estimates. What has become apparent is that EPA's estimates are an outlier compared with both government and private sector estimates. EPA's model estimates that the Utility MATS rules would cause the retirement of 4.7 GW of coal capacity, while the Cross State Air Pollution Rule (CSAPR) would drive 4.8 GW of capacity into retirement. But according to the National Mining Association, by May 2012, even with the CSAPR stayed then in the courts, 25.1 GW of capacity had officially announced retirement and more were expected.

In June 2012, the U.S. Department of Energy's Energy Information Administration (EIA) estimated that 49 GW would be shut down, most of it over the following five years, with coal's share of power production declining from 48 percent in 2008 to 38 percent by 2035. At the same time, EIA indicated that as little as 34 GW might be retired but as much as 70 GW could close down.

The North American Electric Reliability Corporation (NERC) updated its estimate on plant closures in November 2012, raising the estimate to 71 GW shuttering in the next decade, with most of the closures occurring within five years. NERC believes this raises issues of system stability and the need for transmission enhancements. NERC anticipates the possibility of as much as 100 GW of natural gas capacity additions over the next decade, which could increase the chances of curtailments and interruptions due to the electric sector's lack of firm transmission service.

Bloomberg recently put together a comparison chart of various estimates of plant closures. They chose a median number for those who provided a range; noted that several of the estimates included possible closures due to the expected impact of the cooling water and coal ash regulations; and noted that the ICF/EEI estimate included an assumed $25 per ton fee on carbon dioxide – all items that were not included in EPA's estimates. Nevertheless, as can be seen in the comparative chart above, the extent to which EPA is an outlier is clear. Overall, Bloomberg shows that analysts put coal-fired electric capacity declines at 12-24 percent due to fuel competition and EPA regulations while EPA estimates only 6 percent retirement.

EPA has never conducted a cumulative economic impact analysis, including job losses, for all of the recently proposed rules in order to better inform Congress and the public on the full impact of these rules on employment and the economy.

The Brattle Group updated its estimates of coal plant closures in October 2012. They expected a higher number of retirements in the range of 59-77 GW to close by 2016. The higher number is attributed to lower demand and continued lower natural gas prices.

Of course, all of these figures are provided on a national impact basis, which can disguise the disparate and sizable regional impacts. According to the General Accounting Office (GAO), in 2010, 10 states depended on coal for over 70 percent of their power plant generation; 11 states were 50-70 percent dependent; 14 states were 20-50 percent dependent; with 15 states having 0-20 percent coal generation. The five states where coal plants are expected to experience the largest closures are Ohio, Pennsylvania, West Virginia, Virginia and North Carolina. The Midwest and Southern regions are expected to be hit hard by these changes. **EPA's dollar impact numbers fail to capture how much more onerous its regulations will be in highly coal dependent regions.** Further, the more detailed the analysis, the clearer it becomes that some areas of the country will disproportionately bear the brunt of the costs of the EPA rules.

Regulating Without Understanding the Impacts on Jobs

Section 321 of the Clean Air Act (CAA) requires EPA to provide continuous evaluation of potential loss or shifts in employment due to its regulations. Unfortunately, while EPA has provided estimates of plant closures, it has failed to provide an analysis of the net job losses from their proposals.

For example, in the Utility MATS Rule, EPA asserted, "we do not have sufficient information to quantify other associated job effects associated with this rule." However, EPA was able to estimate the short-term employment opportunities created by increased demand for pollution control equipment, suggesting that the proposed rule could support a net of roughly 31,000 job-years.

Others organizations have made job loss projections. NERA Economic Consulting projected that just four of the many proposed rules would result in an average net job loss of 183,000 jobs per year and a cumulative net job-year loss of 1.65 million through 2020.[13]

Factors That Will Drive Up Costs and Threaten Electric Reliability

While EPA has provided some flexibility as to the time frame for compliance with the MATS rule,[14] many experts believe that inadequate time to come into compliance will contribute significantly to the high costs of this and other rules. In "sue and settle" cases, where EPA has made court-sanctioned agreements with environmentalists to set schedules for rules, the timeline for proposing and issuing final rules have been unreasonable. In many cases, EPA has been unable to keep to the court-agreed timelines that it set for itself. The compressed compliance period means many utilities will be chasing the same engineering resources, capital, equipment and labor at the same time, unnecessarily driving up costs. Utilities that cannot meet these deadlines could be subjected to significant financial penalties under the Clean Air Act (CAA). Even if EPA chooses not to exercise enforcement and impose penalties, utilities are still subject to third party citizen suits from environmental groups.

