UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference	Docket No. AD12-1-000
North American Electric Reliability Corporation	Docket No. RC11-6-000
Public Service Commission of South Carolina and the South Carolina Office of Regulatory Staff	Docket No. EL11-62-000
	(Not Consolidated)

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Introduction

I appreciate the opportunity to testify today about the tools and processes that are available to assure that neither EPA's Cross-State Air Pollution Rule ("CSAPR") nor its proposed Mercury and Air Toxics Rule ("Toxics Rule") will adversely affect reliability. CSAPR affects emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from fossil-fuel power plants in the Eastern half of the U.S.; and the Toxics Rule creates the first ever national limits on power plant air emissions of hazardous pollutants, such as mercury, hydrochloric and sulfuric acids, arsenic and other toxic metals. These rules replace two previous attempts to implement the Clean Air Act ("CAA") that were sent back to EPA by federal courts. The electric industry has known about these rules for many years; what it needs now is for the rules to be finalized so it will have the certainty needed to begin implementation. By providing regulatory certainty, the rules will be the driving force to modernize and improve the efficiency of our aging electric system so that Americans can continue to have a safe and reliable electric system to support our nation's economic growth.

These rules do not require a choice between public health and reliability. Often, opponents of EPA's air rules contend that EPA is directing the shutdown of most or all of the Nation's coal fleet. To the contrary, there are a number of ways to comply with the impending regulations, from purchasing allowances (in some cases), to retrofitting with well-established pollution control technology, to switching fuels, to derating a unit. As I believe it is critical to understand how the rules work and what is required to comply before assessing their impacts, I include background information about the rules, a summary of compliance requirements, and description of approaches to comply with the rules in Appendix A.

Some have argued that FERC should advocate for a delay in the rules to allow for additional study time to consider potential reliability impacts associated with the retirement of combinations of units. Comments submitted by five electric regional transmission organizations ("Joint RTO comments") did not recommend this approach, presumably for the simple reason that it is practically impossible to study all of the different combinations of potential unit retirements.[1] Indeed, the Joint RTO comments make clear that the information regional planners need most is the unit owners' decisions to retire or retrofit and the schedule in which they intend to proceed. That is why their proposal depends on early submission of a compliance plan.

Exelon's experience with the retirement of its southeast Pennsylvania units underscores the common sense logic of early notification. Following Exelon's advance notice of its intention to retire four units at its Eddystone and Cromby stations, PJM conducted reliability studies of the impact of these announced retirements. Notably, PJM concluded that the retirement of any single unit could be achieved without impacting reliability. Likewise, the retirement of two units could be achieved without affecting reliability. However, PJM determined that the simultaneous retirement of the four units caused localized reliability issues that were not detected when other combinations were studied. It is simply impractical for FERC or the RTOs to study the thousands of permutations of possible retirements without any indication by unit owners of whether they intend to operate or retrofit the plants. And, the argument that FERC should advocate that critical human health standards be delayed years until these speculative analyses are done should be seen for what it is – an attempt to use FERC as a pawn to undermine air regulations under the guise of reliability so that old and uncontrolled units can continue to operate for their remaining lives.

<u>Background on Exelon</u>

Exelon Corporation is comprised of three major operating companies. Exelon Generation Company, LLC owns and operates over 25,000 megawatts ("MW") of nuclear, coal, wind, hydro, solar, gas and oil-fired generation comprising the nation's fifth largest generation fleet. Commonwealth Edison Company is an electric transmission and distribution subsidiary serving over 3.8 million customers in northern Illinois. ComEd has approximately 5,730 circuit miles of transmission lines, 66,000 primary circuit miles of distribution lines, 801 distribution substations and 275 transmission substations. PECO Energy Company is also a utility serving approximately 1.6 million electric customers and 490,000 natural gas customers in southeastern Pennsylvania. PECO has approximately 1,060 circuit miles of transmission lines, 22,000 circuit miles of distribution lines, 332 distribution substations and 115 transmission substations. PECO also has approximately 6,718 miles of gas lines and 5,962 miles of service.

[1] Joint Comments Of The Electric Reliability Council of Texas (ERCOT), The Midwest Independent Transmission System Operator (MISO), The New York Independent System Operator (NYISO), PJM Interconnection, L.L.C. (PJM), And The Southwest Power Pool (SPP), Docket Nos. EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044; FRC-9286-1, August 4, 2011.

Exelon has built its business strategy on the fundamental principle that a clean, reliable and affordable energy portfolio is essential to sound public policy and to sustainable investor value. Toward this end, in 2008, Exelon established a roadmap for investment decisions and public policy advocacy, called *Exelon 2020*. Under that program, we set a goal for the company to reduce, offset or displace 15.7 million metric tons of CO2 emissions per year by 2020, which is equivalent to our company's emissions in 2001, the first full year of our operation as a combined company. While a national carbon policy continues to elude government and industry, we have made solid progress toward our goal, achieving 56 percent of the reduction three years in.

While society continues the debate on the science of climate change, there is no meaningful debate about the effects of sulfur dioxide, particulates, mercury, arsenic, lead, dioxins, hydrochloric acid and other acid gases. CSAPR and the Toxics Rule are mandated by the Clean Air Act, and are neither new nor unexpected; both are the results of previous attempts to implement the Clean Air Act that were rejected by the courts. As described below, many plants are well positioned to comply with these rules. Indeed, all of the coal plants owned (wholly or in part) by Exelon had installed scrubbers by 2009. Simply put, these rules are essential to public health, and compliance is achievable without undue impact on reliability or customer costs.

The Majority of Plants either Comply or Are Well-Positioned to Timely Comply with CSAPR and the Toxics Rule

The electric industry is well on its way to achieving compliance with EPA's upcoming air regulations. Other factors in addition to the anticipation of CSAPR and the Toxics Rule have caused plants to modernize their facilities to reduce air emissions over the past two decades. For instance, many states have adopted regulations ahead of the federal standards regulating emissions of mercury[2] and some companies (such as AEP) installed pollution controls pursuant to consent decrees with government agencies.

Scrubbers (flue gas desulfurization or "FGD") are the most capital intensive technology that a company might install to comply with CSAPR and the Toxics Rule. Approximately 60% of the U.S. coal fleet and 70% of coal-fired units greater than 400 megawatts have scrubbers installed or under construction.[3]

