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Statement of Michael Catanzaro
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Listening Session on EPA's Proposed Section 111(d) Clean Power Plan
Pennsylvania Department of Environmental Protection
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Deputy Secretary Brisini, DEP staff, thank you for the opportunity to testify this morning on EPA's proposed Section 111(d) Clean Power Plan. My name is Michael Catanzaro, and I'm Managing Director of the Energy and Natural Resources practice with FTI Consulting, Inc. Before joining FTI Consulting, I spent several years in public service, including as Senior Energy Advisor to the Speaker of the U.S. House of Representatives and Associate Deputy Administrator of the Environmental Protection Agency, where I worked on, among other things, implementation and enforcement of the Clean Air Act.

FTI Consulting is a global business advisory firm dedicated to helping organizations protect and enhance enterprise value in complex legal, regulatory and economic environments. FTI has been helping several coops and merchant plants, such as the Homer City Generating Station in Indiana County, assess possible impacts of EPA's proposed Clean Power Rule to implement section 111(d) of the Clean Air Act[1].

I want to recognize the Deputy Secretary and his staff at the outset for DEP's White Paper, released in April, outlining a recommended state framework for compliance with EPA's Clean Power Plan. The white paper delineates a number of sound principles that EPA should follow to provide states with true, meaningful compliance flexibility. It also includes alternative proposals that, among other things, provide a more realistic baseline emissions profile for the Commonwealth and remove regulatory obstacles that discourage plant efficiency improvements. I will comment on those proposals in more detail later in my testimony.

Homer City Generating Station

Today I am speaking on behalf of Homer City Generating Station. Homer City is a 1,884-MW coal-fired electric generating facility that provides enough electricity to power 2 million homes. The facility has and continues to be a good citizen for the local community and the Commonwealth as a whole: Homer City has about 260 full-time employees, 75 percent of whom are unionized; supports thousands of additional local jobs; and purchases 100 percent of its coal from Pennsylvania coal producers. It also pays $2.9 million annually in state and local taxes.

In addition to its many economic benefits, Homer City is committed to environmental stewardship. The facility is undergoing an $800 million renovation project to install state-of-the-art pollution control equipment. As the Pennsylvania DEP stated in 2012, "The controls are expected to remove approximately 100,000 tons of actual sulfur dioxide emissions annually. Secondary control of particulate matter (PM/PM10/PM2.5), mercury, lead, sulfuric acid mist, hydrogen chloride, fluorides, and volatile organic compounds (VOCs) is also expected." When completed, this project will make Homer City one of the cleanest burning coal-fired power plants in the U.S.

[1] 42 U.S.C. § 7411(d).

Homer City is a so-called "merchant" power plant, meaning it sells power into wholesale, competitive electricity markets, has no way to pass on its environmental costs directly to rate payers, and gets dispatched based on variable costs. For purposes of reducing carbon dioxide emissions, this point is significant. Merchant plants are different than integrated utilities, which can obtain a regulated rate of return from state officials. Moreover, unlike other electric generators in the Commonwealth, which have a diversified fleet consisting of gas-fired plants and renewables, Homer City is a stand-alone power generation facility. As a result, because no cost-effective, commercially available technology exists to control carbon dioxide emissions, Homer City's only option to comply with the proposed rule would be to purchase credits from lower emitting entities (in the event Pennsylvania adopts or joins an emissions trading regime) or curtail operations.

Both of these options would cause Homer City to operate less frequently, and as a result would impair its ability to recover its $800 million investment, which was made to bring the facility into compliance with EPA's recent regulations, including the Cross State Air Pollution Rule and the Mercury Air Toxics Standards finalized in 2012,[2] and to repay its bondholders and investors. This outcome threatens the continued operation of the plant, the jobs both at the plant and throughout the Commonwealth, affordable electricity, and economic opportunities the station provides the local community.

But you don't have to take my word for it. Under EPA's "Option 1," described as the "State" approach, EPA's IPM model forecasts Homer City's Unit 1 retiring in 2020 and Unit 2 in 2025. That puts not only Homer City's investors in jeopardy, but also the community that relies on Homer City for jobs, affordable power and economic development.

- Capacity factors for Homer City by unit in IPM modeling under various scenarios:
  - Note that in all scenarios, including base case, IPM has Homer City co-firing biomass in all units and all years

	Option 1 - State			Option 1 - Regional			Option 2 - State			Option 2 - Regional		
	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3
2016	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%
2018	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%	83%
2020	83%	-	83%	83%	78%	83%	83%	83%	83%	83%	83%	83%
2025	-	-	73%	83%	-	73%	83%	73%	81%	83%	83%	83%
2030	-	-	60%	73%	-	73%	83%	73%	83%	83%	83%	83%
2040	-	-	48%	60%	-	60%	73%	73%	73%	83%	83%	83%
2050	-	-	26%	65%	-	60%	73%	73%	73%	83%	83%	83%

- Run Years to (Actual) Years Represented Conversion:

Run Year	Years Represented
2016	2016-2017
2018	2018
2020	2019-2022
2025	2023-2027
2030	2028-2033
2040	2034-2045
2050	2046-2054

†Homer City has wet scrubber equipment installed on Unit 3, and dry scrubber equipment is being installed on Units 1 & 2. IPM shows the equipment all installed and operating.

‡IPM results found at EPA's CPP page under Power Sector Modeling. Information from RPE file in IPM results.

Now some may conclude from EPA's analysis that, under other options proposed by EPA, Homer City's units run at relatively high capacity factors, and therefore would continue to profitably generate power and revenue. But this conclusion obscures an important underlying reality. As a

[2] *National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, 77 Fed. Reg. 9,304 (Feb. 16, 2012)

merchant plant, and one that relies on a project finance model to pay for the plant's operations and investments (a point I will expand on below), Homer City must generate sufficient revenues to not only run the facility, which includes fixed, variable, and overhead costs, but also the interest and principal due to its investors and bondholders, not to the mention a rate of return on equity capital. At 70 or 80 percent capacity factors, Homer City would soon fall short of these obligations. Thus EPA's IPM model results don't offer a realistic picture of Homer City's future, which, under the Clean Power Plan, no matter which option is chosen, would be clouded by a significant risk of default and bankruptcy.

FTI's Analysis

In FTI's white paper[3] on 111(d) released earlier this year (copies of which I will make available to PADEP), we found that the costs of EPA's rulemaking will fall disproportionately on non-diversified coal-fired generators, such as Homer City.

We examined several cases of individual plants in different parts of the country, ranging from merchant and municipal coal units operating in organized, competitive markets to geographically remote rural coops. In each case examined, there is no feasible means of complying with EPA's proposal aside from carbon capture and storage technology, which has not been widely demonstrated at commercial scale, and is not yet cost-effective. These plants, then, under EPA's proposed regime, will be faced with some combination of increased costs and decreased revenues, which will likely produce one or a combination of the following outcomes:

(1) Higher electricity costs borne by their customers, often with no material reduction in CO2 emissions;
(2) Failure to recover the investment of bondholders and other creditors in electric generation-backed securities; and
(3) Reduced likelihood that investments in emission reduction technologies to comply with other EPA regulations would be recovered.

That last point is worth exploring in more detail, as some analysts, including those at EPA, have overlooked its significance. Some have assumed that investments in pollution control technology amount to "sunk costs"—in other words, a cost that has been incurred and cannot be recovered. But as we show in our paper, the capital spent installing pollution controls is far from sunk once the technology retrofit is in service. To the contrary, as I noted earlier, many of these plants, including Homer City, rely on a project financing model to raise funds needed for large-scale retrofits. This stands in contrast to entities with numerous assets that can use so-called balance sheet financing.

Simply put, with project finance, the project may be the only cash flow-producing asset an entity owns. In this case, the owner has no choice but to issue debt supported by the assets and cash flows of the project, or the revenues that can be collected from captive customers. Thus revenues from the facility must not only support material financing costs in the form of interest and principal payments over the life of the investment, but also provide an opportunity for recovery of, and return on, equity capital.

[3] *The Impact of a Fleet Emission Rate Averaging and Trading CO2 Reduction Regulation on Non-Diversified Coal Generation Entities.* Professor Bradford Cornell. FTI Consulting. (February 2014).

I should note that our white paper, completed prior to the release of EPA's proposal, examined the impacts stemming from an emissions averaging and trading regime on these particular entities. Though EPA's proposal does not specifically require averaging or trading, but instead allows states to use those mechanisms to comply with the rule, our analysis and central conclusion still holds: *EPA's proposal sets unrealistic requirements and timetables that will leave coal-dominated, non-diversified entities without meaningful, cost-effective compliance options to remain in operation.*

Homer City illustrates our conclusion. Again, Homer City's only options are purchasing credits from other lower emitting entities or to run less often. In either case, the plant's revenues will decline, and therefore its financial ability to recoup its $800 million investment in pollution controls will be significantly impaired.

Background on the Clean Power Plan

Before I proceed further, I think it's important to provide some background on the Clean Power Plan. EPA published its proposed rule in the Federal Register on June 18, 2014[4]. FTI has been analyzing the rule over the last several months. Because of its scope and reach, the proposed rule has sparked considerable debate among stakeholders, policymakers, and the general public.

The Clean Power Plan was developed pursuant to President Obama's "Climate Action Plan," released on June 25, 2013.[5] Among other things, the Climate Action Plan renewed the President's pledge to "reduce greenhouse gas emissions in the range of 17 percent below 2005 levels." To help accomplish this goal, the President simultaneously issued a Presidential memorandum[6], which directed EPA "to work expeditiously to complete carbon pollution standards for both new and existing power plants." The focus of today's hearing is on standards being developed for existing power plants.