The American Public Power Association (APPA) filed comments stating that 90 to 99 percent of those members that responded to the APPA survey would need at least 77 months to comply, given the need

[13] NERA Economic Consulting, *Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations*, prepared for American Coalition for Clean Coal Electricity, September 2011, p. E-5,

[14] EPA has declared it will make "broadly available" a 1 year extension of the 3 year compliance period allowed by statute. See Congressional Testimony of the Hon. Gina McCarthy, Assistant Administrator, USEPA, before the House Energy and Commerce Committee, 2/8/2012, p.6.

to plan for, finance and conduct an extensive public comment process, as well as multiple years to budget, finance, bid, construct and install the necessary equipment to comply with the rule. The lack of adequate time for compliance led APPA to file suit in federal court to prevent the rule from forcing public power utilities into noncompliance, the first time the association has had to resort to such measures.

Additive Impacts

EPA's typical process is to evaluate the impacts of each new regulation individually rather than analyzing the additive impact of each regulation. While one regulation individually may have no significant impact, between January 2009 and October 2012, EPA had already issued 45 regulations deemed controversial, according to the Congressional Research Service.[15] This series of regulations has a substantive cumulative impact. EPA has ignored the requests of other agencies, state regulatory commissions and industry to conduct a cumulative impact analysis on the effect of such a large number of regulations being issued in such a short amount of time.

Impact on Electric Reliability

EPA asserted that its rules would not negatively impact electric grid reliability, but the agency has not conducted an analysis of the impact on the grid, and many of the plants that will be retired or retrofitted due to EPA rules are located in important grid transmission areas that provide key voltage support. EPA also failed to do a cumulative impact analysis of its many recent rules affecting utilities despite repeated suggestions to do so.

EPA further failed to take into account transmission-related issues when providing analysis of the impact of its utility-related rules or consider the ability of FERC or other government decision-makers to approve needed upgrades in the truncated time frames. FERC Commissioner Phil Moeller has suggested that FERC may be unable to make required approvals for plant retirements or retrofits within EPA's timeline. Moeller stated that those problems illustrate "why the Federal Power Act and our longstanding policies implementing that act were never designed to accommodate the time limitations that have been imposed by EPA upon the owners of coal plants."

EPA has asserted that fuel switching of existing EGUs to natural gas and construction of new gas-fired generating units can replace the retired coal units within the rule's time frame. However, many experts point out that planning, contracting, permitting, financing and construction will take longer than the permitted three-year time period with an assumed additional year granted by the states. Not all units will have access to natural gas or are located near pipelines or other required gas infrastructure. Relocating plants in order to access gas pipelines may also require transmission upgrades, something not considered by EPA. Transmission lines are built to baseload plants and if replacement natural gas

[15] Congressional Research Service, *EPA Regulations: Too Much, Too Little, or On Track*? James McCarthy, Oct. 5, 2012.

plants must be relocated closer to natural gas infrastructure, new transmission lines may be required. EPA's own permitting rules present a time-consuming obstacle, yet EPA's rules don't allow for accelerated permitting for pollution controls or exemptions from New Source Review (NSR) requirements considered for making pollution control upgrades.

EPA conducted resource adequacy assessments, rule by rule, looking at whether retirements would cause reserves to fall below regional requirements, but this does not equate to an assessment of grid reliability. FERC Chairman Jon Wellinghoff testified in September 2011 before the House Energy and Power Subcommittee that the type of analyses conducted by EPA is "irrelevant" to determining grid reliability. **To date, no government entity has undertaken an assessment of the impact of EPA's full regulatory agenda on grid reliability.**

Consumer Rate Increases

There is no question that EPA regulations will drive rate increases through the required addition of pollution control equipment, the need to replace plants that cannot meet the new standards, and through continuing uncertainty as to future potential EPA regulations.

While the costs of additional environmental controls are substantial, the compressed timeline for implementation of the EGU MATS rule is a major driver of higher costs, as numerous utilities must compete for limited engineering resources in a four-year time frame. According to the Electric Power Research Institute (EPRI), **greater flexibility in EPA's current rulemaking could save the U.S. $100 billion in present value terms between 2010 and 2035**.

In its October 2012 report, *The Value of Innovation in Environmental Controls,* EPRI examined the cumulative costs of just three of the many EPA rules: the EGU MATS, 316(b) and CCR rules. If EPA were to provide a compliance timetable that was more flexible and provide more compliance options, the overall costs to the U.S. economy could be lowered by $100 billion.