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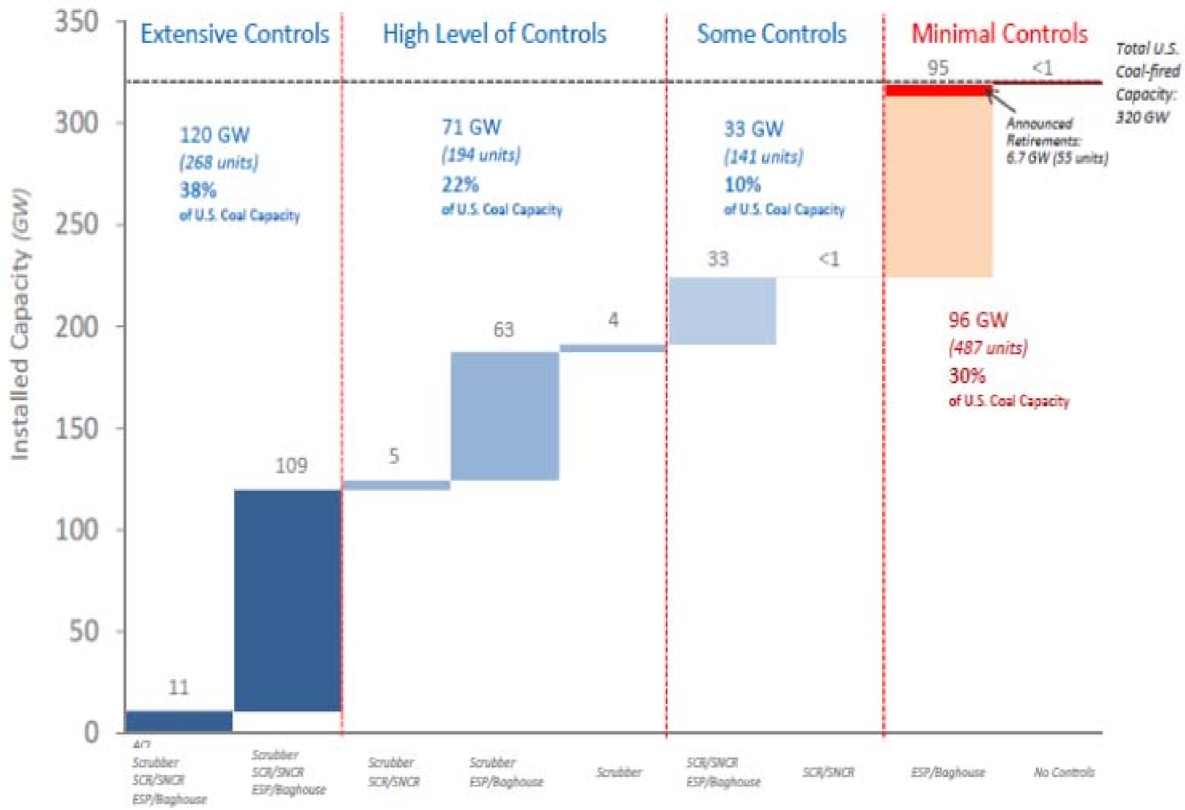
[2] Michael J. Bradley, Christopher E. Van Atten, & Amlan Saha (M.J. Bradley & Associates LLC) & Susan F. Tierney (Analysis Group), "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer 2011 Update," (June 2011) ("M.J. Bradley Summer Update") at App A.
[3] *Id.* at 10.



There are a number of plants that currently comply with each of the mercury, PM and HCl standards in the proposed Toxics Rule. These facilities are set out in the following chart. As discussed below and in Appendix A, most plants that do not fully comply with EPA's proposed standards will be able to come into compliance by adding controls that are less capital intensive than scrubbers and require less than three years to install.

Based on emission rates reported by companies to EPA, many existing U.S. coal-fired units are already compliant with all of EPA's proposed limits for coal-fired electric generating units.

Plant Name	State	Unit	Owner	MW	Coal Rank	PM Control	NOx	SO_2	Hg	Compliance Status: Mercury	Compliance Status: HCl	Compliance Status: PM
G G Allen	NC	3	Duke	282	bituminous	ESP	SNCR	Wet		✓	✓	✓
G G Allen	NC	4	Duke	297	bituminous	ESP	SNCR	Wet		✓	✓	✓
East Bend Station	KY	2	Duke (69%), DPL (31%)	651	bituminous	ESP	SCR	Wet		✓	✓	✓
Hammond	GA	1	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	2	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	3	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	4	Southern	520	bituminous	ESP	SCR	Wet		✓	✓	✓
Hayden	CO	2	Xcel (53%), SRP (30%), MidAmerican (17%)	285	bituminous	FF		Dry		✓	✓	✓
Hayden	CO	1	Xcel (53%), SRP (30%), MidAmerican (17%)	202	bituminous	FF		Dry		✓	✓	✓
Bridgeport Station	CT	2	PSEG	403	subbituminous	ESP + FF			ACI	✓	✓	✓
San Juan	NM	1	PNM Resources (47%), UniSource (20%)	370	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	2	PNM Resources (47%), UniSource (20%)	370	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	3	PNM Resources (47%), UniSource (20%)	544	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	4	PNM Resources (47%), UniSource (20%)	544	subbituminous	FF		Wet	ACI	✓	✓	✓
Clover	VA	2	Dominion	434	bituminous	FF	SNCR	Wet		✓	✓	✓
Chambers Cogeneration LP	NJ	2	Atlantic Power Corporation	285	bituminous	FF	SCR	Dry		✓	✓	✓
Chambers Cogeneration LP	NJ	1	Atlantic Power Corporation	285	bituminous	FF	SCR	Dry		✓	✓	✓
Birchwood Power Facility	VA	1	J-Power	222	bituminous	FF	SCR	Dry		✓	✓	✓
Spruance Genco, LLC	VA	4	Cogentrix	57	bituminous	FF		Dry		✓	✓	✓
Spruance Genco, LLC	VA	2	Cogentrix	57	bituminous	FF		Dry		✓	✓	✓
INDIANTOWN COGENERATION L.P.	FL	1	Indiantown Cogeneration LP	361	bituminous	FF	SCR	Dry		✓	✓	✓
Logan Generating Plant	NJ	1	Keystone Urban Renewal LP	242	bituminous	FF	SCR	Dry		✓	✓	✓
Oak Grove	TX	1	Energy Future Holdings	817	lignite	ESP + FF	SCR	Wet	ACI	✓	✓	✓
Elrama Power Plant	PA	1	GenOn	100	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	2	GenOn	100	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	3	GenOn	125	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	4	GenOn	185	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Colstrip	MT	3	PPL (30%), Puget (25%), PGE(20%), Avista (15%), MidAmerican (10%)	805	subbituminous	Venturi		Wet	ACI	✓	✓	✓
PSEG Mercer Generating Station*	NJ	2	PSEG	343	bituminous	ESP + FF	SCR	Dry	ACI	✓	✓	✓
PSEG Mercer Generating Station*	NJ	1	PSEG	343	bituminous	ESP + FF	SCR	Dry	ACI	✓	✓	✓
Brandon Shores*	MD	1	Constellation	643	bituminous	ESP + FF	SCR	Wet	ACI	✓	✓	✓
Brandon Shores*	MD	2	Constellation	643	bituminous	ESP + FF	SCR	Wet	ACI	✓	✓	✓
PSEG Hudson Generating Station*	NJ	2	PSEG	608	bituminous	FF	SCR	Dry	ACI	✓	✓	✓
				11,468								

Sources: EPA, Plant Owners, MJB&A Analysis

*these units are not present in the ICR database. Information from their owners, however, indicate that they would be able to comply with the proposed standards without the need for any additional controls.

Moreover, all of the technologies necessary to reduce emissions of the pollutants regulated by CSAPR and the Toxics Rule are currently available and already in commercial application.[4] In its April 2011 report entitled "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants," URS Corporation catalogued available technologies and considered how existing facilities with a variety of technology configurations might upgrade to meet the Toxics Rule. URS concluded not only that technology is readily available, but that the technology most likely to be selected by existing facilities, including activated carbon injection ("ACI") for mercury control, particulate controls for non-mercury metals, and dry sorbent injection ("DSI") or dry FGD systems for acid gas control, can typically be installed in less than two years, let alone three.[5]

In addition, plants that choose to install wet scrubbers will be typically able to timely comply with the Rule. The average timeframe for the design, installation, and startup of new wet FGDs ranges from 24 – 44 months. Since the Toxics Rule was issued in March 2011 and will not likely be published in the Federal Register until January 2012 (and thus not effective until January 2015 at the earliest), companies will have had 46 months to comply with the Rule not including any extensions. Plants facing extreme delays in permitting or the supply chain, or with

[4] George Lipinski, Jean Leonard, & Carl Richardson, URS, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants," (April 5, 2011) ("URS Assessment"), at p.7.