The President's memorandum instructed EPA to do several things, including:

- Issue proposed regulations for existing power plants by no later than June 1, 2014;
- Issue final standards for existing power plants by no later than June 1, 2015; and
- Require states to submit to EPA so-called state implementation plans required under Section 111(d) by no later than June 30, 2016.

Importantly, President Obama ordered EPA to abide by several criteria in meeting these goals. The criteria include directly engaging states, given their "central role in establishing and implementing standards for existing power plants," as well as the public and leaders of affected stakeholder groups; "tailoring" regulations and guidelines to reduce costs, consistent with other rules and regulations affecting the power sector; developing approaches that allow for "regulatory flexibilities"; and ensuring that the standards are "developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses."

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[4] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34,830 (June 18, 2014)
[5] The President's Climate Action Plan, www.whitehouse.gov (June 2013.)
[6] Presidential Memorandum - - Power Sector Carbon Pollutions Standards, www.whitehouse.gov (June 25, 2013)

Consistent with the President's plan, EPA's proposal is designed to reduce power plant carbon dioxide emissions 30 percent below 2005 levels. For purposes of regulatory compliance, however, emissions and generation data from 2012 were chosen to determine each state's mandatory, enforceable emissions rate, expressed in pounds of CO2 per megawatt hour of fossil-based electric generation. The program will commence in 2020, and EPA has established an interim emissions rate requirement in 2029 (based on the average of annual emissions rates from 2020 to 2029), with a final standard slated for 2030, which will thereafter be measured according to a rolling, three-year average of emission rates.

State emission rates were established according to EPA's application of four so-called "building blocks." The four building blocks are: 1) heat rate improvements of 6 percent (relative to 2012 average rates) at existing coal-fired steam EGUs; 2) re-dispatching natural gas combined cycle power plants to a 70 percent capacity factor; 3) maintaining financially at-risk nuclear units and increasing electric generation from non-hydro renewable resources; and 4) increasing demand-side energy efficiency.

These building blocks comprise EPA's determination of what constitutes the "best system of emission reduction," or BSER, under Section 111(d)[7]. Before I move on, some background on BSER and what the CAA requires under 111(d) is in order.

BSER, 111(d) and the Clean Air Act

Section 111 of the Clean Air Act covers categories of stationary sources that may, in the EPA Administrator's judgment, cause, or contribute significantly to, air pollution "which may reasonably be anticipated to endanger public health or welfare."[8] Section 111(d) covers *existing* sources—in this case, *existing fossil fuel-fired electric generating units*.

Under Section 111(d), the EPA Administrator is required to:

> establish a procedure similar to that provided by section 110 of this title under which each State shall submit to the Administrator a plan which **(A)** establishes standards of performance for any existing source for any air pollutant **(i)** for which air quality criteria have not been issued or which is not included on a list published under section 108(a)...but **(ii)** to which a standard of performance under this section would apply if such existing source were a new source...Regulations...under this paragraph shall permit the State in applying a standard of performance to any particular source...to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

The CAA defines the term "standard of performance" as a "standard [that] reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."

EPA has elected to look "beyond the fence line" of individual EGUs to other components of the electricity system. It is my understanding that this is the first time that EPA has taken this

[7] *See* 42 U.S.C. §7411(a) and (d).
[8] CAA § 111(b); 42 U.S.C. §7411(b).

approach to establish performance standards. Apparently, requiring only unit-level reductions would not achieve the President's more ambitious emissions goals. To get more reductions, EPA has developed a "systems-based" approach that treats the entirety of the electric grid as the source category. Hence EPA's determination that BSER constitutes elements stretching from the generating plant all the way to the end-use consumer of electricity.

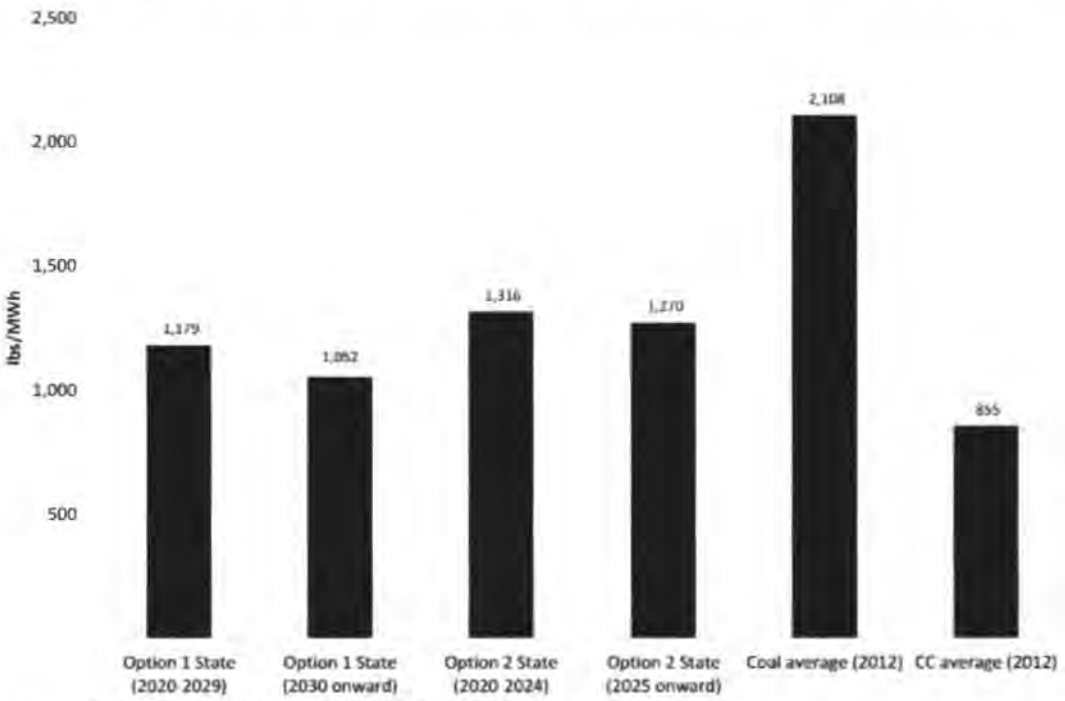
As noted above, under EPA's proposal, states are required to submit plans to EPA that demonstrate compliance with their assigned emission rates. In the preamble to the proposed rule, EPA notes that states have the flexibility to adopt any one, or all, of the four building blocks in developing compliance plans. EPA also noted that states are free to adopt other measures as appropriate, that is, beyond what EPA has defined as BSER, "provided that the state's plan achieves the required level of emission performance for affected sources."

BSER and Pennsylvania

The legality and appropriateness of a systems-based approach under 111(d) is controversial, but that is not within the scope of my testimony today. I do want to comment on how EPA's approach applies to Pennsylvania, and what it portends for some electric generating facilities in the state.

After applying all four building blocks using 2012 emissions and generation data for Pennsylvania, EPA, under "Option 1-State," calculated an emissions rate for the state in 2030 of 1,052 lbs. CO2 MWh.[9]

Figure 1: Pennsylvania Target Emission Rates and Coal and Gas CC Emission Rates



Source: Technical Support Document 20140602tsd-state-goal-data-computation_1.xlsx

[9] U.S. EPA. Agency, Office of Air and Radiation, Technical Support Document for CAA Section 111(d) Emission Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, Goal Computation Technical Support Document (June 2014).

The final goal, according to EPA, is equivalent to a 31 percent reduction in CO2 emissions from the 2012 level. Moreover, according to testimony by Eugene Trisko before the Pennsylvania Senate Environmental Resources and Energy Committee on June 27, 2014, the relative contribution of each of the four building blocks to achieving Pennsylvania's final target in 2030 is as follows:

- Coal heat rate improvements: 11 percent;
- Natural gas re-dispatch from coal units: 11 percent;
- Nuclear energy: 7 percent;
- Renewable energy: 43 percent;
- Demand-side energy efficiency: 27 percent.

EPA's proposed emission rate for Pennsylvania is not achievable by any individual coal-fired unit. The only way for the Commonwealth to comply with the emission rate is to reduce coal generation and increase generation from other sources. According to EPA's calculations, the lion's share, or about 70 percent, of eventual compliance for Pennsylvania must come from building blocks 3 and 4. Given that the Commonwealth now generates 40 percent of its electricity from coal, and that it's renewable energy potential is limited, achieving its emissions targets primarily with new renewable generation and demand-side energy efficiency will be extraordinarily difficult, and will have substantial costs ultimately borne by consumers and the state's economy.

Moreover, in calculating renewable energy potential, EPA assumes that states in a region can achieve the average of the state RPS requirements (with downward adjustments for regions that have high renewable targets). For Pennsylvania, EPA calculates a target RPS based on a simple average of the east central region states, which consists of eight states, two of which have no RPS (the EPA does not include those states in the renewable energy calculation). State renewable energy resource cost and performance options are also not considered in EPA's analysis. For example, Delaware, New Jersey and Maryland are coastal states that have excellent offshore wind potential and plan to exploit those resources. Pennsylvania, on the other hand, has limited renewable resources.

Path Forward

Disproportionate economic impacts on these facilities can be alleviated in a number of ways. Some of them were outlined in the White Paper prepared by PADEP[10]. Based in part on our review of the PADEP White Paper, we see four prudent steps that EPA could take to improve the Clean Power Plan and mitigate the impacts on plants such as Homer City:

1) EPA should establish an emissions glide path that provides more time for entities to recoup investments in pollution control equipment installed to comply with other environmental regulations.

2) EPA should adopt reasonable changes to the Clean Air Act's New Source Review program, to prevent units that make efficiency improvements under the Clean Power Plan from triggering NSR.

[10] Recommended Framework for the Section 111(d) Emissions Guidelines Addressing Carbon Dioxide Standards for Existing Fossil Fuel-Fired Power Plants. www.depweb.state.pa.us (April 10, 2014).