Additionally, EPA has ignored or else lacks the requisite expertise to analyze and take into account the additional costs that are generated by its own regulatory agenda, which requires replacement of generation or installation of controls in a relatively short period of time. APPA commissioned an in-depth study in 2010, called *Implications of Greater Reliance on Natural Gas for Electricity Generation,* that outlines many of the infrastructure requirements that EPA and other federal agencies have failed to address, including the need for additional natural gas pipeline and storage capacity and transmission investment. These costs have not been analyzed in any of the government economic impact analyses undertaken to date.

The federal government has not provided a national analysis that identifies which plants are closing and whether there is sufficient pipeline capacity serving those affected areas to provide needed supplies of natural gas for replacement plants. A number of pipelines have already indicated that they do not have sufficient capacity to serve existing markets, let alone those markets where new gas plants will be constructed.

The Role of Fuel Diversity in Electric Reliability and Costs

EPA's proposed GHG NSPS, which requires all new EGU fossil-fueled plants to meet a natural gas combined cycle (NGCC) standard, ignores important national goals such as fuel diversity, electricity affordability and reliability, economic growth, jobs and national energy security. CAA Section 111 requires EPA to take into account energy requirements in setting NSPS, but there is no evidence that

Lessons Learned, a Case Study

Jacksonville, Florida's JEA, a municipal utility serving more than 400,000 electric customers in 2013, has pursued a diversified mix of fuels and purchase power contracts after learning a difficult lesson. In the 1970s, JEA's entire generating fleet had been powered by residual oil, a byproduct of refined crude oil. During the oil crisis JEA's fuel costs jumped over 400 percent in two years and corresponding consumer electric prices rose dramatically. JEA was singled out for having the highest electric rates in Florida. The move to prevent future price shocks through diversifying generating capacity took time accomplish given long planning, design and construction time. The utility also diversified its fuel delivery options over time to include rail, ocean vessel and pipeline and began the use of long-term fuel contracts and hedging. While JEA, like the rest of the country, now obtains a substantial percentage of its generating capacity from natural gas, it has not lost sight of the fact that natural gas prices have fluctuated almost 500% over the past five years and maintains diverse generation resources should gas prices rise again.

EPA has done so. Congress has consistently considered fuel diversity and energy security important factors for assuring economic growth. Certainly, Congress never meant for EPA to use Section 111 as a means for eliminating an entire industry – namely, the coal industry – from the national economy.

An example of this Congressional intent was the Fuel Use Act of 1977. Following the natural gas supply disruptions in 1976-77, Congress passed this bill which ruled out using highly price volatile (at the time) natural gas and oil for new electric generation. This act led to widespread construction of new coal units to provide for more secure, abundant and cost-effective domestic sources of electric generation.

The 2012-2020 eight-year economic assessment (based on 2012 gas prices and availability) that EPA uses to support its GHG NSPS proposal for new utility plants fails to take into account the long-term economic detriment that would result from taking coal out of the country's fuel mix. EPA provided no economic analysis to support the notion that natural gas can replace coal's role in electricity supply without causing major disruptions to electric rates, reliability, economic growth, jobs and natural gas prices. EPA's proposed rule introduces an unacceptable level of systemic risk that could lead to electric disruptions.

The U.S. Congress has long pursued a national policy that promotes fuel diversity in order to provide lower electric rates and to help assure national energy security. Disproportionately greater dependence on one fuel that has shown significant price and supply volatility can have very substantial negative economic consequences. The U.S. has the largest coal reserves in the world, comprising a secure domestic source of energy. That fact alone argues against taking coal out of the fuel mix. Perhaps more important, diversity of fuel sources provides lower, more predictable electric rates, which promotes national economic and job growth.

In the proposed rule's GHG NSPS Preamble, EPA refers to the President Obama's goal of having 80% of energy supplies from clean sources by 2035 and states that the proposed NSPS for new utility plants will help to achieve that goal.[16] But looking at the realities faced by utilities, it's clear that the president's goal may be completely unrealistic and unachievable. It would be unwise to use this goal as a basis for regulation under the CAA. It's worth noting that Congress has consistently refused to pass a renewable energy standard, "clean energy standard," or GHG limitation bill. EPA should consider that such a goal could not be met without requiring an infeasible technology, carbon capture and sequestration (CCS), for both coal and natural gas. Finally, this goal forecloses any national standard based upon "all of the above," which is the declared energy strategy of the president.