[5] Each of these technologies is further discussed in Appendix A.

atypically complex upgrade requirements, have an opportunity to request an additional year to come into compliance with the Rule.

In fact, announcements since the Toxics Rule was proposed have demonstrated that utilities can install wet scrubbers within the compliance period. In recent months, Ameren Energy Generating Co. and Detroit Edison separately entered into contracts for the installation of four FGD systems at plants in Illinois and Michigan, with scheduled completion dates between November 2013 and December 2014.[6]

A recent survey of corporate earnings statements shows companies who own most of the nation's coal-fired generating units are well-positioned to comply with upcoming EPA regulations. Those statements are collected in a recent report by Michael Bradley and Sue Tierney entitled "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update." [7]

The Electric Industry has a Proven Track Record and Effective Tools

The U.S. electric industry has a proven track of responding to regulatory challenges while at the same time maintaining a safe and reliable electric grid. It is important to note that regulatory challenges come from a number of sources, whether clean air rules or endangered species laws or fish protection laws, to name a few. The electric industry has always complied with its environmental responsibilities while meetings its obligation to provide safe and reliable electricity to citizens of the United States, and there is no reason to think it will not do so now.

While portions of the electric industry have been deregulated in the past several decades, the overarching principles of system planning remain intact. These principles include understanding changes in load growth, resource additions, and retirements as well as regulatory changes that may affect short-term and long-term operations.

Planning and operating processes to ensure a safe and reliable electric system are part of the normal course of doing business in the electric industry. Regulations, tariffs and reliability standards governing the electric industry lead to robust system planning designed to assess and meet future electricity demands. As a result, the industry is well-equipped and has many tools to manage retiring units, simultaneous retrofit of units, and any associated reliability impacts.

There are several mechanisms in place to signal future resource needs.

First, the Commission has required open and transparent regional planning processes to be adopted by all jurisdictional transmission providers, as well as those non-jurisdictional

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[6] McIlvaine Co., "FGD and DeNox Newsletter," June 2011, No. 398.
[7] Michael J. Bradley, Christopher E. Van Atten, & Amlan Saha (M.J. Bradley & Associates LLC) & Susan F. Tierney (Analysis Group), "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," (November 2011), App. A.

transmission providers that seek open access service. Under Order No. 890, these processes must consider all potential resources that are sufficient to meet the need, whether they are transmission, generation or demand response solutions. These processes are now in place throughout the country; each transmission provider participates in a process, subject to FERC's oversight. These regional plans take long-term views of the grid and assess reliability and congestion, as well as new and retiring resources. When warranted, the regions will assess changes to the regulatory landscape and inform their stakeholders about changes that may materially affect them. See, for example, PJM's recent coal at-risk study.[8]

In addition, all Planning Authorities are required to conduct long and short-term planning studies to ensure that their systems will comply with all NERC reliability standards. When potential violations are identified, for example, voltage or thermal problems due to the projected retirement of generation, the Planning Authority will determine appropriate mitigation – whether its new lines, new voltage support devices such as SVCs, or new generation through market or other mechanisms. Failure to conduct these studies is a failure to comply with the TPL reliability standards punishable by civil penalties.

Where time is necessary to install needed transmission upgrades, Planning Authorities have the ability to enter into reliability must run agreements with critical generators so that those generators are available to maintain reliability, generally for a limited number of hours. There are many examples of such studies – for example PJM lists the past[9] and pending[10] generator deactivations summaries as well as detailed results.[11] This is the same process that the industry has used for decades.

As the deactivation summaries in PJM demonstrate, faced with reduced demand and low natural gas prices, numerous units have opted in recent years to retire for reasons wholly unrelated to EPA regulations. Yet that process has proceeded without heightened attention from politicians or the media; that is because the process FERC has put in place to address changes to the transmission grid and the generation fleet in wholesale markets (whether additions or subtractions) has worked without incident.

Second, in areas that remain vertically-integrated, integrated resource planning (IRP) is often used to determine the best options for developing new resources and infrastructure additions. IRPs consider a variety of assumptions including forthcoming environmental regulations. Utilities develop a range of scenarios and work with state and local officials to determine the least-cost manner to achieve both reliability needs and environmental compliance.

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[8] PJM, "Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants (Aug. 26, 2011), *available at* http://pjm.com/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx.

[9] *See* http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/generator-deactivations.ashx.

[10] *See* http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

[11] *See* http://www.pjm.com/planning/generation-retirements/gr-study-results.aspx.

Third, as part of industry planning, various organizations in the electric industry perform short-term and long-term assessments of resource adequacy. These assessments identify potential reliability impacts and indicate the amount of capacity needed from the market.

NERC, in its role as the FERC-approved electric reliability organization ("ERO"), publishes a variety of reliability reports including seasonal, long-term as well as special assessments.[12] In these regular reports, which range from the seasonal to ten years in scope, NERC provides a view into reliability metrics including generator planning reserve margins broken down into eight regions, numerous sub-regions and some RTOs/ISOs for the United States and Canada, known as assessment areas; these reports also highlight specific concerns for the electric grid. Moreover, the regional entities, such as ReliabilityFirst also conduct assessments, getting into more detail.[13]

These regular assessments and studies are complemented by in-depth analyses. In its 2010 special scenario assessment on the potential EPA regulations, NERC examined four potential EPA rulemaking proceedings that could result in unit retirements or retrofits. NERC grouped generators based on size and location and determined the effects on planning reserve margins driven by the potential EPA rules in each of sixteen US sub-regions. In addition, Planning Authorities conduct analyses when needed. As the Commission has acknowledged, these scenario assessments are "a critical tool for addressing reliability considerations."[14]

In a report on the impact of EPA regulations, MISO identified capacity and energy costs, resource adequacy, and transmission reliability cost impacts under a range of scenarios. Likewise, PJM used its unique position as the energy and capacity market operator to forecast the future viability of certain generators and thus the effects of environmental rules on the electric market.

Fourth, forward capacity markets provide an important function in many of the nation's wholesale markets and assure that sufficient capacity will be available for future use. For instance, the May 2011 PJM forward capacity auction shows that PJM will have more than enough capacity to meet NERC reliability standards in the 2014-2015 time period by which time companies must comply with EPA's CSAPR and Toxics Rule. More than 4 GW of capacity came into the market in PJM, including new generation and new demand-side resources such as energy efficiency and demand response. AEP and Duke-Ohio, which do not participate in the capacity auction, have certified that they have adequate capacity to ensure reliable service.[15]

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[12] "[T]he Commission expects each assessment to be comprehensive in order for the Commission, the ERO, and the Regional Entities to fulfill their respective oversight responsibilities." Order 672, P 805

[13] *See e.g.*, ReliabilityFirst Corporation, Long Term Reliability Assessment 2012-2021 (Sept. 2011).

[14] *Three Year Assessment Order* at P 180.

[15] Though FERC has approved such markets in several other regions, including ISO-NE and NYISO, some regions have not moved as quickly to adopt this important tool. This is an area where FERC can encourage industry participants engaged in market development to build sufficient lead time into their market designs. For example, the two-month forward period currently proposed by MISO is ill-equipped to deal with changing conditions of any

Fifth, increased demand side management and conservation will also play a critical role in alleviating potential reliability impacts from the transition of the fleet. Increased energy efficiency may offset future demand growth. Increasing available demand response resources will provide planning and operating flexibility by reducing peak demand and will consequently increase the cushion to manage the effect of retirements to ensure minimal impact on reliability. This was confirmed by the May 2011 PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.8 GW of new demand response resources cleared the auction.[16]

The industry is already responding to these planning processes, assessments, and market signals. In total, 41.5 GW of new plant capacity is slated to be placed in service through 2014 when both CSAPR and the Toxics Rule will be in effect. Another 6.7 GW of capacity is in advanced phases of permitting.