3) EPA should allow states to utilize flexibility found in the Clean Air Act and in EPA's regulations implementing CAA section 111(d)(1). Those provisions allow states the option of adopting different standards and compliance schedules based on "remaining useful life" and other factors, such as recent investments in pollution controls. EPA's proposal needlessly eliminates this flexibility.

4) EPA should provide states with greater flexibility to use more representative baselines to establish mandatory emission rates, and allow credit for CO2 reductions that have already been achieved.

Conclusion

Unless EPA adopts significant changes to its 111(d) proposal, and at the same time affords states the true flexibility that exists under the Clean Air Act and EPA's own regulations, a significant number of coal-fired power plants serving communities across the country, including Homer City, face the dire prospect of bankruptcy and retirement, threatening to disrupt the communities that rely on those plants.

Thank you for the opportunity to testify, and I look forward to the panel's questions.

The Impact of a Fleet Emission Rate Averaging and Trading CO_2 Reduction Regulation on Non-Diversified Coal Generation Entities

Authored by Professor Bradford Cornell

This white paper examines whether there would be disproportionate financial harm to coal-fired electric generating units ("EGUs") that are non-diversified by fuel type if the U.S. Environmental Protection Agency ("EPA") adopts greenhouse gas ("GHG") emission standards for existing sources under Section 111(d) of the Clean Air Act based on emissions averaging and trading. It is important to assess the impact because nearly 12 percent (40 gigawatts) of coal-fired U.S. generating capacity is non-diversified by coal type. Our analysis finds that an emission rate averaging and trading approach would disproportionately harm certain rural electric cooperatives, municipal electric utilities, and merchant generators for two reasons: (1) as the EPA itself recognizes, there are no viable retrofit technologies to reduce GHG emissions from existing fossil-fuel fired EGUs; and (2) there are no or limited averaging opportunities for non-diversified EGUs. As a result, an emission rate averaging regulatory approach likely would materially increase retail electricity rates and defaults on bond covenants, and reduce the likelihood that investments in other emission reductions technologies would be recovered.

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I. EXECUTIVE SUMMARY

This white paper examines whether there would be disproportionate financial harm to coal-fired electric generating units ("EGUs") that are not diversified by fuel type if the U.S. Environmental Protection Agency ("EPA") adopts greenhouse gas ("GHG") emission standards for existing sources under Section 111(d) of the Clean Air Act based on emission rate averaging and trading. It is important to assess the impact because nearly 12 percent (40 gigawatts) of coal-fired U.S. generating capacity is non-diversified.

Our analysis finds that an emission rate averaging and trading approach would disproportionately harm certain rural electric cooperatives, municipal electric utilities, and merchant generators. This is because there are no viable retrofit technologies to reduce emission of carbon dioxide from existing fossil-fuel fired electricity generation stations, and also because non-diversified coal EGUs cannot avail themselves of averaging opportunities. As a result, an emission rate averaging regulatory approach likely would materially increase retail electricity rates and defaults on bond covenants, and reduce the likelihood that investments in other emission reductions technologies would be recovered.

Our analysis finds that an emission rate averaging and trading approach would disproportionally harm certain rural electric cooperatives, municipal electric utilities, and merchant generators.

An emissions-averaging regulatory approach would likely result in material increases in retail electricity rates, defaults on bond covenants, and reduced likelihood that investments in emission reductions technologies would be recovered.

Under an emission rate averaging system, GHG emission standards for existing EGUs would be based on an averaging of emission rates across all fuel types. Averaging and trading can be beneficial to owners of a diverse portfolio, i.e. a mixture of natural gas, renewables, and nuclear EGUs, but not to co-ops, municipalities, and merchant generators that rely exclusively or predominantly on coal.

As a result, co-ops, municipalities and merchant generators will be adversely impacted, should the EPA adopt an averaging and trading program across fuels. Furthermore, because there is no cost-effective technology that can reduce GHG emissions from existing coal-fired EGUs, such units have no choice but to reduce their output or purchase CO_2 credits from lower-emitting generators (or both).

But co-ops, municipalities and merchant generators whose portfolio of electric generating units relies exclusively or predominately on coal, are not able to offset these emissions against lower-emitting sources.

In either case, these facilities will be faced with some combination of increased costs and decreased revenues, which will likely produce one or a combination of the following outcomes:

(1) **Higher electricity costs borne by their customers, often with no material reduction in CO_2 emissions;**
(2) **Failure to recover the investment of bondholders and other creditors in electric generation-backed securities**; and
(3) **Reduced likelihood that investments in emission reduction technologies to comply with other EPA regulations would be recovered**

This white paper illustrates the financial and operational impacts of adopting an emission rate averaging and trading standard on non-diversified EGUs, based on four entities at three different carbon dioxide emission cost levels. Should the EPA adopt an averaging and trading program, our analysis indicates that:

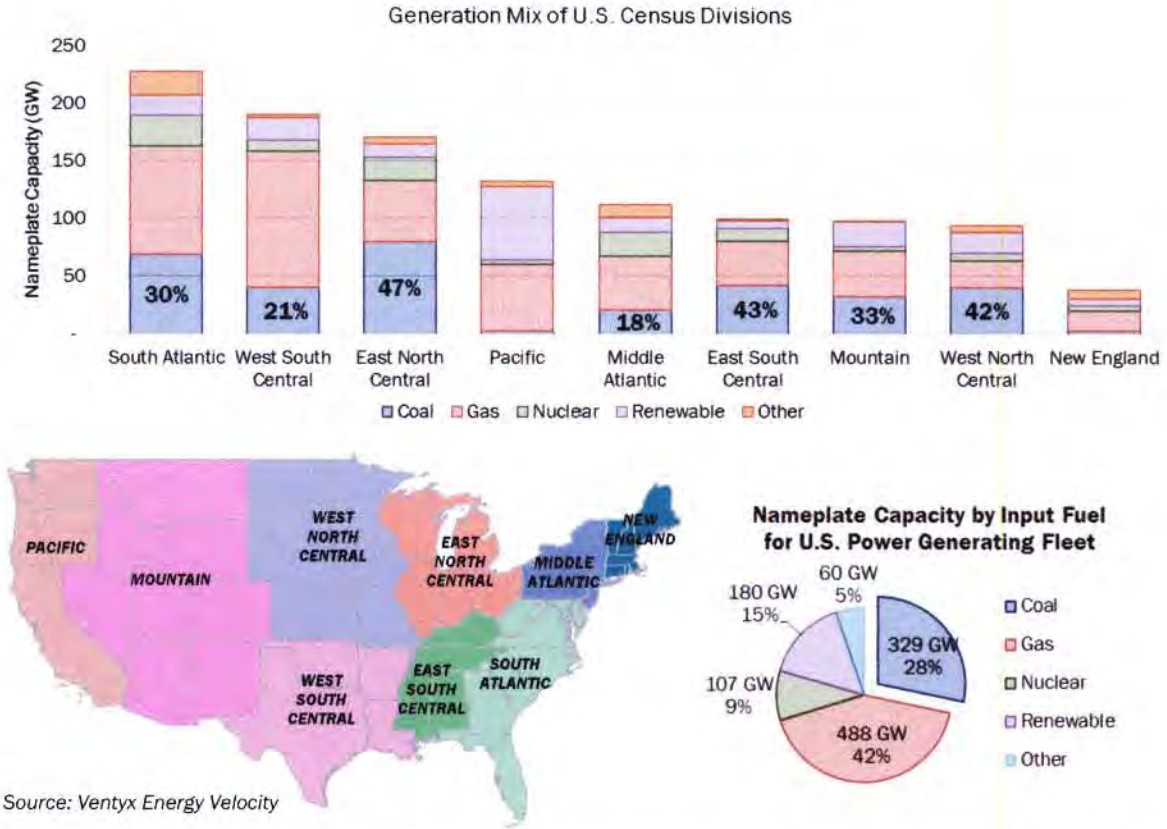
- A geographically remote rural electric cooperative (120 MW), a rural electric cooperative (1,300 MW), and a municipal electric utility (650 MW) would have to increase their rates as much as 12 percent.
- A rural electric cooperative and a municipal electric utility could be forced to back down production as much as 100 percent. For a geographically remote rural electric cooperative, however, backing down production is not an option because of a lack of alternative generation and raising retail rates remains their only course of action. Raising retail rates in lieu of backing down production would result in little or no reduction in carbon dioxide emissions while causing an increase in power prices.
- The financial viability of a mid-merit (operates approximately 50-60 percent of the time) merchant (no certainty around the energy price it receives for produced power) coal-fired plant (1,250 MW) will decline. Production could decrease by over 50 percent, contributing to an inability to fully service debt and recover investments in emissions reduction technology.
- A mid-merit, merchant, coal-fired plant that project-financed pollution control retrofits within the past five years would not be expected to generate enough cash to cover its debt service obligation.

II. INTRODUCTION

A. Fuel Mix in U.S. Electricity Generation

There are currently 1,164 gigawatts of generating capacity operating in the U.S. Coal-fired generation represents 329 gigawatts, or 28 percent, of the U.S. power generating fleet.[1] Figure 1 below illustrates how the coal-fired generating fleet is dispersed across the U.S. The highest concentration of coal-fired generating unit capacity can be found in the East North Central, East South Central, and West North Central census divisions with 47 percent, 43 percent and 42 percent, respectively.

Figure 1



Source: Ventyx Energy Velocity

Of the 329 gigawatts representing the coal-fired fleet, some 40 gigawatts (12 percent) can be considered existing, non-diversified coal-fired power plants and will likely be disproportionally impacted by an emission rate averaging approach to regulate carbon dioxide emissions from existing sources. After approximately 44 gigawatts retire by 2020[2], the aforementioned 40 gigawatts will then comprise 14 percent of the U.S. coal generation fleet.