Electric disruptions are usually tied to weather related events, such as a hurricane in the natural gas producing Gulf of Mexico, sudden and severe winter cold snaps, or summer heat waves. There is great value in the ability to store several months of coal supply on-site, which allows for the use of the stored coal for peak generation during weather related emergencies. EPA has argued that utilities are retiring coal plants solely due to the availability of abundant, low-priced natural gas, but the facts do not support this assertion. As Peter Glaser of Troutman Saunders testified before the House Government and Oversight Committee on May 31, 2012:

> "This conclusion is implausible. Currently, low natural gas prices would only incent these [coal] units to run less or to be placed on stand-by, not to retire. Prudent utilities would keep these units available against the likelihood that gas prices, which have proven to be very volatile in the past, will increase again in the future. What is forcing these units to retire permanently is that they cannot meet EPA's MATS, CSAPR and impending additional standards without investing hundreds of millions of dollars of pollution control equipment."

The ability to continue to maintain and run pollution-controlled coal plants as backup power sources without the threat of regulatory and legal penalties is important to the nation's energy reliability. But without assurances, utilities cannot afford to risk the costs associated with keeping coal generation as reserve capacity.

[16] 77 Fed. Reg. at 22396, referring to President's "Blueprint for a Secure Energy Future", March 30, 2011.

In commenting to FERC on its solicitation for information on the coordination of the natural gas and electric markets as electric gas generation increases in February 2012, Thomas Schroeder of Nebraska Public Power District (NPPD) provided perspective on coal's value as a reliable backup fuel. He stated,

> "If the amount of electrical generation from natural gas-fired electrical generation facilities was constant (i.e., base-load units that do not vary load), then supplying the natural gas would be relatively straightforward. Unfortunately, the demand for electricity varies throughout a day and America's coal-fired … facilities are used to 'follow' that load. This includes the unexpected loss of a neighboring electrical generating unit and the significant changes in demand that occur when Mother Nature decides the wind will stop or start blowing … or how cold/hot the temperature will actually be. If the electrical load is higher than estimated, coal-fired units can push coal off of their stockpiles and increase generation. If natural gas-fired electric generation facilities are to replace coal, then they will also have to follow this same load. The problem is that a natural gas fired electrical generation facility is limited by the natural gas pipeline on how much natural gas they can use (not nearly as flexible as coal on a daily basis). …natural gas pipelines demand that their customers nominate how much natural gas they intend to use (typically at least 21 hours prior to the natural gas actually flowing) and then they expect their customers to actually use that amount of natural gas … If they don't, then the natural gas pipeline can penalize that customer …"
>
> "Some natural gas pipelines offer service to help customers balance their nomination to their actual burn. However, on days where demand for gas on these pipelines is high, the pipelines will not allow for the use of these balancing services (or at the very least, limit their use). If more natural gas is used to replace coal … then one would expect the number of days each year where the demand for natural gas is greater than in the past will increase, thus increasing the number of days where a customer will be limited on balancing their supply of natural gas …"
>
> "Next, it should be understood that several of the major natural gas pipelines do not offer any balancing services (they expect their customers to take the same amount of natural gas each hour of the gas day). [This is] not a good fit if natural gas-fired electrical generation pipelines do not have much excess transportation or storage capacity to serve new customers."[17]

This is only one example of the many issues that exist when replacing coal with natural gas and one of many that EPA and other government agencies have not addressed sufficiently in order to assure electric reliability.

[17] Submittal 2010220-4000, February 20, 2012,
Docket # AD12-12-000

Recommendations

U.S. economic activity is directly related to electricity affordability and availability, and its continued abundance will be critical to future economic growth. Maintaining affordable and reliable power requires efficient government policies, diverse fuel options and reasonable long-term investment horizons. Unfortunately, federal government policies both in place today and under development are injecting significant uncertainty into utility operations, increasing costs and threatening reliability. To address these concerns the following steps should be taken:

- **Incentivize Technology Development -** It is in the nation's best interest to develop policies that maximize development of all fossil resources while minimizing ancillary negative impacts. Instead of forcing change through regulatory policy that relies on unproven or cost prohibitive technologies, such as the EPA's proposed NSPS for GHG for new units, the government should increase research and development to prove technologies that are affordable and deployable to meet environmental goals for all fossil fuels. Once proven technologies exist, the government can facilitate a smoother transition toward better resource consumption in a manner that minimizes economic disruption.

- **Long Term Integrated Energy Planning -** The U.S. Government has multiple agencies governing electric policy but each operates independently. These agencies should be tasked with developing an integrated electricity plan that accounts for the long-term policy goals of increasing energy independence; providing for reliable electric energy; maintaining a cost advantage over major international trading partners; and recognizing the need for fuel diversity while at the same time providing a path toward a cleaner resource mix. Any clean energy resource mix should include broad choices that are regionally achievable including hydropower, clean coal, biomass and nuclear, as well as traditional renewables.

