STEVEN L. BESHEAR
GOVERNOR

LEONARD K. PETERS
SECRETARY

ENERGY AND ENVIRONMENT CABINET
OFFICE OF THE SECRETARY
500 MERO STREET
12TH FLOOR, CAPITAL PLAZA TOWER
FRANKFORT, KY 40601
TELEPHONE: (502) 564-3350
FACSIMILE: (502) 564-3354
www.eec.ky.gov

October 22, 2013

Gina McCarthy, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Administrator McCarthy:

First, thank you and your staff for meeting with Governor Beshear and me last month to discuss several issues of mutual concern.

As you know, Kentucky has numerous problems and concerns with the EPA's proposed rule on CO_2 emissions relating to new power plants, and we will be further voicing those concerns as that process unfolds.

In regard to the upcoming proposed rule concerning existing power plants, on behalf of Governor Beshear, I am providing a white paper for discussion of compliance options under Section 111 (d) of the Clean Air Act. As you indicated during our September 19, 2013 meeting, states will be an integral part of the EPA's process to develop guidelines for the existing source rule under Section 111 (d).

A framework such as the one outlined in the attached document provides needed flexibility, and yet is an effective, equitable, and cost-effective approach. It considers the vast differences among states in their resource potential and current generation portfolio; and more importantly for states like Kentucky, it does not lead to an all-out replacement of coal-fired generation with natural gas generation, as we contend would occur under a less flexible approach.

Since President Obama's goal is to reduce carbon dioxide emissions, and not simply favor one fossil fuel over another, compliance options that take into account demand and supply-side energy efficiency and renewable and other low-carbon generation sources must be allowed. This sample framework includes these options. Furthermore, our analyses demonstrate that greater emissions reductions can occur under such a flexible, mass-emissions approach (reducing total average emissions) when compared with a rigid standard that simply places an emissions threshold of tons per unit of energy on electric generating facilities. For national energy and economic security purposes, electric generation resource diversity is crucial, and the only way to ensure such diversity while reducing emissions is to avoid a rigid target.

Kentucky is committed to reducing its greenhouse gas emissions, but we will not put our citizens and industries in the untenable position of having to forego economic prosperity to achieve these reductions. We are also committed to working with you and your staff in the coming weeks and months as you develop guidelines in advance of the June 2014 deadline. Our framework is not a formal proposal, *per se*—it is meant to guide our discussions with you and to demonstrate that we can achieve reductions to meet President Obama's goals in a meaningful manner that does not jeopardize our state's economy.

As the state most-dependent on coal-fired generation and one with the most energy-intensive manufacturing economy, Kentucky has much at stake if national policies do not take into account the variations among the states in establishing existing source guidelines. We look forward to discussing the framework we have outlined at your earliest convenience. We truly appreciate your sincerity and willingness to consider a broad array of options to meet Section 111(d) guidelines.

Sincerely yours,

L K Peters

Leonard K. Peters
Secretary

LKP:wh
Enclosure

cc: Robert Perciasepe, Deputy Administrator
US Environmental Protection Agency

Gwen Keyes-Fleming, Chief of Staff
US Environmental Protection Agency

Janet McCabe, Acting Assistant Administrator for the Office of Air and Radiation
US Environmental Protection Agency

Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act

Commonwealth of Kentucky
Energy and Environment Cabinet

October 2013

Technical Contacts

Several individuals contributed to this document; the principal authors are:
Kenya Stump, Division for Air Quality, Department for Environmental Protection; Aron Patrick, Department for Energy Development and Independence; and Karen Wilson, Energy and Environment Cabinet.

Correspondence regarding the contents of this document may be addressed to:
John Lyons
Email: John.lyons@ky.gov

TABLE OF CONTENTS

TABLES AND FIGURES

PREFACE

As a cornerstone of his Climate Action Plan, President Barack Obama has directed the U.S. Environmental Protection Agency to establish carbon dioxide emission standards for new and existing power plants. EPA has indicated it is seeking state input in developing these standards under Section 111(d) of the Clean Air Act for existing power plants. In response, Kentucky presents the following framework, developed through extensive analysis and economic modeling. This framework complies with the legal provisions of Section 111(d) while ensuring Kentucky can reduce emissions in the most cost-effective manner.

"The flexibility afforded to states under Section 111(d) is crucial to crafting greenhouse gas regulations and policies that enable strong state economies while capitalizing on diversity among the states."