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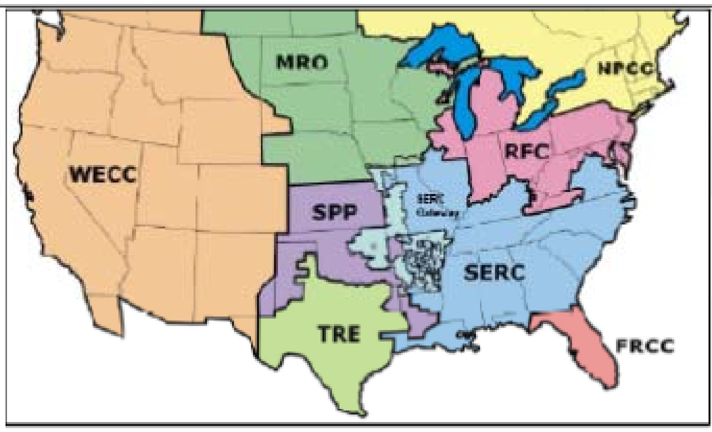
magnitude. *See, e.g., Midwest Independent Transmission System Operator, Inc*., Docket No. ER11-4081-000, "Capacity Suppliers' Motion for Leave to Answer and Supplemental Answer" at 8-9 (filed October 31, 2011). A longer planning period makes for a much more efficient market, permitting new, as-yet-unbuilt resources and transmission projects to be compared with generation offered in the capacity auctions through a transparent process that results in the most efficient solution.

[16] Ade Dosunmu, "Up in Smoke," Fortnightly's Spark (June 29, 2011) ((indicating that demand response resources cleared the PJM capacity auction, displacing coal-fired generation that was offered).

New Planned Generating Capacity Additions by Region (as of 9-2011)



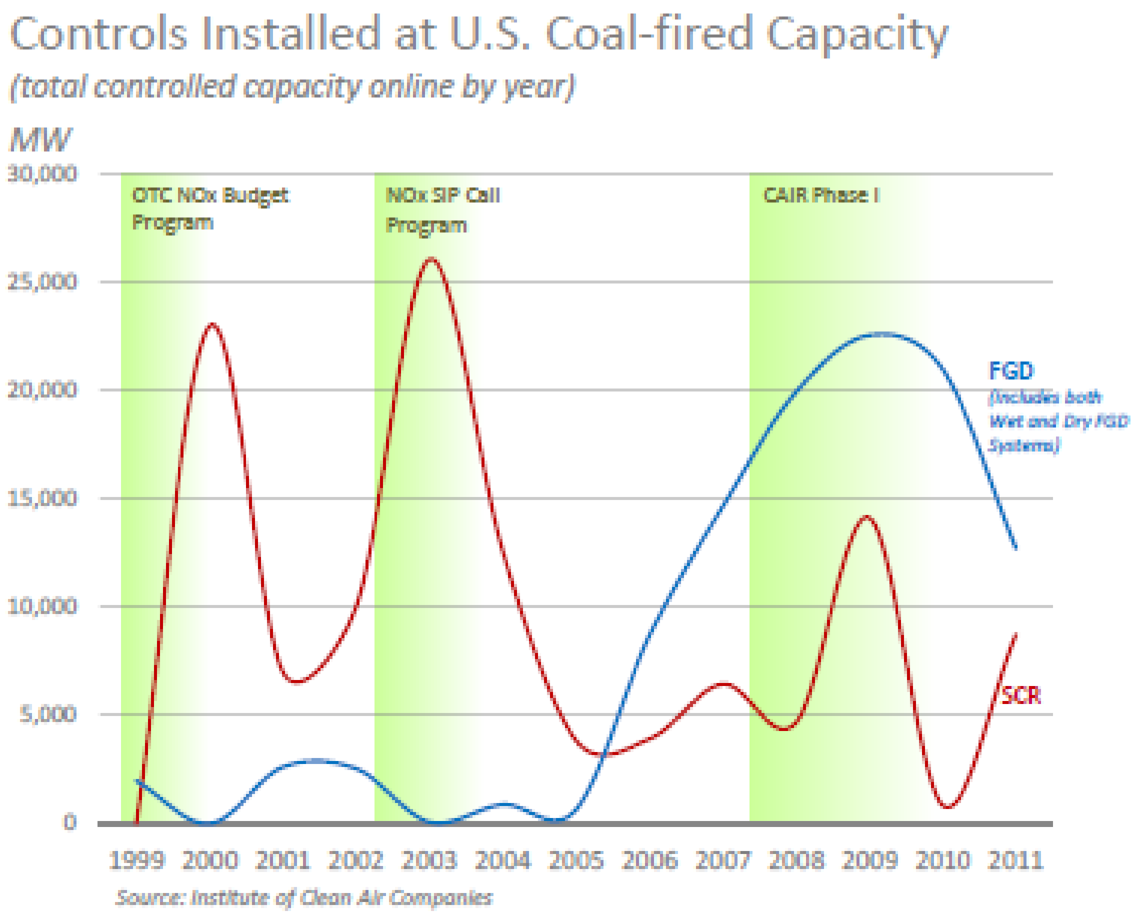
Regional Reliability Councils

Reliability region	Generating Capacity (MW) Under Construction by Region						
	2011	2012	2013	2014	2015+	Total	Total by end of 2014:
TRE	453	1,003	-	-	302	1,758	1,456
FRCC	6	46	1,295	-	26	1,373	1,347
MRO	1,094	601	261	-	2	1,957	1,956
NPCC	2,057	1,788	647	640	1,404	6,536	5,132
RFC	2,646	1,892	198	139	47	4,922	4,874
SERC	2,165	6,457	3,615	681	61	12,979	12,918
SPP	580	645	7	-	-	1,232	1,232
WECC	1,613	5,449	4,379	1,109	517	13,066	12,550
Total	10,614	17,881	10,401	2,569	2,358	43,823	41,465

	Generating Capacity (MW) in Advanced Development Phases but Not Under Construction						
	2011	2012	2013	2014	2015+	Total	Total by end of 2014:
TRE	1	2,030	-	1,000	3,635	6,666	3,031
FRCC	30	48	117	1,395	4,638	6,228	1,590
MRO	225	600	-	-	1,068	1,892	825
NPCC	203	917	1,324	1,187	1,416	5,046	3,631
RFC	101	1,036	859	15	5,250	7,262	2,011
SERC	-	939	29	1,452	10,698	13,117	2,419
SPP	8	777	-	-	763	1,547	784
WECC	944	1,901	4,244	5,341	14,146	26,576	12,430
Total	1,512	8,246	6,572	10,390	41,614	68,334	26,720

Source of data: SNL Financial

Likewise, the electric industry has previously responded to CAA provisions requiring investments in new pollution control technology without jeopardizing reliability. During the peak of scrubber construction, between 2008 and 2010, approximately 60 GW of coal capacity was retrofit with scrubber controls, highlighting the industry's ability to complete a substantial number of retrofits over a short period of time.[17] In 2009 and 2010, the industry completed between 50 and 60 scrubber retrofits each year.[18]



In contrast, EPA's final modeling indicates that 8.9 GW of new SO2 controls will be required for 2014 compliance with CSAPR, including 5.7 GW of wet scrubbers and 3 GW of dry sorbent injection. EPA also estimates that 25 GW of Dry FGD will be installed in addition to the 29 GW base case (for a total of 54 GW).[19] The Toxics Rule will generate 1 GW of wet FGD beyond the

[17] Michael J. Bradley, Christopher E. Van Atten, Amlan Saha, & Carrie Jenks (M.J. Bradley & Associates LLC) & Susan F. Tierney & Paul J. Hibbard (Analysis Group), "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," ("M.J. Bradley Report") (August 2010), p. 19.