[1] Ventyx Energy Velocity Suite "Generating Unit Capacity" database.
[2] See 2014 Annual Energy Outlook Early Release published by Energy Information Administration available at: http://www.eia.gov/forecasts/aeo/er/index.cfm

B. Environmental Regulations

Environmental regulations and air quality regulations in particular, have become increasingly stringent. Tighter environmental standards have forced many existing generation plants to balance the economic benefits of staying in business against the increasing capital investment required to ensure regulatory compliance. Air quality regulations have been a contributing factor to consolidation and have played a role in the recent spate of announced retirements of existing coal-fired plants.

Against this backdrop of more stringent environmental regulation, the EPA is beginning to formulate emission guidelines for CO_2 under Section 111(d) of the Clean Air Act ("CAA") for existing sources. It is critical to understand that controlling CO_2 emissions from power plants is different than controlling emissions of conventional pollutants, such as sulfur dioxide and nitrogen oxides. Currently, as EPA itself has recognized, there is no commercially available, cost-effective control technology for CO_2 emissions from existing fossil-fuel EGUs. The only technology under discussion, carbon capture and sequestration, is not yet commercially viable or cost-effective.[3] This stands in contrast to technologies to control conventional pollutants such as sulfur dioxides and nitrogen oxides that are commercially available and cost-effective.

Currently, as EPA itself has recognized, there is no commercially available, cost-effective control technology for CO_2 emissions from existing fossil fuel EGUs. The only technology under discussion, carbon capture and sequestration, is not yet commercially viable or cost-effective. This stands in contrast to technologies to control conventional pollutants such as sulfur dioxides and nitrogen oxides that are commercially available and cost-effective.

Commercially available and cost-effective air pollution controls have allowed electric generation owners to operate lower cost generation units and comply with air quality regulations covering conventional pollutants. In particular, to minimize the costs of supplying electricity, electric generation units are dispatched (subject to constraints) such that lower marginal cost units run ahead of higher marginal cost units. Thus, a lower marginal cost generation unit facing a new or modified regulation typically would have an opportunity to evaluate the installation of a control technology that would allow the plant to continue operating.[4] This is not the case for CO_2; as noted above, emissions control technology for CO_2 at existing generating plants is not cost- effective or commercially available.

The EPA is reviewing possible regulatory approaches for reducing CO_2 emissions from existing electric generation plants.[5] As part of its review, there has been considerable focus on improving the operational efficiency at existing generating plants, as this is currently the only direct means by which CO_2 emissions can be reduced.[6] However, efficiency improvements would result in only small emissions reductions.[7] Previous studies have proposed an approach referred to as emission rate "averaging" to achieve

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[3] DOE Press Release, "*DOE supports 18 projects to drive down costs of CCS*", Nov 10 2013 "The U.S. Department of Energy has selected 18 projects to research innovative, second-generation technologies that will help improve the efficiency and drive down costs of carbon capture processes for new and existing coal-fired power plants. $84 million in investments from the Energy Department – and additional cost-share from industry, universities, and other research institutions – will support the development of advanced technologies that will help enable efficient, cost-effective application of carbon capture and storage processes for new and existing coal-fired power plants. Projects will conduct carbon capture research for two different fossil power generation processes. For traditional, combustion-based power plants – like most coal-fired plants today – research will focus on more efficiently capturing carbon dioxide emissions post combustion. More advanced, gasification-based electric power plants break down coal - or almost any carbon-based feedstock – into its chemical constituents before any combustion takes place. Research into this technology will improve the efficiency and cost-effectiveness of pre-combustion carbon capture", available at: http://energy.gov/articles/energy-department-invests-drive-down-costs-carbon-capture-support-reductions-greenhouse-gas.

[4] Notably, EGUs that have recently made investments in pollution control equipment may find that the usefulness of these investments is threatened by potential fleet wide averaging and trading regulations.

[5] See, for example, Technical Support Document for the Advanced Notice of Proposed Rulemaking for Greenhouse Gases; Stationary Sources Section VII, Environmental Protection Agency, June 2008 pp. 15-18.

[6] The studies also often investigate the possibility of fuel mixing, however the effectiveness of this approach varies considerably and it is not seen as a significant source of emissions reduction (Id.).

[7] See, for example, Coal-Fired Power Plant Heat Rate Reductions, SL-009597, Final Report, January 22, 2009, Project 12301-001, Sargent & Lundy.

additional CO_2 emissions reductions. An emissions rate averaging approach would allow calculation of a portfolio-wide average emission rate to demonstrate compliance. Thus, owners of large, diversified generating fleets will have the flexibility to average the emission rates from their coal-fired plants with that of their lower-emitting plants, i.e. natural gas-fired and possibly renewable plants. It would then be this "fleet average" emission rate that would be assessed against the performance standard.

C. Previous Studies Analyzing Fleet Averaging

Several reports have been published discussing the potential benefits of a fleet emission rate averaging approach. Table 1 below outlines three of these reports, authored by Resources For the Future ("RFF")[8], Natural Resources Defense Council ("NRDC")[9] and M.J. Bradley & Associates ("M.J. Bradley"). Both the NRDC and RFF Reports examine the benefits of a proposed regulatory framework while the M.J. Bradley report is a discussion paper that provides background on the requirements outlined in the CAA and examines the potential form of a standard under the CAA for existing stationary sources.[10]

Table 1

Recent Reports Assessing Fleet Averaging to Reduce CO_2 Emissions from Power Generation Sources

Policy Report	Proposed Framework	Fleet Averaging	Financing Cost Assumptions
RFF	No	Yes	*No additional costs included*
NRDC	Yes	Yes	*No additional costs included*
M.J. Bradley	Three approaches analyzed:		*Not covered*
	(1) Performance standard with limited or no flexibility	No	
	(2) Performance standard with flexibility	Yes	
	(3) State budget approach	Yes	

The RFF and NRDC reports, which analyze proposed regulatory policies that the EPA could consider, fail to consider the disproportionate financial impact (i.e., increased costs and decreased revenues) that their regulatory approaches would have on entities that rely heavily on coal-fired electric generation.

This report examines the financial impact of pending CO_2 regulations on existing, non-diversified, coal-fired entities.[11] We begin by providing industry background in Part III. Part IV sets out the methodology. Part V presents and discusses our findings and Part VI concludes the report.

The RFF and NRDC reports, which analyze proposed regulatory policies that the EPA could consider, fail to consider the disproportionate financial impact that their regulatory approaches would have on entities that rely heavily on coal-fired electric generation.

[8] Burtraw, D. and Woerman, M., Technology Flexibility and Stringency for Greenhouse Gas Regulations, Discussion Paper, July 2013, Resources for the Future, RFF DP 13-24, ("RFF report").

[9] See Lashof et al., Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters, NRDC, March 2013, R: 12-11-A, ("NRDC report").

[10] M.J. Bradley & Associates, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Power Plants", October 2013, pp. 4, ("M.J. Bradley report").

[11] Note that the financial impact of a "flexible emission rate averaging and trading" approach described herein will be similar to that expected under a under a "cap and trade" regulatory regime.

III. INDUSTRY BACKGROUND

A. Financing Power Investments

Investors in EGUs generally have the ability to finance investments either on the strength of its corporate balance sheet or through project finance vehicles. Which financing path to pursue is dependent on several factors, including size of the investment, an entity's cash position, uncertainty of project cash flows and the risk profile of the project relative to other competing uses for capital and capital market trends.

Recently, investments in electric power generation coal-fired plants have taken the form of environmental retrofits installed to reduce emission of pollutants in compliance with Mercury and Air Toxics Standards ("MATS") and other EPA regulations. According to the Energy Information Administration ("EIA"), between 2007 and 2011, owners of approximately 110 coal-fired power plants invested more than $30 billion in flue gas desulfurization ("FGD") systems, representing a little less than 60 percent of the coal-fired, steam-electric generating capacity in the U.S.[12]

Between 2007 and 2011, owners of approximately 110 coal-fired power plants invested more than $30 billion in flue gas desulfurization ("FGD") systems, representing a little less than 60 percent of the coal-fired, steam-electric generating capacity in the U.S.

a. Balance Sheet Financing

When using "balance sheet" or cash flow financing, the cost of debt issuances is predicated largely on certainty of cash flows associated with the assets supporting the issuance. Debt supported by a portfolio of cash flow streams, with diverse market and segment exposure, helps to improve a lender's confidence in repayment. Companies with a diversified portfolio of assets and business lines that produce stable cash flows have the ability to raise capital at attractive rates, supported by the company's cash flows; as opposed to those investments solely supported by the project itself (assuming the company's creditworthiness is better than the project under consideration). But even balance sheet financing at the corporate level does not mean that single cash-producing assets within that portfolio can be considered debt-free. Any profitable assets within the corporate portfolio are expected to contribute to meeting the corporate debt burden.