By comparing two divergent approaches to an emissions reduction program—a rate-based versus a mass emissions—our analyses demonstrate why the latter is not only more effective at achieving stated goals for reducing emissions but does so in a more equitable manner considering the differences among states with their existing generating portfolios. The flexibility afforded to states under Section 111(d) is crucial to crafting greenhouse gas regulations and policies that enable strong state economies while capitalizing on diversity among the states. The framework details strategies that reduce greenhouse gas (GHG) emissions to meet the President's goals through a combination of demand-side energy efficiency and conservation, electric generating unit (EGU) process upgrades and improvements, fuel switching and EGU diversification, and carbon offsets.

Kentucky's position urging EPA to adopt a mass-emissions approach over a rate-based approach arises from a thorough analysis of how variations in states' generating portfolios, energy intensity and leading economic sectors are intricately linked. Each state and its economy are different and unique. One way of measuring these differences is through the amount of electricity required to generate a dollar of state gross domestic product (SGDP). It is intuitive that manufacturing states and those with a substantial industrial component will be higher by this measure. Consumer states without a significant manufacturing base will benefit from those energy expenditures in states with a strong manufacturing base, and these more service-oriented states will have lower state electricity generation and consumption.

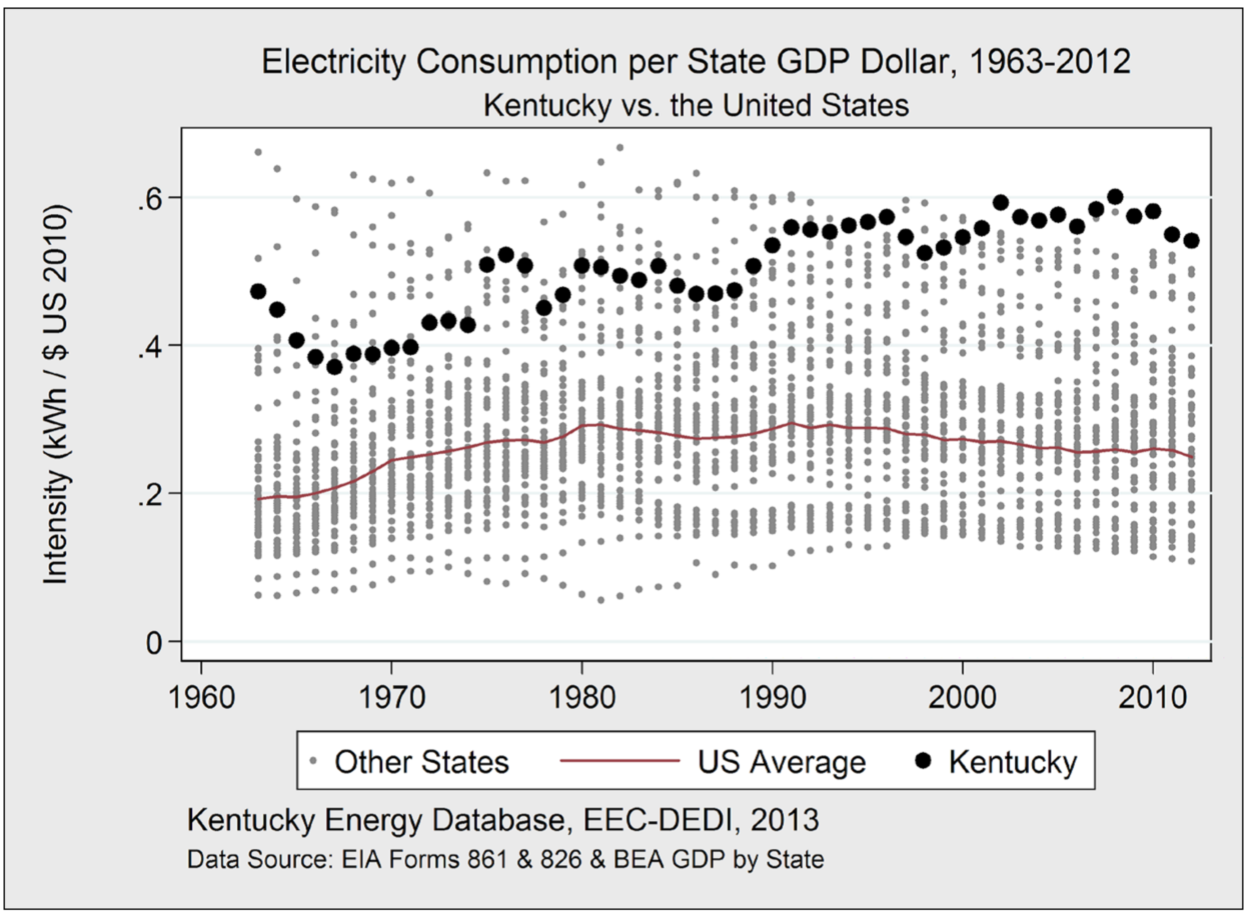
These differences among producer and consumer states have resulted from numerous historic factors, and they illustrate how states have developed based on their geographic and natural resource strengths. Kentucky is an example of this—with vast coal resources allowing for low-cost and reliable electricity and with the geographic accessibility to major population centers, energy-intensive industries have located within the state. These industries provide a large share of the manufactured products used throughout the country. A state like New York has thrived through a more service-oriented economy. Each state's strengths provide benefits nationally, and actions that are detrimental to an economic engine in one state can have negative impacts throughout the country.