- **Coordination of Major Regulatory Programs -** The legal framework governing electric generation has developed from Congressional, Judicial and Executive branch actions that date back nearly 100 years. But today, the disjointed nature of the various federal agency actions, the lack of integration between laws governing utility operations and the imposition of court decisions have resulted in a highly inefficient and, at times, conflicting operating environment. It is time for a better process. The government should begin to coordinate major regulatory actions in order to meet the integrated needs of the electric grid and promote a more predictable and efficient path forward.

- **Prudence in Regulatory Policy -** Long-term energy policy requires rational regulation to provide for reasonable investment certainty. Regulations that have no benefits, cannot be met or jeopardize the reliability of the electric grid serve to not only increase business uncertainty but also undermine the confidence in the regulatory process and the regulator itself. So too, regulations that fail to withstand legal scrutiny only increase regulatory risk. Simply put, the regulatory process appears broken. Regulators and policymakers must take steps to address this problem.

- **Reliability and Integration Assessment -** The U.S. government agencies that regulate the electric power industry should conduct a thorough assessment of what plants are closing and in what time frame, where those plants are located, and whether or not those plants or the region are adequately served by natural gas pipelines and other required infrastructure that can adequately accommodate growing demand for natural gas.

CONCLUSION

Electric power supply has reached a level of consistency that the vast majority of Americans appropriately take for granted. They know little about the details of how it is generated and delivered and only realize its importance in those periods when it is not available. This consumer reliance is a testament to the success of the modern electric grid. Policymakers must recognize that continued success will require government policies that are rational, predictable and prudent, and they should take steps to affirm that future policies meet that standard.

APPENDIX: A DETAILED DISCUSSION OF THREE MAJOR EPA RULES IMPACTING THE ELECTRIC UTILITY SECTOR

EPA has embarked upon an aggressive regulatory agenda for electric utilities. EPA and the States are only in the early stages of substantively implementing the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and the 2010 SO_2 and NO_2 NAAQS. A January 2013 court decision found that EPA was incorrectly implementing the 1997 and 2006 PM NAAQS – and the more stringent method required by the court decision will impact the forthcoming 2012 PM NAAQS implementation process as well. The proposed Natural Gas Turbine NSPS rule as proposed is an unfortunate precedent for industrial manufacturers due to substantial changes to the scope of what constitutes reconstruction of an existing unit that would trigger NSPS.

A number of these rules, such as the CCR and 316(b) rules for cooling water intake, have been proposed, are undergoing review and not yet final. It is believed that both of these rules are being modified in a manner that will that make them less onerous than as originally proposed. However, should EPA choose the more stringent options it proposed, these two rules would have a very large and negative impact on the continued viability of a number of existing coal plants. Three rules have been particularly troublesome:

1. CSAPR

The CSAPR rule was vacated by a three judge panel of the United States Court of Appeals for the District of Columbia Circuit, and an appeal by EPA was denied en banc. It is worth noting of several aspects of this rule whereby EPA sought to establish new and negative trends for coal utilization. The purpose of CSAPR was to eliminate upwind pollution sources "from emitting any air pollutant in an amount which will…contribute significantly to nonattainment in, or interfere with maintenance by, any other state." EPA's CSAPR replacement for the Clean Air Interstate Rule (CAIR) was a very substantial departure in ways not required by the courts.

- EPA's final CSAPR usurped the traditional state role in designing appropriate compliance plans known as State Implementation Plans (SIPs). This is particularly important because states are better suited to understanding state-specific circumstances and are highly motivated to develop the lowest cost implementation plans. EPA's imposition of a truncated timeline led them to impose Federal Implementation Plans (FIPs) but there was no court ordered or NAAQS deadline that compelled this short timeline. EPA assumed the right and responsibility to determine *how* a state's emission reductions should be accomplished. The imposition of FIPs violated the "cooperative federalism" that is the fundamental architecture of the CAA.

- EPA selected a new methodology for determining what constitutes a significant interstate impact, lowering the significance level to 1% of the NAAQS. This methodology would have reduced automatically the significance level with each future ozone and PM NAAQS revision without any consideration of whether that decrease is scientifically justified.

- EPA's proposed allowance allocation scheme would disadvantage those utilities that had made significant investments to comply with CAIR and other rules compared with those utilities that did not, effectively punishing those utilities that had made early compliance investments and aggressive emission reductions.