Balance sheet corporate financing alone does not ensure certainty of debt repayment. A smaller entity, such as an electric cooperative, with a high proportion of cash flows sourced from a single industry, asset, or market may be unable to mitigate repayment or default risk by leveraging its balance sheet, compared to financing a project on a stand-alone basis. Thus, even entities with the ability to balance-sheet finance often seek alternative financing methods, dependent upon the type, size and associated risks of the investment.

b. Project Financing

Although balance sheet financing is often used by larger, diversified entities, the "project finance" approach is attractive to a variety of entities for several reasons. First and foremost, project financing is generally the most cost-effective alternative for most entities. This is largely a result of the financing obligations being tied to collateral in the form of the power plant(s) themselves. Secondly, the project may be the only cash flow producing asset an entity owns. In this case, the owner has no choice but to issue debt supported by the assets and cash flows of the project, or the revenues that can be collected from captive customers. Third, a company may decide that the investment, while sound from a strategic perspective, has a very different risk profile than the portfolio of assets currently on its balance sheet, and, as such, financially isolate it from the rest of its portfolio. Aggregating an asset with a different risk or cash flow profile typically leads to a review by credit agencies, and based on the new credit metrics, the credit

[12] See EIA report titled "Electricity Monthly Update", released on March 22, 2013 available at: http://www.eia.gov/electricity/monthly/update/archive/march2013/ . The FGD technology is a common way for coal-fired power plants to reduce their SO_2 emissions in order to comply with environmental regulations.

rating may be adjusted to reflect the new mix of risk. The credit quality of a company is vital to its ability to secure favorable project debt-financing terms, both interest paid and duration. The lower a company's credit rating, the higher the cost and shorter the duration of its debt. Finally, cash rich projects have the ability to support high amounts of leverage, provided strict covenants are in place to protect the lenders' interest. Levering a project at debt levels higher than would otherwise be possible under corporate financing can offer higher returns to equity investors. The caution with project financing is that, by definition, the bondholders hold recourse against the project and payment of debt service must be solely supported by cash flows from the project.

To ensure a level of investment protection, bondholders will often require a set of covenants meant to guard against payment default. Examples of common terms may include, but are not limited to: a cash sweep, a minimum interest or debt service coverage ratio, maintenance of a debt service reserve, or a restriction against issuing additional debt backed by the cash flows of the project. In the event a default does occur, a project may be faced with a number of negative consequences including: litigious or consensual restructuring, foreclosing on equity with bondholders taking ownership of the asset, and in some cases, bankruptcy.

Beyond the repayment of debt obligations, in most cases some portion of the total investment is funded by equity holders that expect recovery of invested capital and a return on their investment. While often not guaranteed, the required return is higher than that of debt holders' as a means of compensating for the additional cash flow risk. As an example, EPA's Integrated Planning Model ("IPM") model assumes a return on equity parameter for an independent power producer ("IPP") of 15.2 percent.[13]

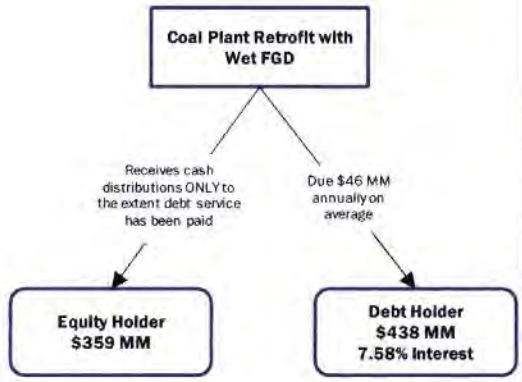
[13] See chapter 8 of EPA's IPM documentation (see Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, United States Environmental Protection Agency, EPA #430R10010, August 2010, available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.

Consider the example illustrated in Figure 2. This shows the impact project financing can have on investment decisions; a 1,500 MW coal plant finances a flue-gas desulfurization (FGD) system.

Figure 2

$ Millions, unless noted

Retrofit Investment[1]:	$797
Debt-to-Capital[2]:	55%
Debt Investment:	$438
Interest Rate[2]:	7.58%
Debt Life (years) [2]:	15
Annual Amortization Rate[3]:	6.67%
Average Annual Debt Service	
Repayment of Principal:	$29.2
Interest Charge:	16.6
Total Debt Service	**$45.8**



Illustrative Production Levels[4]	Production (GWh)	Debt Service Required Recovery (per MWh)
40% Capacity Factor	5,256	$9
60% Capacity Factor	7,884	$6
80% Capacity Factor	10,512	$4

Notes:

(1) Assumes installation of a wet flue gas desulfurization system at a cost of $531/kW for a 1,500 MW coal plant. Capital cost rate sourced from EPA IPM model documentation dated March 2013, Attachment 5-1

(2) Financing assumptions per EPA IPM model v.5.13 documentation, pages 8-10, 8-11, 8-14

(3) Debt assumed to amortize evenly over the 15 year debt life

(4) Annual production assuming 1,500 MW coal plant and 8760 hours in a year

a) The plant owner would be required to pay on average $46 million annually in debt service before cash distributions to equity.

b) The coal-fired plant owner would require between $4-9/MWh of operating margin from its wholesale market sales just to cover the cost of debt service.

The capital spent installing an FGD system is far from sunk once the retrofit is in service. To the contrary, revenues from the facility must not only support material financing costs in the form of interest and principal payments over the life of the investment but also provide an opportunity for recovery of, and return on, equity capital.

B. Approaches to Implementing CO_2 Standards for Existing Power Plants

Under Section 111 of the CAA, EPA has been directed to develop carbon emission standards for the electric power sector. Section 111(b) applies to either new or modified sources, while Section 111(d) details a process by which EPA develops emissions guidelines for states, which are then required to submit plans to EPA which establish "standards of performance" for existing generating plants. This section focuses on Section 111(d).

The M.J. Bradley report published in October 2013 evaluates the merits of several approaches in some detail.[14] In particular, three basic options are considered:

a) performance standard with limited or no flexibility,

b) performance standard with flexibility, and

c) State budget approach.

[14] M.J. Bradley & Associates, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Power Plants", October 2013, pp. 11-20.

While option (a) offers limited flexibility in meeting compliance standards, both options (b) and (c) offer flexibility in the form of potential "fleet emission rate averaging and trading" approaches.

Recently published regulatory proposals have suggested flexible performance standard frameworks that include fleet emission rate averaging and an ability to trade emission rate credits to lower overall compliance costs. For example, the RFF report assumes the adoption of a tradable performance standard where a tradable emission rate is established to reduce the fleet-wide emissions of coal-fired power plants. Similarly, the NRDC report indicates that its analysis solves for a CO_2 credit price, "implicitly assuming that some units are sellers of pollution credits and others are buyers."[15] Thus, the NRDC report appears to assume CO_2 emission credit trading in order to minimize projected compliance costs.

However, reports published to date fail to consider the disproportionate financial impact (i.e., increased costs and decreased revenues) their regulatory approaches would have on entities that rely heavily on coal-fired electric generation.

If a fleet emission rate averaging and trading approach is adopted by EPA, it would disproportionately and adversely impact the financing structures of certain rural electric cooperatives, municipal utilities and non-diversified merchant generators.

IV. Analytical Methodology

For each of the industry business cases analyzed, an estimate of the magnitude of the financial impact of a flexible carbon dioxide emission rate averaging approach on coal-dominated portfolios is developed for a multi-year period based on a mixture of historical and future operational and market data. The intention of this analysis is not to develop precise projections of future power prices, generating unit costs and production levels, but instead to demonstrate the disproportionate impact that will result for EGUs within a coal-dominated portfolio owned by cooperatives, municipal utilities, and merchant generating plant owners. The analytical approach used to estimate these financial impacts is described below.

A. Quantification of the Implied Cost of Flexible Emissions Rate Averaging

The first step in the analysis is to develop a reasonable estimate of the range of abatement costs that a flexible CO_2 emission standard will impose upon coal-fired generating units.[16] Because the adoption of an existing generating unit CO_2 emission standard will depend upon future EPA actions and the submission of individual state implementation plans, it is impossible *ex ante* to make a state-by-state assessment of the costs of compliance. However, it is possible to look at the results of recent emission standard policy analyses to establish a reasonable range of estimated compliance costs. These estimates of CO_2 compliance costs are used as a basis for estimating the compliance costs incurred by electric generators.[17]

In our analysis, we apply a range of abatement costs consistent with the findings in the RFF report to estimate the compliance costs existing coal-fired generators would incur under a standard incorporating trading.[18] RFF's existing generating unit CO_2 compliance cost estimates are developed assuming that CO_2

[15] NRDC report, pp. 22. Moreover, the NRDC report indicates that it evaluates the introduction of CO_2 emission standards by modeling region, implying trading across the five geographic regions of the United States analyzed in the report (NRDC report pp. 19 and 51).

[16] The term abatement cost refers to the dollar per short ton of CO_2 emitted that a coal generator will have to pay in order to purchase the emissions reduction credits it will require to meet the performance standard. Under a flexible performance standard framework these credits will be traded among those generators that create them by being able to meet the standard and those generators that do not meet the standard and need to purchase the credits. These costs will be incorporated into the marginal costs that generating units calculate to determine whether or not it is profitable to operate day-to-day.

[17] Note again that the financial impact of a "flexible emission rate averaging and trading" approach described herein will be similar to that expected under a "cap and trade" regulatory regime.

[18] RFF report, pp. 19. Note that the NRDC report does not provide a similar measure, but instead indicates that its analyses implicitly assume trading by solving for a credit price (NRDC report, pp. 22). However, the estimated CO_2 emissions reductions reported in the NRDC

emission credit trading can occur among electric generators. These cost estimates provide a sound basis for establishing a compliance cost range to consider when making an estimate of the financial impact on coal-dominant EGUs. For this analysis these estimated compliance costs are assumed to be $5, $10 and $15/short ton CO_2 emitted.

These values are within the range reported in the RFF report and are reasonable when compared to other analyses that have sought to estimate U.S. CO_2 emission compliance costs.[19] The lower end of the cost range would represent instances where it is feasible to meet standards at low cost; conversely the high end of the range implies difficulty meeting the standards and thus higher abatement costs.