Figure 1 and Table 1 (on Pages 2 and 3) show this aspect of individual state economies over several decades. In Figure 1, each dot represents the kilowatt hour per dollar of SGDP (kw-h/$SGDP) for each state in each year. This measure varies more than four-fold from the highest to the lowest. Producer states like Kentucky cluster on the high end at about 0.5 kw-h/$SGDP, while primarily consumer states like New York and California are on the low end at about 0.13 kw-h/$SGDP.

It is a likely corollary that if these producer states did not have low electricity rates there would be even less manufacturing in the U.S. today. It is incumbent that, as federal policies for greenhouse gas (GHG) emissions reductions are proposed and implemented, these differences among the states be an essential element of the discussions and deliberations. Given President Obama has stressed rejuvenating the nation's manufacturing economy, which must rely heavily on reliable, affordable electricity, these considerations align with the overall objectives of the administration.

Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive manufacturing economy in the United States, making Kentucky particularly vulnerable to future electricity price increases. A 2012 study predicted a 25 percent increase in electricity prices would be associated with a net loss of 30,000 full-time jobs, primarily in the manufacturing sector. [1] Greater increases in electricity prices would have even greater impacts on job losses.

Figure 1: Electricity Consumption per State GDP Dollar



1 Kentucky Energy and Environment Cabinet. (2012). *The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices.* Department for Energy Development and Independence, Frankfort. http://energy.ky.gov/Programs/Documents/Vulnerability%20of%20Kentucky's%20Manufacturing%20Economy.pdf

Table 1: Electricity Intensity by State, 2012

Rank	State	**Electricity Intensity** *kWh of Electricity Consumption per Real GDP*	Rank	State	**Electricity Intensity** *kWh of Electricity Consumption per Real GDP*
1	Kentucky	0.541	27	Nevada	0.277
2	Mississippi	0.503	28	Texas	0.274
3	Alabama	0.496	29	Michigan	0.274
4	West Virginia	0.468	30	Washington	0.260
5	South Carolina	0.467	31	Virginia	0.259
6	Wyoming	0.465	32	Pennsylvania	0.253
7	Arkansas	0.449	33	United States	0.249
8	Idaho	0.424	34	Oregon	0.247
9	Oklahoma	0.386	35	Minnesota	0.240
10	Indiana	0.368	36	Utah	0.240
11	Tennessee	0.368	37	Maine	0.227
12	Louisiana	0.366	38	Illinois	0.216
13	Montana	0.359	39	Vermont	0.212
14	Missouri	0.336	40	Colorado	0.207
15	North Dakota	0.334	41	Maryland	0.205
16	Georgia	0.320	42	Delaware	0.185
17	Nebraska	0.318	43	New Hampshire	0.177
18	Iowa	0.316	44	Rhode Island	0.159
19	Ohio	0.314	45	New Jersey	0.157
20	New Mexico	0.304	46	Massachusetts	0.142
21	Kansas	0.304	47	Hawaii	0.140
22	Florida	0.296	48	California	0.136
23	North Carolina	0.296	49	Connecticut	0.135
24	Arizona	0.296	50	Alaska	0.130
25	South Dakota	0.294	51	New York	0.124
26	Wisconsin	0.277	52	District of Columbia	0.108