- EPA chose non-representative baseline years of 2008 and 2009 for SO_2 and NOx emissions. In this time frame, many units had extended outages to install SO_2 and NOx control equipment; the U.S. economy plunged into economic "crisis;" and electric demand dropped significantly.

- EPA failed to fully account for post-2005 emission reductions in their modeling, ignoring substantial SO_2 and NOx emission reductions made in response to CAIR.

- EPA made major changes from the proposed rule when it issued the final rule, without providing prior notice allowing the opportunity for public comment.

- EPA failed to justify its stated assumption that pollution control projects would not trigger GHG PSD requirements and optimistically assumes that plant retrofits and fuel changes could be accomplished in a short time period.

The D.C. District Court of Appeals vacated the rule and remanded it to EPA based on two key findings. First, EPA exceeded its authority in setting "significant contribution", imposing very large reductions that were based on the cost of reductions and not on the precise upstate contribution. The court stated "the statute is not a blank check for EPA to address interstate pollution on a regional basis without regard to an individual upwind State's actual contribution to downwind air quality." Second, the court found that EPA is not permitted to impose FIPs before the states have been afforded the opportunity to devise their own SIPs.

2. Proposed GHG NSPS for New EGUs

In addition to the many legal, technical and policy problems with this proposed rule, EPA cannot identify any direct CO_2 related benefits (health or otherwise) and concedes the rule would not result in a decrease in CO_2 emissions. Allowing a rule so lacking in justification to proceed is unprecedented, with unknown and potentially huge consequences. AFFORD commented on this rule.[18]

New Coal Plants Cannot Achieve the NSPS Standard. EPA's proposal to combine all fossil fuel-fired baseload and intermediate units into one source category, with a few exceptions, and to require a single standard for this category that can only be achieved by the lowest emitting fuel, natural gas, using one

[18] http://www.regulations.gov/#!docketBrowser;rpp=25;po=0;dct=PS;D=EPA-HQ-OAR-2011-0660

electricity generating technology, combined cycle, is unprecedented and an imprudent departure from past practice and policy. This rule effectively bans new coal plants. Contrary to past policy, EPA is "re-defining the source" in an impermissible manner that makes EPA regulation the determinant in future fuel and generating technology choices rather than the private sector and markets. This will serve as an unfortunate precedent for other industrial categories.

The proposed standard is based on a particular generation technology and a fuel and not on a "best system of emissions reduction." While EPA has in the past issued several "fuel neutral" standards, those standards have always been based on the ability of *each* fuel to meet the standard. In this case, EPA issued a proposed standard that is based on and can only be met by a single technology (combined cycle) using a single fuel (natural gas). Electricity generating technologies and fuels that would be regulated under the proposed single standard are substantially different and cannot be combined into one category without "re-defining the source."

Different generation and fuel combustion technologies cannot utilize the same control options and cannot meet the same emission rates. Fuel decisions are not emission reduction technologies and the "best system of emission reduction" (BSER) for natural gas, oil, and coal are markedly different. EPA states that it can create this new category, in effect "re-defining the source," because all the units, regardless of fuel, "perform the same essential function," of providing baseload or intermediate generation.[19] If this is the case, then there is nothing to keep EPA, at some point in the future, from requiring that all new units be non-CO_2 emitting units such as nuclear or most renewable generation. Consistent with the requirements of Section 111(b)(2) of the CAA, EPA has had in place a long-standing record of correctly setting NSPS standards that distinguish amongst plant designs based on classes, types, sizes and fuels by establishing emission limiting standards for subcategories of generators. The proposed single standard unlawfully and irrationally requires new coal-fired boilers to meet the emission rate of some new NGCC plants and, in effect, impermissibly bans construction of new coal plants for the foreseeable future.

EPA's proposed standard of 1,000 pounds of CO_2 per gross megawatt hour (1,000 lb CO_2/MWh) cannot consistently be met by many existing natural gas combined cycle (NGCC) units and does not take into account a number of very important operational factors, including the necessity of using higher CO_2 emitting alternative fuels (e.g. distillate oil) when natural gas is curtailed or supplies are disrupted during emergencies such as hurricanes.