Next, once the estimated compliance costs are identified, it is necessary to assess how these costs will be borne by generation plant owners. Because the imposition of tradable CO_2 emission standards such as those described in the NRDC and RFF reports envision a flexible compliance framework across regions of the U.S., differences in regulatory approaches will affect how electric generation plant owners, and ultimately electricity consumers, bear the costs of compliance. In this analysis two different ownership structures, an electric cooperative/municipal and a project financed merchant generating plant, are evaluated when considering how compliance costs will be borne by resource owners. In one instance it is assumed that a vertically integrated (generation, transmission and distribution) entity (e.g., the cooperative or municipal) bears the costs and that the increased costs create the need for increased revenues, which must be collected through retail and/or wholesale rate increases.[20] In the second instance, it is assumed that a wholesale electric generator that relies on wholesale electricity markets directly bears the costs with no direct means of recovering those costs.

In both cases it is necessary to consider carefully how compliance costs will affect generator plant dispatch, and the extent to which these compliance costs may be reflected in higher wholesale market prices. In the case of a vertically integrated industry participant, the increased costs will potentially reduce production, with all costs being passed through to wholesale/retail consumers. In the case of a generator selling in wholesale markets, costs increase without a commensurate increase in market prices and production is likely to decline, leading to significantly lower financial operating margins.

B. Financial Impact Analysis Framework

The financial analysis is structured to present straightforward business case examples, which show the impact that a flexible CO_2 emission rate averaging approach will have on coal-dominated entities owned by cooperatives, municipal utilities, and merchant generating plant owners. For each business case analyzed, a hypothetical operating cash-flow analysis is developed, which estimates the impact of the CO_2 emission standards over the first five years following their implementation.

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report are greater than those presented in the RFF report (NRDC report, pp. 25 and 74), and imply an abatement cost which presumably is in the range presented in the RFF report.

[19] Numerous studies seek to investigate and estimate the cost of compliance with potential CO_2 emission reductions assuming the use of CO_2 allowance cap and trade systems. It is often the case that these analyses estimate compliance costs of $25-$50/short ton CO_2 emitted (See, for example, Energy Market and Economic Impacts of the American Power Act of 2010, U. S. Energy Information Administration, July 2010, SR/OIAF/2010-01). However, preliminary estimated compliance costs for tradable credit systems have been lower and this analysis uses these relatively lower values.

[20] For purposes of this white paper, "vertically integrated entity" is defined as an entity that both owns electric generation and is classified as a load serving entity ("LSE").

FTI has chosen the following scenarios through which to illustrate the financial impact of a fleet emission rate averaging and trading approach:

Table 2

Summary of Evaluated Scenarios and the Impacts of a Market-Based Compliance Approach

			Effect of Market-Based Compliance Approach		
No.	Description	Nameplate Capacity (MW)	Back Down Production	Increase Rates	Increase in Operating Costs
#1	Remote Electric Cooperative	120	No	Yes	Yes
#2	Electric Cooperative in an Organized Market	1,300	Yes	Yes	Yes
#3	Municipal Electric Utility in an Organized Market	650	Yes	Yes	Yes
#4	Mid-Merit Merchant Coal Plant in an Organized Market	1,250	Yes	n/a	Yes

Note: For the purpose of this white paper, Scenario #4 assumes the entity has no long-term offtake contract or forward power sales to third parties. However it should be noted that some merchant generators have long-term fixed price offtake contracts that offer little or no ability to pass through environmental compliance costs.

For the scenarios outlined in Table 2, the following assumptions were made for purposes of this analysis:

a) Baseline generation was determined by analyzing the three-year average monthly peak/off peak production for similarly situated plants or entities.[21]

b) Fuel costs, variable operations and maintenance costs, and fixed costs are determined using plant-specific historical data from the past three years for similarly situated plants or entities.

c) Wholesale market power prices are calculated for peak/off-peak blocks using historical nodal-specific data from the past year in coal-dominant organized markets.

d) Residential retail electricity rates have been determined by referencing recent regulatory tariff filings for similarly situated entities.

e) Debt service costs are derived using a combination of EPA IPM modeling as well as financial disclosures of entities with similar characteristics.

These data are then used along with the range of estimated CO_2 emission standard costs to test the financial impact on the identified generation portfolios, holding all else equal.

As described above, three different scenarios are examined for each business case where flexible CO_2 emission standards are assumed to increase generating plant operational costs $5, $10 and $15/short ton of CO_2 emitted.[22] For each of these scenarios, the increased costs for the particular generating plants are calculated based on the generating unit CO_2 emission rates—and it is assumed that opportunities to lower emission rates through efficiency improvements are limited.[23] In this analysis these increased costs

[21] Generation unit production is not assumed to change materially in the no CO_2 emission standard case given the relatively short time horizon for the analysis and the fact that non-material changes in the assumed production would not change the results.

[22] The operational cost impacts are converted to $/MWh using generating unit CO_2 emission rates. For example, a generator that emits 2,100 lb CO_2/MWh incurs a cost of ($5/short ton*1 short ton/2000 lb*2,100 lb CO_2/MWh), which is $5.25/MWh.

[23] Although unit efficiency improvements can reduce compliance costs, at the margin capital investments to improve efficiency will be analyzed against purchasing rights to emit causing the cost impacts to be comparable.

represent the costs incurred to purchase credits from lower emitting generation plants in order to meet the standard, and are simulated as an increase in cost incurred to produce energy.[24]

The impact of the cost increases will affect entities differently depending upon the geographic region in which they are located. For generating units outside of organized markets, such as a coal-dominant cooperative, the ability to offset costs by purchasing power from other types of resources is likely negligible. In this instance, the generation owner will not be able to reduce production and its CO_2 emissions will continue at levels above the standard. Instead, costs associated with credit purchases will increase as units must maintain production levels to meet load obligations, with no option but to pass through these incremental costs to ratepayers.

The financial impact on EGUs located in an organized wholesale electricity market will be a combination of lower revenues associated with lower production and lower earnings associated with higher costs not being offset by higher sales revenues.

In those cases where a generating unit is in a geographic region within an organized wholesale electricity market region, the increased cost is likely to reduce plant production to the extent that alternative lower emitting sources of production are less expensive and hence will operate at higher utilization rates. Thus, the financial impact on the generating unit will be a combination of lower revenues associated with lower production and lower earnings associated with higher costs not being offset by higher sales revenues. As CO_2 emission standard compliance costs increase, reductions in production will increase. These increased costs are either (1) borne directly by ratepayers, in the case of a cooperative or municipal; or (2) result in decreased financial operating margins, in the case of a generator dependent solely on the wholesale market for revenues.

These financial impacts are illustrated using a monthly analysis which tests the likely month-by-month impacts of a CO_2 emission standard. In the analysis a baseline monthly estimate of coal-fired generating plant production is established for each business case using historical data for similarly situated generators. The implementation of the standard will result in increased costs for coal-fired generators and decreased costs for gas-fired generators.[25] Thus, the analysis next evaluates the likelihood that gas-fired generators, whose marginal costs decrease due to CO_2 emission credit revenues, will be dispatched more often.[26]

For example, in the mid-Western and mid-Atlantic regions of the U.S., gas-fired generators often do not operate at night (off-peak), as coal-fired generators are less expensive.[27] However, as the marginal costs of coal-fired generators increase relative to the marginal costs of gas-fired generating units, gas-fired generating units can be expected to displace coal-fired generating units, with coal-fired generating units generating less of the time than they otherwise would–that is, after the implementation of the emission rate standard, coal-fired units will become less competitive than gas-fired units.

This displacement can be expected to affect electricity prices; however, absent detailed modeling, it is difficult to project the precise impact. In this analysis it is assumed that gas-fired units operate more often during night-time hours, with electricity prices being unaffected. During the day-time hours, it is assumed

[24] The exact imposition of costs borne to comply with a CO_2 emission standard will vary depending upon the construction of the regulatory standard. However, pending policy proposals emphasize flexible standards implying that compliance will involve evaluating the marginal cost of abatement and making compliance decisions based on these costs. Because power production decisions are based on the costs incurred at the margin to generate electricity, it is expected CO_2 emission standard compliance costs will be evaluated as part of a generating units' marginal costs.

[25] It is assumed that the standard applies to only fossil fuel electric generators.

[26] Electric generators are dispatched hour-to-hour (often over 5 minute intervals) by system operators, subject to reliability constraints, from lowest to highest marginal cost. This "merit order" dispatch minimizes the costs of meeting consumers' power demand and establishes the marginal cost of last generating unit dispatched which sets electricity prices in organized markets.

[27] See the 2012 MISO State of the Market report prepared by Potomac Economics, available at: http://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf, and the 2012 PJM State of the Market report prepared by Monitoring Analytics, available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtm.

that coal-fired plants, now running less often, will set electricity prices such that the cost increases associated with meeting the CO_2 emission standard push up wholesale power prices.[28]

A generating plant will not operate when its marginal costs exceed the cost of electricity. Thus, to the extent a coal-fired plant's costs are driven higher than electricity prices after the implementation of the CO_2 emission standard, the coal-fired plant will not operate as frequently. Moreover, in this analysis the (conservatively) estimated impact includes a modest increase in day-time electricity prices. That is, if electricity prices decline considerably as a result of the lower costs of gas-fired generators, the impact on coal-fired generators will be even more pronounced.[29]

[28] Coal-fired units become the last generating unit dispatched to meet demand.