INTRODUCTION

In developing our proposed framework, we analyzed the potential implications on Kentucky and other states for addressing carbon dioxide emissions from existing power plants using various policy options, with the assumptions that:

- Each major GHG emissions sector will contribute proportionately to any overall emissions reduction strategy.
- Greenhouse gas emissions from transportation sources will be handled through federal regulations such as Corporate Average Fuel Economy (CAFE) standards.
- Proportionate GHG emissions from other non-electric generating unit (EGU) emitting sources will be handled under other EPA-proposed regulations.
- EGU-equivalent emission reductions in Kentucky will be met through emission reductions at the source, reductions through efficiency and conservation, and carbon offsets.

"The transition to lower emission sources should not be a sole trade-off between one type of carbon fuel (coal) for another (natural gas)."

As with other landmark environmental policies, greenhouse gas regulations for the electricity generating sector will be a pivotal point for many states as they transition to cleaner sources of energy. However, the transition to lower emission sources should not be a sole trade-off between one type of carbon fuel (coal) for another (natural gas). Our proposed framework avoids such a scenario as it encompasses flexible mechanisms that ultimately favor a diverse energy portfolio that will include renewable and other low-carbon sources and energy efficiency.

Kentucky, as with many other states, is already implementing policies and programs that lead to reduced greenhouse gas emissions across sectors. These activities include a substantial emphasis on energy efficiency as it is the least-cost method for reducing emissions across end-use sectors. For example, Kentucky's stated goal of meeting 18 percent of electricity demand through energy efficiency by the year 2025 is well on target. Our proposal builds upon these activities and aligns them with Section 111(d) regulatory obligations. In addition to programs and policies, electricity market forces combined with regulations on other air emissions are moving Kentucky's generation portfolio toward reduced greenhouse gas emissions.

With these combined factors, Kentucky and many other states are positioned to achieve the President's stated greenhouse gas emission reduction goals when combined with what we urge are flexible, achievable standards through requirements for existing plants under Section 111(d). From 2005 emission levels, Kentucky's fossil fueled power plants have achieved 7 percent reductions as of 2012 (see Appendix B). A mass-emission reduction standard affords all states the maximum flexibility to use each state's unique current and future energy resources to support the economies of each state.

Clean Air Act Section 111(d)

Section 111(d) obligates EPA to prescribe regulations for a state to submit a plan to establish standards of performance for any existing sources. Under Section 111(d), EPA sets guidelines for these standards, but the states have the responsibility to apply the requirements for existing sources. States have broad flexibility to implement Section 111(d) standards; however, EPA retains approval authority and the ability to regulate if a state fails to submit a satisfactory plan. To ensure flexibility is afforded in establishing standards, Section 111(d)(1)(B) states that EPA shall allow the state to take into consideration, among other factors, the remaining useful life of the existing source when applying a standard of performance. Ultimately, the state-specific plan is submitted as a State Implementation Plan (SIP) to EPA for approval.

A key element to Section 111 is the definition for "standard of performance."

The term "standard of performance" means a standard for emissions of air pollutants which 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. (CAA Section 111(a))

"While Carbon Capture and Sequestration (CCS) technology is critical to the reduction of CO_2 levels from fossil fuel-based power plants, it is not yet commercially proven in the primary large-scale application for which it is envisioned—electric power plants fueled by coal or natural gas."

Of note are the terms "achievable" and "adequately demonstrated." For greenhouse gases under Section 111(d), any control technology requirements proposed by EPA would have to meet these conditions, and EPA would have to provide justification on why it believes technology exists to allow the sector to meet a particular standard.