EPA clearly acknowledged in February 2012 that basing the NSPS for conventional pollutants on natural gas would prevent the construction of new coal plants and consequently is impermissible. EPA stated:

> *Basing the amended standards on the use of natural gas would preclude the development of new coal-fired EGUs since the standards would not be technically achievable, even with the*

[19] 77 Fed Reg at 22410

application of IGCC technology...Therefore, basing the NSPS on [natural gas] emissions would not be achievable for coal-fired EGUs with any technology that EPA is aware of. [20]

EPA's "alternative compliance option" for future coal plants – requiring CCS and a 30-year averaging period to meet the proposed standard – is unworkable and no lending institution would ever provide financing. CCS technology is not commercially available or affordable and the requisite legal and regulatory framework to permit its use is not in place. There is widespread agreement that EPA's GHG NSPS for power plants rule, as proposed, will prevent the construction of new coal plants and halt development of new, clean coal technologies. EPA's own analysis concedes that CCS is unaffordable and would add 80% to the cost of a pulverized coal plant.

It is particularly worrisome that EPA's proposed rule has left unanswered important questions concerning the impact of the rule on existing plants that are modified or reconstructed. EPA concedes that the current exemption from "modification" rules for pollution control projects triggering NSPS is legally vulnerable. While the Administrator declared that the standard "would never apply to existing plants," the courts will make that decision, not the Administrator. If "new" unit NSPS for GHGs were to be applied to "modified" existing units, the results could be chaotic and damaging.

Since EPA determined that there would be no quantifiable costs nor benefits associated with the GHG NSPS rule, the Agency did not perform the extensive economic analysis normally found in the requisite regulatory impact analysis (RIA) or provide the relevant economic information required for public comment for its proposed GHG NSPS for new plants. Rather, the Agency relied on qualitative assessments.[21]

EPA's single-minded environmental and related green energy focus fails to take into account the real world impacts of its actions. EPA has based its proposed standard on the false assumption that low-cost natural gas is available throughout the continental United States. EPA's proposal ignores important national goals, including fuel diversity, electricity affordability and reliability, economic growth, jobs and national energy security. EPA's aggressive coal-related regulatory agenda could add systemic risk that threatens electricity supply and potential blackouts and far higher consumer electric rates.

EPA argues in its Regulatory Impact Assessment (RIA) that this rule would not be "economically significant." AFFORD would argue that this will be among the most economically significant rules EPA has ever proposed. With the proposed rule, EPA, in effect, bans new coal plants, and in doing so takes a

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[20] EPA Response to Public Comments on Rule Amendments to Standards of Performance for Fossil-Fuel-Fired Steam Generating Units for Which Construction is Commenced After August 17, 1971, Dec. 2011, 2.2

[21] In the GHG NSPS RIA EPA states "In the unlikely event that market conditions change sufficiently to make the construction of new conventional coal-fired units economical from the perspective of private investors, the level of avoided negative health and environmental effects expected would imply net social benefits from this proposed rule."

proven, affordable, stable and abundant electric generating resource off the table without adequate evaluation of the availability and costs of replacement generation. The EIA, in their June 25, 2012 Annual Energy Outlook, warns that GHG controls could pose a greater threat of coal plant retirements than EPA's other recent rules targeting air toxics and criteria pollutants and that uncertainty over future GHG regulation will have a negative impact on investing in existing coal plants. In doing so, EPA introduces new levels of risk into the electric generation system that threaten costly future interruptions and potential rolling blackouts in certain regions of the country.

If EPA can set a NSPS standard that cannot be met by new coal plants, what is to prevent EPA from ultimately setting a NSPS standard that cannot be met by new natural gas plants, or setting NSPS guidelines (that are regulations) for existing plants that cannot be met by coal or gas plants?

There is no seeming end to where this far-reaching policy change can take the nation. Whatever regulatory framework EPA develops to address utilities can be used as a template in the future for manufacturing.

3. EGU MACT

In establishing the need to regulate utility air toxics, EPA failed to establish the necessary requirements to regulate hazardous air pollutants (HAPs) under Section 112 of the CAA and failed to accurately account for the costs and benefits of the regulation. In commenting on the application of MACT standards when drafting the CAA Amendments of 1990, the House Energy and Commerce Committee stated "MACT is not intended to require unsafe control measures or to drive sources to the brink of shutdown."[22] Yet this is exactly what the rule will accomplish: shuttering plants, potentially impairing electric reliability and increasing electric energy costs for minimal HAP emissions reduction benefit. AFFORD commented on this rule[23].

In December 2000, EPA Administrator Carol Browner made a finding that there was a "plausible link" between anthropogenic mercury emissions and mercury in fish, but EPA did not quantify the risk in the six-page decision. The public was denied the opportunity to provide comment on this major decision. Industry was not able to challenge the original listing immediately after it was issued because the D.C. Court of Appeals in 2001 ruled that the CAA requires final action before appeals can be heard.