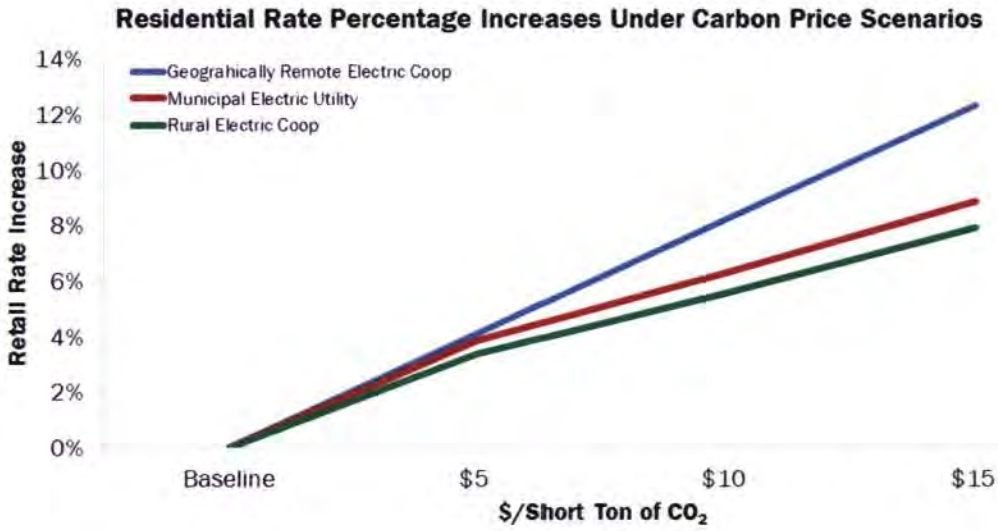
[29] In particular, it is instructive to consider the type of impact higher compliance costs (i.e., more stringent standards) would have on power markets. For a gas-fired generator more stringent standards can be expected to reduce its marginal costs by potentially half meaning that gas units would displace coal units wherever possible (given system reliability constraints). These lower costs would result in substantial reductions in electricity prices having an even greater impact on coal-fired generators. It appears that in analyses to date this decrease in electricity prices offsets the impact on power prices that is expected given the increase in coal-fired generator costs in regions without a large supply of gas-fired generators. However, recent reports are not sufficiently granular to understand the regional impacts.

V. FINDINGS

Our key findings illustrate the following impacts:

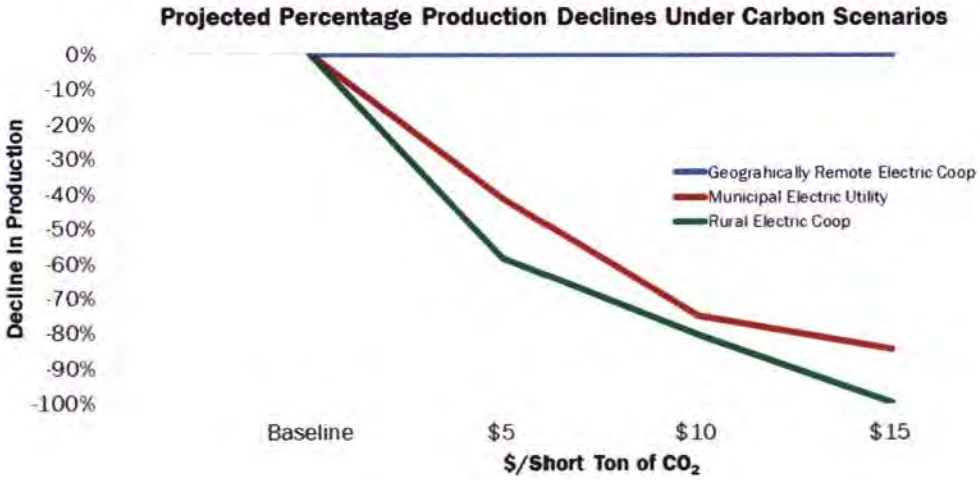
Entities that can "rate base" the costs of complying with CO_2 standards based on emissions rate averaging or trading will do so by increasing their retail rates. A geographically remote rural electric cooperative, a rural electric cooperative, and a municipal electric utility would have to increase their rates as much as 12 percent under a $15/short ton CO_2 scenario.

Figure 3



Rural cooperatives and municipal utilities located in organized markets have the option of backing down production from their coal-fired fleet and purchasing power from the wholesale market to meet load obligations. For a geographically remote rural electric cooperative, however, backing down production is not an option and raising retail rates to cover their cost increases remains their only course of action leading to increased costs to retail customers with no material reduction in carbon dioxide emissions.

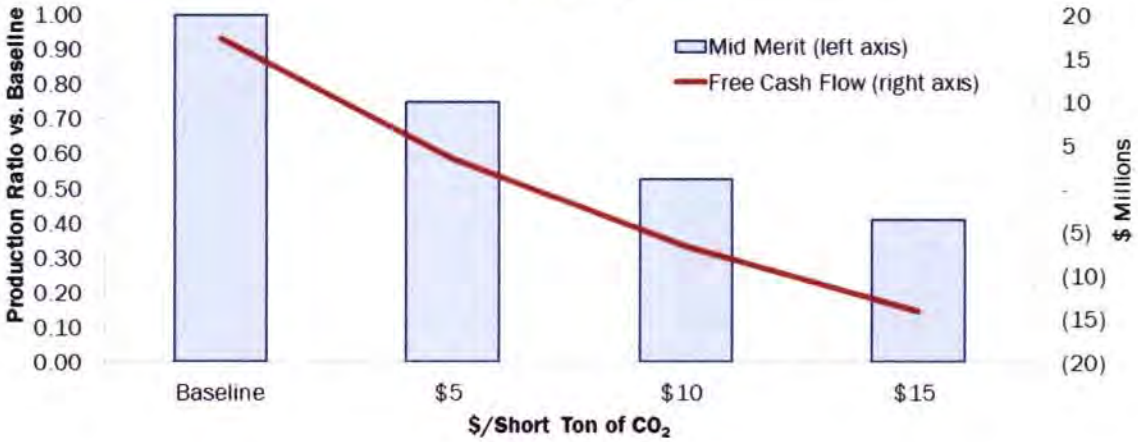
Figure 4



For a mid-merit merchant coal-fired plant operating in an organized market, backing down production is the only plausible compliance action. The reduction in production, coupled with the additional cost incurred for each megawatt hour produced leads to a significant decline in free cash flow. It should also be noted that the majority of existing coal-fired plants were financed when there was a significantly more bullish view of natural gas prices. As an example, a coal plant financed as recently as Q1 2010 would have done so when the three year Henry Hub futures curve averaged over $6/mmBtu,[30] compared to the three year average at the market close on January 2, 2014 of $4.2/mmBtu.[31]

Figure 5

Mid Merit IPP Projected Asset Production and Cashflow Under Carbon Scenarios



The financial viability of a mid-merit (operates approximately 50-60 percent of the time) merchant (no certainty around the energy price it receives for production) coal-fired plant (1,250 MW) will decline. Production could decrease by over 50 percent, contributing to an inability to fully service debt and recover investments in emissions reduction technology.

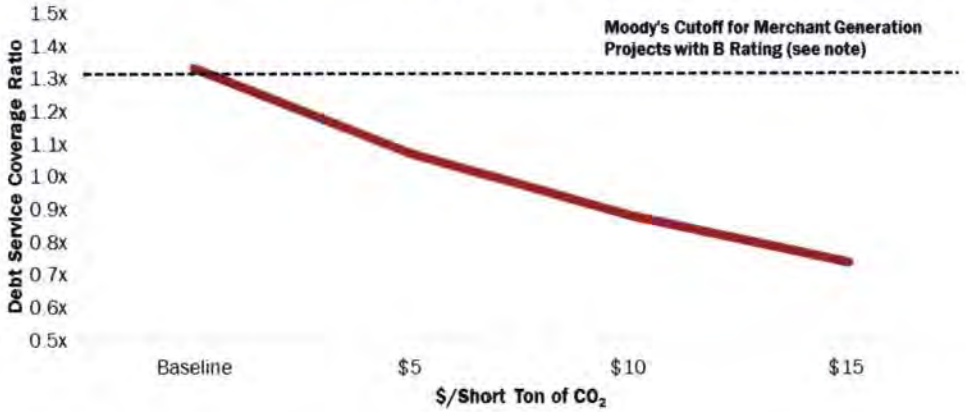
[30] See average NYMEX Henry Hub Natural Gas Futures index price of $6.41/mmBtu on January 4, 2010 for contract months from February 2010 through December 2012.

[31] See average NYMEX Henry Hub Natural Gas Futures index price of $4.20/mmBtu on January 2, 2014 for contract months from February 2014 through December 2016. It should be noted that while the drop in natural gas prices over a three year period is shown for illustrative purposes, longer term gas price projections over the same time frame show a similar downward trend.

An important implication of declining production and tightening margins is the effect on the credit metrics associated with any debt obligations. A mid-merit merchant coal-fired plant that installed and project financed retrofits within the past five years will struggle to meet debt service obligations and avoid triggering bond covenants.[32] Debt service coverage ratio ("DSCR"), or the ratio of cash available for debt service over total debt service, is a key metric used by rating agencies when evaluating the appropriate bond rating. The lower the DSCR ratio, the less likely the entity will be able to repay its debt service obligation. For example, Moody's sets a rating range of 1.3x-2.4x DSCR for 'B' rated entities.[33] For the purpose of this example, let us assume the entity's bonds are 'B' rated by Moody's; the further an entity's debt service coverage ratio falls below 1.3x, the greater the likelihood they will face a downgrade and potential bankruptcy.

Figure 6

Mid Merit Projected Debt Service Coverage Ratio Under Carbon Scenarios



Notes:

(1) Source – Moody's Investors Service "Ratings Methodology – Power Generation Projects" dated December 21, 2012, pp. 24

(2) Debt Service Coverage Ratio defined as: cash flow available before debt service / (principal + interest)

A mid-merit, merchant, coal-fired plant that project-financed pollution control retrofits within the past five years would not be expected to generate enough cash to cover its debt service obligation.