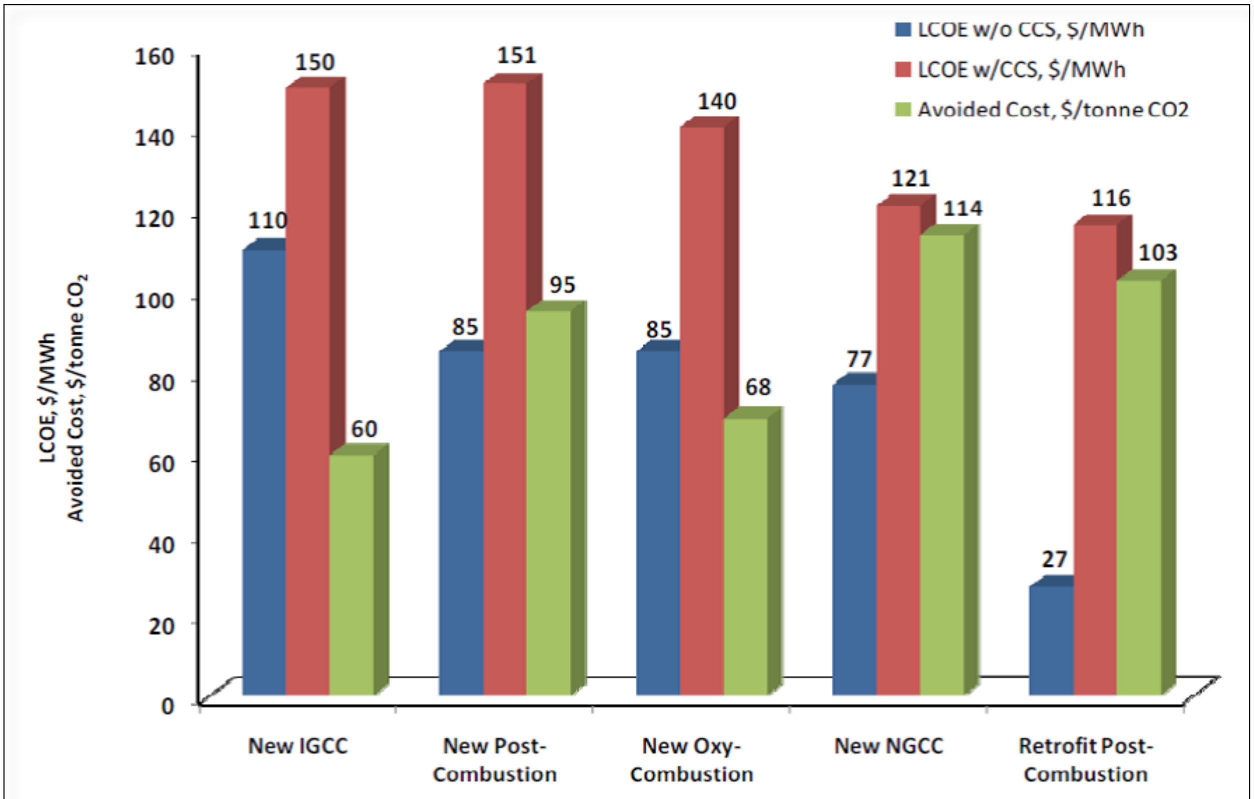
Of concern is whether the technologies to capture and sequester CO_2 from existing sources will be deemed achievable and adequately demonstrated by the EPA in establishing the Section 111(d) standards. While Carbon Capture and Sequestration (CCS) technology is critical to the reduction of CO_2 levels from fossil fuel-based power plants, it is not yet commercially proven in the primary large-scale application for which it is envisioned—electric power plants fueled by coal or natural gas. See Appendix C for the status of current carbon capture projects in the United States.

The energy requirements of current CO_2 capture systems are roughly 10 to 100 times greater than those of other environmental control systems employed at a modern electric power plant. For existing power plants, such as those in Kentucky, the feasibility and cost of retrofitting CO_2 capture systems depend heavily on site-specific factors such as the plant size, age, efficiency, type and design of existing air pollution control systems, and availability of space to accommodate a capture unit. To obtain comparable GHG emission reductions, the cost of retrofitting an existing power plant with CCS technology is higher than the cost of a new NGCC without CCS ($116 per MWh versus $77 per MWh) (Figure 2).

Rate-Based versus Mass Emissions Strategies

Traditional performance standards have been technology-based and ultimately tied to achieving the National Ambient Air Quality Standard (NAAQS) for a pollutant. In the case of CO_2 and existing coal electricity generating units, there is no NAAQS or readily available technology to guide any CO_2 performance standard. In the absence of a NAAQS, much discussion is focused on a rate-based approach, with emission levels from a natural gas combined cycle unit (which are one-half the emissions of a typical coal unit) serving as a surrogate target.

Figure 2: CCS Cost Variation Among Different Generating Sources [2]



An emission rate standard is one where the emission level is established in relationship to a raw material input or production output. An example of this approach is one where the rate-based standard is expressed as allowable CO_2 emissions per unit of electricity generation output (MW-h) as has been done with the recently proposed NSPS for new EGUs. These types of standards are in comparison to the second option of a mass-emission reduction standard. A mass-emission standard establishes a quantity or mass of pollutant to be reduced from a baseline level. Mass-emissions standards are often expressed as a percent reduction of the mass (tons) of pollutant (CO_2).