[18] Id.

[19] 76 Fed. Reg. at 48,279.

174 GW in the base case (for a total of 175 GW).[20] The industry will be able to handle these retrofits as it has done before.

If, however, despite the tools described above, there is a conflict between the needs of the system and the plans of a unit to retire or shutdown to retrofit, there are mechanisms in existing law to protect the grid and allow the units to remain operating until necessary reinforcements are located. In order for these mechanisms to work, however, we have urged EPA to require all unit owners that need more time to comply to submit compliance plans shortly after the Toxics Rule is finalized. Early identification of compliance plans will provide regional planners and wholesale markets the information necessary to internalize that information and reflect it in resource choices.

First, I will discuss the reliability impacts of retirements and then will discuss considerations related to retrofitting units.

The electric system can manage reliability impacts from retirements of coal plants.

As previously indicated, most units comply or are well-positioned to comply with CSAPR and the proposed Toxics Rule. It is true, however, that some units will elect to retire rather than to retrofit with controls. Retirements are driven by many economic factors, not simply the cost of pollution control equipment. These factors include decreases in demand due to economic conditions, the cost of alternative generation sources, many of which are decreasing, the increasing competitiveness of large scale demand-side resources, and the increasing capacity and O&M costs associated with inefficient units that have been in existence since the Eisenhower administration. First among these factors is that the development of abundant, domestic shale gas resources has placed economic pressure on coal facilities even in the absence of EPA regulations. Many of the issues identified in the pre-hearing request for evidence,[21] including potential mothballing of power plants, inadequate voltage support, loss of system inertia, and the need to modify contingency planning models, are implicated by retirements caused by low natural gas prices and reduced demand and would exist even without EPA regulations.

Without EPA regulations, gas-fired power plants increased their output from 20 percent in 2007 to 24 percent in 2010 of all power production in the U.S., while coal-fired generation decreased from 50 percent in 2007 to 45 percent in 2010. Therefore, regardless of the costs associated with the Toxics Rule and other EPA regulations, some coal-fired power plants were already economically unsustainable. As M.J. Bradley points out, "Of the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM, in addition to approximately 10

[20] Regulatory Impact Analysis of the Proposed Air Toxics Rule: Final Report ("RIA"), at 8-14, fig. 8-6 (March 2011).
[21] Reliability Technical Conference, Docket No. AD12-1-000; North American Electric Reliability Corporation, Docket No. RC11-6-000; Public Service Commission of South Carolina and the South Carolina Office of Regulatory Staff Docket No. EL11-62-000, Request for Evidence of Commissioner Philip D. Moeller on EPA Issues for the November 2011 Reliability Conference, November 14, 2011.

GW of coal generation that has or will be retired during the seven years from 2004 to 2011, another 11 GW faces a troubling economic outlook."[22]

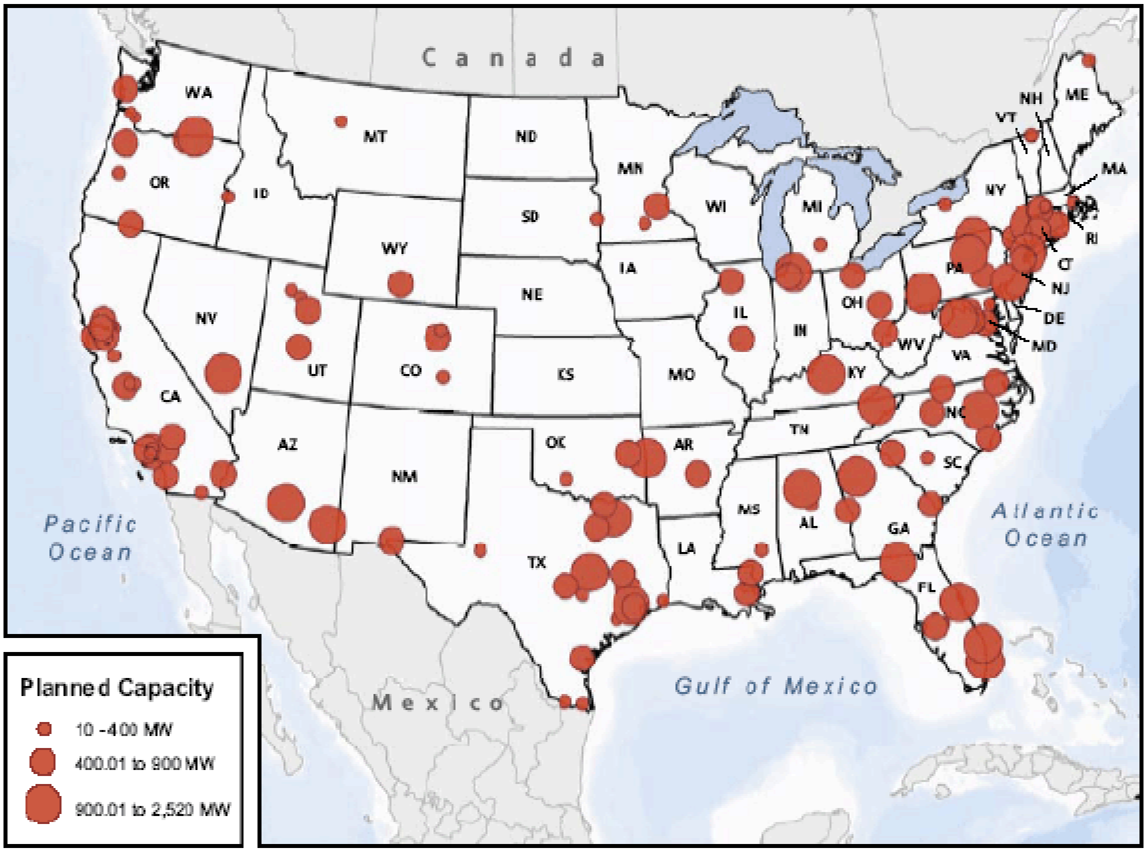
For example, Exelon's decision to retire its Eddystone and Cromby units in southeastern Pennsylvania was primarily driven by economic factors other than environmental regulation. Similarly, the retirements announced by AEP in June 2011 are driven by economic factors other than EPA's CSAPR and Toxics Rule. First, under a 2007 consent decree, AEP already agreed to retire, retrofit or repower 4,500 MWs of the 5,500 MW of announced retirements that it now attributes to CSAPR and the Toxics Rule. Moreover, the plants that AEP intends to retire will have an average age of 55 years old in 2014, much beyond their designed lifetimes, and many of the plants are smaller, inefficient and have low average utilization rates. Ten of the units AEP plans to close had already been pulled back to part-time operation last summer since they were no longer economic to run full-time due to declining natural gas and power prices and reduced demand.