[32] For the purpose of this white paper "debt service coverage ratio" is defined as: cash flow available before debt service / (principal + interest).). Note also that this example assumes retrofits are financed in accordance with assumptions made in chapter 8 of EPA's IPM documentation (see Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, United States Environmental Protection Agency, EPA #430R10010, August 2010 available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.

[33] Moody's Investors Service "Ratings Methodology – Power Generation Projects" dated December 21, 2012, pp. 24.

As Figures 3 through 6 illustrate, coal-dominant generation portfolios will realize significant financial burdens as a result of the introduction of CO_2 emission standards. Owners of these portfolios have limited compliance options and will need to purchase the right to emit from other lower-emission generators, reduce production and purchase substitute power from other sources where feasible, and/or invest in generating unit efficiency improvements. The costs of taking any or all of these actions will lead directly to rate increases for the customers of cooperative and municipal generation owners, and threatens repayments to investors – both by defaulting on bond obligations (possibly resulting in bankruptcy), and in the case of most non-diversified generators, failing to provide a return on and of equity capital. Moreover, to the extent that power production is reduced at existing generation facilities in response to the proposed standards, significant capital investments will be "stranded" and possibly completely devalued.

The costs of taking any or all of these actions will lead directly to rate increases for the customers of cooperative and municipal generation owners, and threatens repayments to investors – both by defaulting on bond obligations (possibly resulting in bankruptcy), and in the case of most non-diversified generators, failing to provide a return on and of equity capital.

VI. CONCLUSION

Our analysis illustrates that an emission rate averaging and trading approach would disproportionately harm certain rural electric cooperatives, municipal electric utilities, and merchant generators. This is because, as the EPA itself has recognized, there are no viable technologies to reduce emissions of carbon dioxide from existing fossil-fuel fired electric generation stations, and also because non-diversified coal generators cannot avail themselves of averaging opportunities. As a result, an emissions-averaging regulatory approach would likely result in material increases in retail electricity rates, an increase in defaults on bond covenants, and reduced likelihood that investments in emission reductions technologies would be recovered.

Published reports suggesting a flexible emission rate averaging and trading approach to carbon regulation for existing sources either ignore the financial structure of coal-dominated entities altogether or consider these costs to be "sunk" costs. Both assumptions are flawed and conceal the disproportionate adverse financial impact these proposals would have on non-diversified coal-fired entities.

As the EPA contemplates CO_2 regulations on existing emission sources, it is important to consider the impacts a flexible emission rate averaging and trading approach will have on non-diversified coal-fired entities.[34] Non-diversified rural cooperatives, municipal utilities, and merchant generators will be faced with limited paths to compliance, each fraught with negative consequences. Rural and municipal utilities will be forced to raise retail rates paid by consumers and cooperatives located in organized markets will be forced to curb production. Merchant generators will be forced to curb production and, as a result, risk not only defaulting on debt obligations but may also fail to provide a return on and of capital to equity investors. Moreover, some of these compliance paths fail to achieve the primary goal of the initiative, reducing carbon dioxide emissions.

As the EPA contemplates CO_2 regulations on existing emission sources, it is important to consider the impacts a flexible emission rate averaging and trading approach will have on non-diversified coal-fired entities.

[34] I understand that the EPA should take into account all relevant costs and benefits when developing its regulation. (See, for example Chapter 9 of "EPA Guidelines for Economic Analyses", available at: http://yosemite.epa.gov/ee/epa/eed.nsf/pages/guidelines.htm.

APPENDIX

Glossary of Key Terms

Term	Definition
Bond Covenants	A legally binding term of an agreement between a bond issuer and a bond holder. Bond covenants are designed to protect the interests of both parties. Negative or restrictive covenants forbid the issuer from undertaking certain activities; positive or affirmative covenants require the issuer to meet specific requirements. *(Source: Investopedia)*
Clean Air Act ("CAA")	Legislation passed by Congress initially in 1970, with major revisions in 1977 and 1990. The CAA was designed to protect public health and welfare from different types of air pollution caused by a diverse array of pollution sources. *(Source: EPA)*
Debt Service	Any payments relating to debt obligations including interest and principal.
Debt Service Coverage Ratio ("DSCR")	Ratio of Net Operating Income to Total Debt Service.
Debt Service Reserve	Reserve established to ensure servicing of interest and principal payments associated with debt obligations in the event that there is insufficient operating cash.
Displacement	The act of one generating unit within an integrated electric system becoming more marginal cost competitive relative to another generating unit and as a result being dispatched ahead of it.
DOE	U.S. Department of Energy *(Source: DOE)*
Economic Dispatch	The allocation of demand to individual generating units on line to effect the most economical production of electricity. *(Source: NERC)*
EEI	Edison Electric Institute *(Source: EEI)*
EIA	Energy Information Administration *(Source: EIA)*
Electric Cooperative	An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Utilities Service (prior Rural Electrification Administration), U.S. Department of Agriculture. *(Source: EIA)*
Electric Generating Plant (Station)	A station that consists of electric generators and auxiliary equipment for converting mechanical, chemical, or nuclear energy into electric energy. *(Source: EIA)*
Electric Generating Unit	Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power. *(Source: EIA)*
Electric Utility Restructuring	The introduction of competition into at least the generation phase of electricity production, with a corresponding decrease in regulatory control. *(Source: EIA)*
Emissions Averaging	An approach to emission regulation by which entities are permitted to average the emissions (typically measured in pounds or tons per unit of power) of their total generating fleet for purposes of meeting a performance standard.

APPENDIX (cont.)
Glossary of Key Terms

Term	Definition
Energy Policy Act of 1992 ("EPACT")	This legislation creates a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Holding Company Act of 1935 and grants the authority to the Federal Energy Regulatory Commission to order and condition access by eligible parties to the interconnected transmission grid. *(Source: EIA)*
EPA	U.S. Environmental Protection Agency *(Source: EPA)*
FERC	Federal Energy Regulatory Commission *(Source: FERC)*
Gigawatthour ("GWh")	A measure of electricity equating to one billion watthours. *(Source: EIA)*
Load	An end-use device or customer that receives power from the electric system. *(Source: NERC)*
M.J. Bradley	M.J. Bradley & Associates *(Source: M.J. Bradley)*
Marginal costs	The additional cost that would be incurred by producing or purchasing the next available unit of electric energy above the current base cost. *(Source: EEI)*
Megawatthour ("MWh")	A measure of electricity equating to one million watthours. *(Source: EIA)*
Merchant	High-risk, high-profit facilities that operate, at least partially, at the whims of the market, as opposed to those facilities that are constructed with close cooperation of municipalities and have significant amounts of waste supply guaranteed. *(Source: EIA)*
Mid-merit (intermediate) generating plants	Generating units that provide most or all of their energy during the day when energy demand increases, generally operating between 50-60 percnet of the time. Intermediate generators can either turn off or cycle to a low minimum run level at night so they can match the diurnal demand patterns. Although some coal plants can provide this capability, it is more often gas, oil, or hydro plants that provide this service. *(Source: DOE)*
Municipality	A village town, city, county, or other political subdivision of a State. *(Source: EIA)*
NERC	North American Electric Reliabilty Corporation *(Source: NERC)*
Non-diversified coal-fired entities	Entities owning a portfolio of power generating units whereby at least 75% of portfolio's electricity is generated by coal-fired generating units.
NRDC	Natural Resources Defense Council *(Source: NRDC)*
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns; these off-peak periods differ for each individual electric utility. *(Source: EIA)*
Organized Electricity Market	An auction-based day ahead and real time wholesale market where a single entity receives offers to sell and bids to buy electric energy and/or ancillary services from multiple sellers and buyers and determines which sales and purchases are completed and at what prices, based on formal rules contained in Commission-approved tariffs, and where the prices are used by a transmission organization for establishing transmission usage charges. *(Source: Code of Federal Regulations)*
Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns; these on-peak periods differ for each individual electric utility. *(Source: EIA)*
RFF	Resources For the Future *(Source: RFF)*
Stranded Asset	Any asset that is no longer being used. *(Source: EEI)*
Vertically Integrated	Any utility that owns generation, transmission and distribution assets.

Author Biography

Bradford Cornell is a Visiting Professor of Financial Economics at Caltech and a Senior Consultant and Advisory Committee member at Compass Lexecon. He previously served as a Senior Consultant at Charles River Associates from 1999-2011. Prior to joining the Caltech faculty, Professor Cornell was the Bank of America Professor of Finance at the Anderson Graduate School of Management, University of California, Los Angeles, where he taught for 26 years. He was also the founder of FinEcon, a financial economic consulting firm that merged with CRA in 1999.

In his academic capacity, Professor Cornell has published approximately 100 peer reviewed articles on a wide variety of financial topics. He is also the author of *Corporate Valuation: Tools for Effective Appraisal and Decision Making*, published by Business One Irwin, and *The Equity Risk Premium and the Long-Run Future of the Stock Market*, published by John Wiley. Professor Cornell has served as an associate editor of numerous academic journals including *Journal of Finance, Journal of Financial Economics, Financial Analysts Journal,* and the *Journal of Portfolio Management*. He is a past Director and Vice-President of the Western Finance Association and a past Director of the American Finance Association. He has won a wide variety of awards for his research including the Graham and Dodd Award from the Financial Analysts Society in 2006 and 2010 and the Bernstein/Fabozzi Award from the Journal of Portfolio Management in 2010.

As a consultant, Professor Cornell is one of most experienced expert witnesses in the field of complex financial litigation working with Fortune 100 companies and the leading law firms that advise them as well as various agencies of the United States Government. Since 1984, Professor Cornell has provided testimony and expert analysis in many of the largest and most widely publicized finance related cases in the United States. Virtually all of the corporate matters in which Professor Cornell provided assistance involved director level decision making on issues including mergers and acquisitions, accounting and auditing, and reporting and corporate governance.

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