Our analyses (see details in Appendix A), using benchmarks established in the Natural Resources Defense Council's (NRDC) 2013 report Closing the Power Plant Carbon Pollution Loophole, show that Kentucky's economy would be negatively affected by a traditional rate-based emissions threshold, and more importantly, we will have not achieved the level of emissions reductions that could occur through a more flexible mass-emissions reduction strategy. Kentucky is not alone in this regard. Therefore, we urge EPA to examine the results of this analysis and consider the implications in its rulemaking for existing sources.

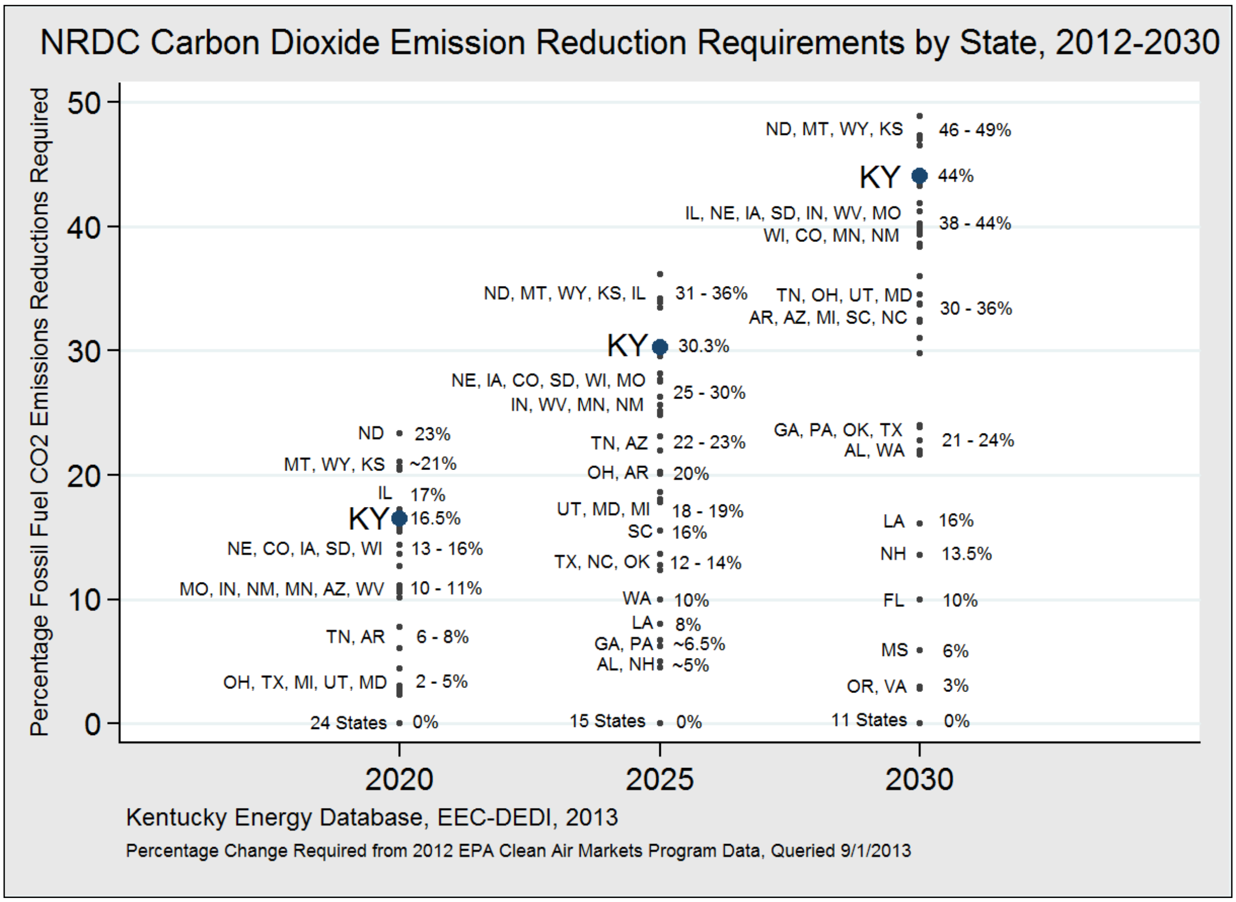
The traditional rate-based approach would likely force Kentucky's utilities to retire their coal units—which currently provide more than 90 percent of Kentucky's electricity—and build new natural gas fired generation. Kentucky would simply go from being primarily dependent on one fossil energy source (coal)