To be sure, there will be incremental retirements caused by EPA's CSAPR and proposed Toxics Rule. However, the development of abundant natural gas resources will lessen the burden of coal plant retirements in two ways. First, lower natural gas prices will cause existing, under-utilized natural gas plants to be dispatched more often. In 2007 and 2008, coal enjoyed a price advantage relative to natural gas.[23] As a result, existing gas-fired plants were comparatively underutilized, operating at an average of 33% of the time compared to 56% for coal-fired units.[24] As gas prices have fallen relative to coal, gas-fired capacity factors have increased. Existing gas units have significant untapped potential, which can be utilized to maintain reliability without the need to undertake new construction. Indeed, if all coal-fired units with a name plate capacity of less than 200 MW were retired, the power produced by these retired units could be replaced using only 5% of the *unused* capacity of existing combined cycle gas units.[25]

Second, the expectation of continued low natural gas prices for at least the next two decades allows the replacement of older, inefficient coal units with new gas-fired capacity. Combined cycle gas plants allow a much more efficient use of the heat content of fossil fuels and take less capital investment and time to permit than baseload coal or nuclear facilities. Consequently, much of the new power plant capacity under construction or in advanced planning is natural-gas combined cycle facilities. As of August 2011, approximately 11.6 GW of new gas-fired capacity is expected to be operational by the end of 2014.[26] Another 6.4 GW is in advanced permitting. The map below shows this capacity as well as another 18.4 GW of announced projects.

[22] M.J. Bradley Report at 20.
[23] *Id.* at 13.
[24] *Id.*
[25] In 2008, the 17 GW of coal-fired units of less than 200 MW achieved a 45% capacity factor, while the 228 GW of CCGT units achieved a 35% capacity factor. *See* M.J. Bradley Report at 7 & tbl. 4.
[26] SNL Energy, as of August 24, 2011. An additional 10.8 GW of gas-fired combined cycle projects that are in advanced permitting or announced by project developers, for an in-service date of 2015.

Planned natural gas combined-cycle projects in the US



As of Aug. 24, 2011
Source: SNL Energy

As the shale gas develops, pipeline infrastructure has been expanded to take the produced gas to markets. In fact, in many cases, the pipelines are actively looking for power plant customers to serve. In the last 6 months, no less than three pipelines have visited Exelon to inquire whether we are considering new gas-fired projects. Given the expanse of the Marcellus and Utica shales and their relative proximity to projected retired coal fired generation, our expectation is that connecting new gas-fired capacity will not be a challenge. Plants in Pennsylvania and Ohio are sitting right on top of the gas fields and will need nothing more than simple laterals. The pipeline capacity already being built in the Mid-Atlantic will move shale gas to markets where coal-fired generation is being replaced by gas-fired CCGT's, such as in Tennessee, Virginia, North and South Carolina. The southeast is already geared up with multiple pipeline projects to provide incremental capacity to support new-gas fired generation.

Units that elect not to retrofit with controls must retire within three years of the promulgation of the Toxics Rule. However, if there are units that are necessary for grid stability despite the availability of the above-referenced resources, clearly these units should receive an extension of time until necessary upgrades are constructed. The RTOs have proposed a backstop process for these scenarios, which the RTOs anticipate "would not need to be invoked often, if at all."[27] Under the Joint RTO proposal, units that seek extra time to comply would be required to notify their RTO within one year from the effective date of the final rule, or January 2013, whichever is sooner.[28] The RTO would analyze the request through its planning process, and if it determined that the unit was "reliability critical" and the necessary reinforcements or replacement resources would take more than three years to complete, the unit would be granted an extension of time to comply.[29] This same approach can be developed for regulated states where RTOs do not control and monitor the transmission grid.

Environmental impacts as a result of the operation of units seeking to retire past the compliance date for the proposed Toxics Rule should be mitigated to the greatest extent possible. There is no reason that units determined by RTOs or state planners to be "reliability critical units" should run unrestricted during any necessary extension period. To the contrary, allowing uncontrolled units to run in a business-as-usual manner will distort the market signals that the Commission has worked to develop through its many reforms to bring competition to wholesale markets. In order for the market to signal when and where new resources are necessary, uncontrolled, lower cost units that would otherwise retire should not be permitted to run past the compliance deadline except if they are reliability critical and then, only when needed to meet the identified reliability need.

Plant owners are accustomed to operating their units in adherence with run restrictions. Emissions can be significantly reduced if plants needed for reliability are permitted to operate only during the brief periods when required to preserve reliability (i.e., when no other resource is available to meet the electricity need.) For example, Exelon is currently subject to an agreement with the Pennsylvania Department of Environmental Protection under which Exelon was permitted to continue to operate its Eddystone and Cromby units in southeastern Pennsylvania past Exelon's originally planned date to retire those units, subject to a reliability-only dispatch limitation. As a result, Cromby and Eddystone have significantly reduced production and resulting harmful pollution emissions since the reliability-only dispatch limitation became effective.[30] Importantly, these units remained available to maintain reliability, on some of the hottest days when demand peaked.

<u>Retrofits of pollution control technology can be managed without jeopardizing reliability.</u>

As discussed above and in Appendix A, all of the technologies necessary to reduce emissions of the pollutants regulated by CSAPR and the Toxics Rule are currently available, already in

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[27] Joint RTO Comments at 6.
[28] *Id.*
[29] *Id.*
[30] John Hanger, "Reliability-Only Dispatch: Protecting Lives & Human Health While Ensuring System Reliability," (October 2011).

commercial application and can typically be installed within three years. Moreover, some units will be able to comply by simply operating existing pollution controls more often.[31]

There are, however, options available to allow unit owners more time to install controls in those few instances where more time is legitimately needed. The CAA authorizes the permitting agency (EPA or a state) to "issue a permit that grants an extension permitting an existing source up to 1 additional year to comply…if such additional period is necessary for the installation of controls." 42 U.S.C. § 7412(i)(3)(B). The EPA should establish clear guidelines for a one-year extension for those plants that need additional time to install controls as long as the owners meet appropriate milestones to complete design work and timely enter into construction contracts to do the work. The key operative language is "necessary for the installation of controls." Given the variety of ways in which plants will respond to the rule, there is not a legally defensible opportunity for EPA to declare a blanket extension for all plants. For example, some plants meet the standards now, and some will easily be able to install equipment necessary to meet the standards in three years. Therefore, these plants could not justify an extension under the language of the statute. A categorical extension for every unit in the nation would require a technical finding that additional time is necessary for every unit, and this is not possible. Moreover, there is a practical concern that a blanket extension will simply incent companies to delay work for a year ultimately leading back to the same claims of reliability concerns and labor and equipment shortages a year later.

As with any maintenance outage, the system operators, whether RTOs/ISOs or non-RTO operators, must comply with NERC Standards to coordinate planned outages.[32] System operators have protocols in place to schedule generator and transmission outages to maintain reliability and adequacy of the system and minimize costs to customers, such as congestion.[33] One of those protocols involves sufficient notification of a maintenance outage to allow the system operator to perform the analysis. Again, this type of analysis and planning is a core function that the electric system operators have performed for decades.

In addition, in the very unlikely event that a plant will require more than four years to comply with the Rule, EPA may exercise its enforcement authority under the CAA to enter into consent decrees that provide plant owners more time to install controls. This process should ensure that a unit runs only when it is needed for reliability purposes; does not receive any undue economic gain; meets appropriate and enforceable milestones; and does not face penalties for operating a unit to meet a reliability need. As noted above, for all of these options, it is critical that unit owners identify in advance which units need more time and which units will retire so

[31] For instance, in the NEEDS database, which is the input file into IPM that contains unit level information, that EPA used to model CSAPR, EPA showed 194 GW of scrubbed coal as of 2011 with 50.4 GW listed as dispatchable and 139.1 GW of SCR with 11.3 GW listed as dispatchable. See, http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html

[32] NERC Reliability Standard TOP-003-1, Planned Outage Coordination.