The 2000 Finding was deficient in that:

[22] Report of the Energy and Commerce Committee on Clean Air Act Amendments of 1990, 101-490 Part 1, P. 328. May 17, 1990
[23] http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2009-0234-18500

- EPA did not make a finding that mercury emissions were causing health problems. Rather, EPA Administrator Browner only found a “plausible link” between EGU mercury emissions and mercury levels in fish.
- EPA did not make any finding concerning hazards to public health from non-mercury and non-nickel HAPS (metallic HAPs, acid gases and dioxin emissions).
- EPA ignored the Congressional directive to develop and describe alternative strategies for regulation in addition to MACT.
- EPA based its 2000 scientific finding on the 1998 report to Congress but the report found that the scientific uncertainty was too great to justify regulation.

In 2005, the Bush Administration EPA revised its 2000 Regulatory Finding, stating that it lacked “foundation,” determining that Administrator Browner “lacked basis” for the listing since EGU emissions did “not pose hazards to public health.”

In 2008, the D.C. District Court of Appeals struck down EPA’s 2005 delisting method as contrary to the CAA, requiring EPA to go through the precise delisting procedures set out in the CAA under Section 112(c)(9).

In May 2011 the Obama Administration EPA proposed a MACT rule for utilities that would be one of the most expensive rules every proposed by EPA, while generating very small direct health benefits associated with reducing mercury and other HAP emissions. There are a number of concerns regarding this proposal:

- EPA stated that it cannot quantify the benefits of regulating non-mercury HAPs yet it has proposed to regulate them at great cost anyway. EPA does not provide new studies that justify regulation of non-mercury HAPs or that would change the Agency’s 2005 determination that EPA’s 2000 Finding “could not have reasonably concluded that coal-fired utility unit non-mercury HAP emissions presented a hazard to public health.”
- By EPA’s own calculations, 97% of the health benefits come from particulate matter reductions, which are considered a co-benefit, and the prevention of 11,000 premature deaths a year.[24] At a 3% discount rate, EPA claims $37 to $90 billion in total monetized benefits against $9.6 billion in costs a year.
- It is inappropriate for EPA to justify the benefits of the rule almost entirely on health co-benefits from controlling emissions for which EPA already has established a health standard and which the CAA addresses through separate and distinct legal mechanisms that will afford lower electric rates and greater flexibility for industry. EPA has already calculated and accounted for the benefits of Particulate Matter (PM) reductions to justify $PM_{2..5}$ NAAQS. How can EPA’s NAAQS standard be “protective of public health” while still allowing 11,000 premature deaths a year? That EPA would claim almost $36-89 billion a year in PM2.5 health co-benefits from the EGU MACT rule for the modest reductions in mercury and non-mercury HAPs is not credible.

[24] Based on the EPA summary of benefits table in the Utility MACT proposed (versus final) rule preamble, $PM_{2.5}$ related co-benefits range from $53 billion to $140 billion while mercury related benefits range from $0.45 to $5.9 million. While EPA admits that CO_2 reduction benefits may be $570 million, the RIA for the Utility MACT indicates that this number is highly suspect. If a CO2 benefit is excluded, $PM_{2.5}$ reductions accounts for 99.993% to 99.999% of the benefit of the Utility MACT rule.

EPA attributes no monetized benefits from reduction of acid gases and non-mercury metals and very modest benefits from mercury reductions yet asserts significant benefits from the proposed rule. EPA officials assert that benefits from reducing the non-mercury HAPs gases *could* be identified, but they have not done the studies since, according to statements made by EPA staff, the greater focus of their studies has been on criteria pollutants. The result is that EPA has calculated that virtually all the benefits from inflexible and costly regulation under MACT standards will come from the co-benefits associated with $PM_{2..5}$ reductions that are more appropriately addressed through the many other PM regulatory programs that have far greater cost efficiencies and more flexible compliance timelines provided by Congress.

Mercury and nickel were the only Haps where EPA found it “appropriate and necessary” to regulate in the 2000 Finding and in May 2011, EPA conceded that it cannot quantify any benefits from non-mercury Haps regulation. Further, EPA chose not to avail itself of the far less costly approach afforded to it to address non-mercury HAPS through health-based limits. EPA believes it is required by the statute and court case precedents to regulate all HAPs if it makes a public health finding for any single HAP. This interpretation ignores that Congress set out a completely separate and different process for utilities under Section 112(n)(1)(A) that diverges from the rest of industry.