[2] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

to being primarily dependent on another fossil energy source (natural gas). The costs for ratepayers would be high, renewable and efficiency opportunities would not achieve their full potential, and the amount of greenhouse gas emission reductions achieved in the aggregate would be less than that specified by the President's goal.

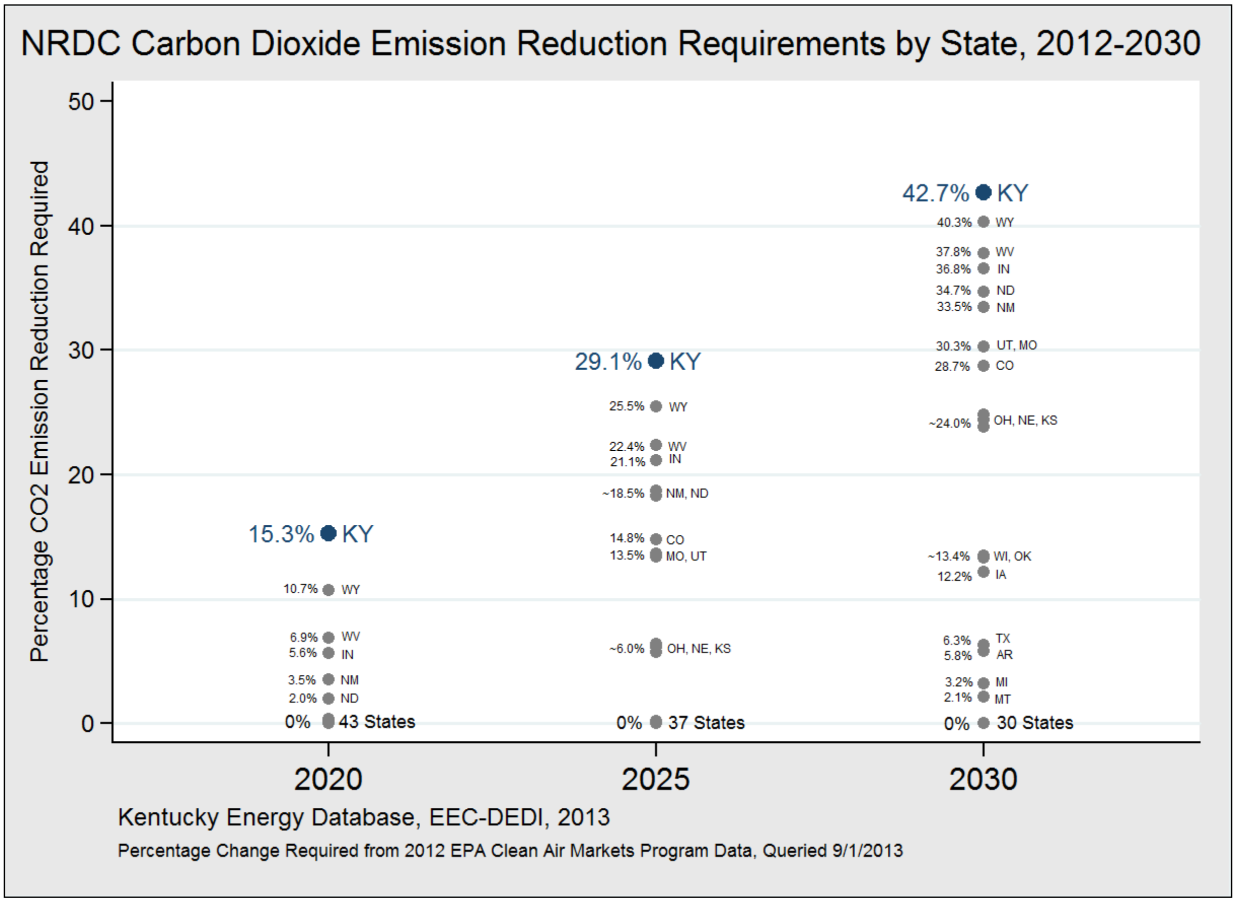
Our analyses also show that Kentucky and a few other states carry a disproportionate burden relative to other states. The charts are based on benchmarks applied to the fossil-fuel portion of a state's electricity generation fleet (Figure 3) and to an entire fleet, including renewables (Figure 4).