[33] *See*, *e.g.*, ISO New England Annual Maintenance Schedule, http://www.iso-ne.com/genrtion_resrcs/ann_mnt_sched/index.html.

that the regulatory process of evaluating those requests for additional time is efficient and so that transmission upgrades or market solutions develop.

Conclusion

The electric industry has a long history of addressing regulatory and economic changes like the clean air regulations under development at EPA. This is not the first time the industry has faced new environmental regulations, changes in fuel prices and demand, or other significant events. Existing grid assessment tools are sufficient to identify impacts of retirements and to coordinate retrofit schedules, and tools in existing law are sufficient to provide more time to units that need it. FERC should continue to provide expertise and support to EPA and industry as the regulations are implemented. Beyond that, FERC should allow its existing processes and safeguards to work.

Appendix A

CSAPR

The Clean Air Act ("CAA" or "Act") requires EPA to set national ambient air quality standards ("NAAQS") for each pollutant that endangers public health or welfare. 42 U.S.C. §7408. Particulate matter ("PM2.5") and ozone, which are the subject of the CSAPR, are two of only six pollutants that EPA determined have serious human health impacts and for which EPA has issued a NAAQS. The Clean Air Act requires states to submit implementation plans, known as SIPs, describing how they will comply with the NAAQS within three years of issuance. 42 U.S.C. §7410(a). Recognizing that transported air pollution severely impairs the health of residents and burdens the economies of downwind states, the Act requires that SIPs prohibit sources within one state from contributing significantly to a downwind state's non-attainment or interference with maintenance of the NAAQS. *Id.* If a state is untimely in submitting a compliant SIP to EPA, EPA must promulgate a federal implementation plan ("FIP") for the state to follow. 42 U.S.C. §7410(c)(1).

EPA issued the NAAQS for ozone and particulate matter that are the subject of the CSAPR in 1997.[34] 62 Fed. Reg. 38,856 (July 18, 1997). States were thus required to submit SIPs within three years thereafter demonstrating that (1) they would attain the NAAQS by the requisite deadline; and (2) would not significantly contribute to a downwind state's non-attainment of the NAAQS. However, EPA found that many states did not demonstrate in their SIPs that they would not significantly contribute to downwind nonattainment. 70 Fed. Reg. 21,147 (April 25, 2005). Thus, EPA adopted a rule that was designed to enforce the "good neighbor" provisions of the Act and ensure that upwind pollution would no longer prevent downwind states from achieving attainment with the NAAQS. That rule, the Clean Air Interstate Rule ("CAIR"), was issued in 2005. 70 Fed. Reg. 25,162 (May 12, 2005). CAIR required reductions in sulfur dioxide ("SO2") and nitrogen oxides ("NOx"), which are precursors to PM2.5 and ozone. *Id.* NOx and SO2 react in the atmosphere to form PM2.5, and NOx contributes to ground level ozone formation during the summer months. These pollutants are transported long distances, causing increased pre-mature deaths and illnesses as well as economic hardships in downwind states.

CAIR required first phase NOx and SO2 reductions in 2009 and 2010, respectively, and second phase reductions in 2015. *Id.* A number of states sued EPA, however, based on their view that CAIR would not, in fact, sufficiently reduce the contribution that upwind states contributed to their poor air quality. *North Carolina v.* EPA, 531 F.3d 896, 929 (D.C. Cir. 2008). On review, the Court of Appeals for the District of Columbia invalidated CAIR in 2008, but allowed it to remain in force until EPA promulgated an appropriately protective replacement rule, recognizing CAIR's inadequate reductions were better than none.

The CSAPR addresses the defects that the Court found in CAIR in *North Carolina v. EPA* by establishing a FIP requiring 27 states to reduce SO2 and NOx emissions. Under that decision,

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[34] CSAPR also requires reductions in interstate air pollution necessary to comply with the 24 hour PM2.5 NAAQS issued in 2006. 76 Fed. Reg. 48,208, 48,211 (Aug. 8, 2011).

EPA was required to issue a FIP to immediately bring states into compliance with the NAAQS because certain compliance deadlines have already passed. *North Carolina* at 25. CSAPR sets a state budget of allowances plus a variability limit for each state to ensure that each state will reduce its significant contribution to pollution in downwind states. Then, under the FIP, EPA allocates state budgets to individual units in each state and sets up a separate allowance trading program for Group 1 SO2, Group 2 SO2, annual NOx and ozone season NOx whereby sources can trade emission allowances within the same program in the same or different states (except that Group 1 SO2 states cannot trade for SO2 allowances with Group 2 SO2 states). In other words, units in states covered by CSAPR are not required to install any particular control technology or take any specific action to comply, other than to forfeit allowances equal to their emissions. Units that emit pollutants in excess of their allocation must procure allowances sufficient to match that level of emissions. Units that reduce their emissions below their allocated number of allowances may trade with other units in their generating system or sell the allowances to other power plant operators on the open market.

The first phase of compliance under CSAPR begins on January 1, 2012 for SO2 and annual NOX reductions and May 1, 2012 for ozone season NOX reductions. 76 Fed. Reg. at 48,211. EPA set state budgets for the first phase of CSAPR compliance based on what can be achieved by existing pollution control installations and those under construction and available for 2012. *Id.* at 48,279-28,280. EPA recognized that many companies with controls do not operate them all the time (given that price signals do not justify operating the controls) and correctly concluded that companies can make significant emissions reductions by maximizing the operation of dispatchable pollution controls. *Id.* at 48,252. In addition, companies can comply with Phase I by switching fuels or purchasing allowances.

The second phase of SO2 reductions begins January 1, 2014. *Id.* at 48,211. EPA's final modeling indicates that 8.9 gigawatts ("GW") of new SO2 controls will be required for 2014 compliance, including 5.7 GW of wet scrubbers and 3 GW of dry sorbent injection. *Id.* at 48,279.

EPA has also recently proposed a rule to make additional technical corrections to some state emission budgets that will further increase the quantity of available emission allowances. 76 Fed. Reg. 63,869 (Oct. 14, 2011). This proposed rule also provides that EPA's assurance provisions, which serve to limit the extent of interstate trading of emission allowances so that each state reduces its actual contribution to downwind pollution, would not take effect until 2014. Therefore, the proposed rule allows unlimited interstate trading in each trading program for the first two years of CSAPR. These provisions allow even greater flexibility in complying with the Rule.

Recent activity has confirmed that CSAPR's allowance trading regime is working. The generation industry has already begun to implement CSAPR, as allowances have already started to trade.[35] Bid-ask spreads have closed and prices have declined as regulatory certainty increases. As operational plans for 2012 crystallize and regulatory certainty continues to improve, trading volumes will increase. Allowance prices have dropped since the first CSAPR allowance trades in August 2011 and SO_2 allowances that EPA expected would sell for approximately $1,000 per ton now sell for $600 or less. This downward price trend mirrors what occurred at the start of prior cap-and-trade programs, including CAIR. Allowance prices drop because risk and uncertainty premiums paid at the outset of new programs recede after the programs have begun and prices move closer to fundamental "supply-demand" levels.

According to EPA, CSAPR will help avoid tens of thousands of premature deaths and illnesses, achieving hundreds of billions of dollars in public health benefits. Pollution reductions will also improve visibility in national and state parks, and increase protection for sensitive ecosystems.

<u>Toxics Rule</u>

EPA's proposed Toxics Rule creates the first ever national limits on power plant air emissions of hazardous pollutants, such as mercury, hydrochloric and sulfuric acids, arsenic and other toxic metals. In the 1990 CAA amendments, Congress required that EPA set limits for emissions of hazardous air pollutants listed in the Act from existing power plants that are no less stringent than the levels achieved in practice by the best performing 12% of plants regardless of the means used to achieve that level. 42 U.S.C. §7412(d)(3). This average is commonly referred to as the "MACT floor." New sources must achieve the emission reductions achieved by the best controlled similar source. *Id.* Though some states have passed laws restricting emissions of air toxics from power plants, there are no federal limits on these emissions of toxic pollutants, twenty-one years after the passage of the CAA amendments.

The Toxics Rule is fundamentally different from CSAPR in that it is a command and control program. EPA does not have the flexibility to set up a trading program to reduce emissions. Instead, the CAA requires existing plants to reduce their emissions as expeditiously as practicable, but in no event later than three years after the effective date of the rule. 42 U.S.C. §7412(i)(3). The proposed Toxics Rule provides the maximum amount of compliance time permitted by the Act. The Act authorizes EPA or a state with an approved Title V permitting program to grant a one-year extension of time "if necessary for the installation of controls." *Id.* In addition, the Act authorizes the President to exempt a source from compliance for a period of not more than 2 years if the President determines that "the technology to implement such standard is not available and that it is in the national security interests of the United States to do so." 42 U.S.C. § 7412(i)(4). Finally, EPA can exercise its enforcement discretion under the Act to allow more time if a source has justified the need for an extension.

Rather than setting an emission limit based on the best performing 12% of all units in the Nation, the CAA allows EPA to calculate emission standards for subcategories of sources based

[35] FirstEnergy Solutions conducted an auction of allowances on November 17, 2011, in which First Energy sold a large number of allowances but a number of allowances remained unsold.

on those sources' size, type and/or class. 432 U.S.C. § 7412(d)(1). Sub-categorization is appropriate where differences in the class, size, or type of sources have a meaningful effect on emissions performance, which, in turn, impacts the choice of control technology. EPA used this authority in the proposed Toxics Rule and calculated separate MACT floors for hazardous air pollutants in each of the following subcategories: coal-fired plants, oil-fired plants, petroleum coke plant and IGCC plants. 76 Fed. Reg. 25,027 (May 3, 2011). For mercury only, EPA further subcategorized and proposed separate mercury limits for boilers designed to burn lignite and non-lignite coal. *Id.* There is no basis for additional sub-categorization in the proposed Toxics Rule, such as on coal rank or unit size, for instance, because technology available to achieve EPA's proposed standards is not dependent on whether a plant burns bituminous or subbituminous coal or the size of unit.

EPA is also authorized to set an emission standard for a surrogate for a group of pollutants that are controlled similarly rather than proposing a distinct emission standard for the almost 200 hazardous air pollutants listed in the CAA. In the proposed Toxics Rule, EPA established emission standards for total particulate matter as a surrogate for non-Hg metals[36] and hydrogen chloride (HCl) as a surrogate for acid gases.[37] 76 Fed. Reg. 25,027 . EPA proposed individual mercury limits because PM control technology cannot effectively treat mercury.

There can be no dispute that EPA's standards for existing sources are achievable. Since the passage of the 1990 CAA amendments, many pollution control options have been developed and are available to achieve the emissions standards in the proposed Toxics Rule. By definition, the standards are achievable, given that they are based on technologies that existing plants are already using to meet other requirements. In fact, most operating power plants in the Nation either already comply or are well-positioned to comply with the emissions standards in the proposed Toxics Rule.

For example, most plants have existing particulate matter control technology that can be used to meet EPA's proposed standard for total PM, as a surrogate for non-mercury metals. Some of those controls will need to be upgraded or replaced, either of which can occur within the three year compliance period.[38] Activated carbon injection (ACI) is the low-cost technology choice to reduce mercury emissions. ACI can be designed, installed and tested within twelve to eighteen months.[39] With respect to acid gases (HCl), EPA anticipates that dry sorbent injection (DSI) will be the low-cost technology choice for plants that burn low sulfur coal and dry scrubbers (also known as spray dryers) with fabric filters will be the low-cost technology choice for higher sulfur, bituminous coals.[40] DSI involves injecting sorbent materials at various points along the

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[36] Total PM is a surrogate for non-Hg metals because these can be treated in a manner similar to PM – using ESPs or fabric filters.

[37] EPA proposed using HCl as a surrogate for acid gases because the other acid gases behave and are treated similarly.

[38] George Lipinski, Jean Leonard, & Carl Richardson, URS, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants," (April 5, 2011) ("URS Technology Assessment"), p. A-1, A-3.

[39] Id.

[40] Regulatory Impact Analysis of the Proposed Air Toxics Rule: Final Report ("RIA"), at 232 (March 2011).

flue gas path to react with acid gases, such as HCl, to capture the reaction products. DSI systems can be operational in a nine to twelve-month period.[41] Dry scrubbers can be designed, installed and operated in two to three years.[42] As a result of CSAPR and other federal, state and local actions, many plants burning bituminous coals may choose to install a wet scrubber to meet these requirements, which can be designed, installed and operational in about 24 to 44 months.[43]

Opponents of the proposed Toxics Rule claim that EPA overestimates the use of DSI to control acid gases. These claims are without merit. DSI is a mature and proven technology that is currently being used for treatment of acid gases at approximately 90 units.[44] In addition, as set out below, several companies have announced plans to use or consider using DSI to comply with EPA's proposed HCl limit:

- PSE&G may install DSI at its Bridgeport Harbor facility, which is a coal unit burning low sulfur coal, to build an additional compliance margin to meet the HCl limit. PSE&G does not foresee installing a wet scrubber to comply.
- Midwest Generation is also considering retrofitting with DSI to comply with the proposed Toxics Rule. In November 2010 and February 2011, the Illinois EPA issued construction permits authorizing Midwest Generation to install DSI at its Waukegan and Powerton generating stations.
- Conectiv Energy installed a DSI system at its Edge Moor facility to comply with Delaware's multi-pollutant emissions control rule. The project operated from 2009 to mid-2010 and resulted in significant SO2 reductions at the plant. Since the purchase of the facility by Calpine in mid-2010, coal is no longer burned and the system is no longer needed.
- In New York, NRG installed a DSI system at its Dunkirk (530 MW) and Huntley stations (380 MW). This project is the first of its kind in the U.S. in which Trona and powder-activated carbon (PAC) are simultaneously injected into the flue gases to control both SO2 and mercury emissions. Performance tests indicate that emissions of SO2 have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/mmBtu.
- Duke Energy installed DSI systems in 2010 at its Gallagher generation stations. According to the company, the system will reduce SO2 emissions by 50 percent. Duke Energy expects the DSI system to help the company comply with the requirements of CSAPR and the Toxics Rule.

Further, EPA included numerous provisions in the proposed Rule giving plants flexibility in complying with Rule while assuring that harmful air emissions are adequately controlled. These

41 URS Assessment at A-11.
42 URS Assessment at A-15.
43 URS Assessment at A-22.
44 URS Assessment at A-10.

numerous examples include: (1) the work practice standards for dioxin/furans and non-dioxin/furan organic HAPs, (2) EPA's treatment of variability in setting emission standards, (3) the provisions allowing emissions averaging to demonstrate compliance, (4) the choice for existing sources to comply with either input-based or output-based emission limitations, (5) the statutory eligibility for a one-year extension to comply with the Rule in the event that the additional time is necessary for installation of controls, and (7) the provision of an affirmative defense to any malfunction.