Figure 3: Emission Reductions Based on NRDC Benchmarks, Fossil Fleet Only [3]



[3] Figure 3 illustrates the approximate minimum percentage reduction of total simple carbon dioxide emissions from utility-scale electricity generation in 2012 required for each state to be able to achieve the emission rates proposed by the NRDC in each benchmark year from 2020 to 2030 and beyond. Emissions data for 2012 were collected by state and year from the Continuous Emissions Monitoring Systems available in the EPA Clean Air Markets Program Database. The effective NRDC emission rates benchmarks for each state were calculated using the formula specified in Appendix A and 2005 net electricity generation data from fossil fuel units (coal, natural gas, and petroleum) per the Power Plant Operations Report available in the U.S. Energy Information Administration, Form EIA-923. Alaska and Hawaii were excluded from this analysis because comparable 2012 emissions data were not available for these states from the EPA Clean Air Markets Program Database.

Figure 4: Emission Reduction Requirements by State Based on NRDC $C0_2$ Emission Benchmarks, Total Fleet



"While natural gas is currently relatively inexpensive, locking ourselves into a single-fuel economy poses significant risks in the future as natural gas prices increase, as they would be expected to do with a substantial increase in demand from the utility sector."

States should not be placed in a position of choosing between energy efficiency and renewable energy versus a fossil fueled fleet that becomes dependent on yet another single source of fuel, natural gas. In either of the rate-based approaches depicted in Figures 3 and 4, Kentucky is faced with significant challenges in meeting the 2020, 2025 and 2030 target fossil fleet rates.

Such an approach is not realistic because it is not feasible or appropriate to assume that coal facilities would be in a position to cost effectively add on control equipment to reduce adequately the pounds of CO_2 generated per MW-h produced or have the means to sequester those emissions. Furthermore, a rate-based standard that uses natural gas—specifically combined cycle systems—as a surrogate for add-on CO_2 control technologies is one that unfairly advocates for a single fuel economy. This approach would force coal plant conversions to natural gas in the absence of available proven technology.

As shown, a rate-based standard can either be a force for electric generating unit efficiency upgrades or a push to an alternative fuel. At this time, the market favors the fuel of choice being natural gas. While natural gas is currently relatively inexpensive, locking ourselves into a single-fuel economy poses significant risks in the future as natural gas prices increase, as they would be expected to do with a substantial increase in demand from the utility sector.

These scenarios not only have significant implications for the nation's manufacturing economy, but they also place a burden on many states that continue to struggle with a slow economic recovery. As the nation is only slowly emerging from a severe economic recession, such a regulatory scheme would not be in the best interests of the nation and does not offer states the amount of flexibility necessary to successfully implement Section 111(d).

KENTUCKY'S PROPOSED FRAMEWORK

Kentucky proposes an equitable and cost-effective approach that provides the needed flexibility to comply with a Section 111(d) plan. In the absence of control technology for existing EGUs, compliance options include offsets, demand-side energy efficiency, renewables and other low-carbon fuels, and supply-side efficiency improvements. Our proposed framework will diversify Kentucky's electricity generating portfolio, reduce emissions, and benefit the economy.

Kentucky has identified the following objectives for the framework outlined below:

- Utilize mass-emission reductions from the fossil fueled electricity generating sector as the primary mechanism for addressing greenhouse gases in Kentucky.
- Ensure that the fossil fueled electricity generating sector has the time and resources necessary to transition to a cleaner fleet when necessary and appropriate.
- Provide that the fossil fueled electricity generating sector has the flexibility to choose the least-cost method of achieving reductions.
- Encourage diversity for Kentucky's electricity generation fleet.

A mass-emission reduction standard provides state flexibility under Section 111(d) guidelines that encourage CO_2 reduction from multiple pathways, achieves sustained greenhouse gas reductions, and encourages economic growth until the commercial availability of CCS technology has been demonstrated as feasible and cost effective on a large scale for the power sector. Such an approach also allows a state to take advantage of emission reductions achieved through coal-plant retirements and fuel-switching based on other existing Clean Air Act regulations.

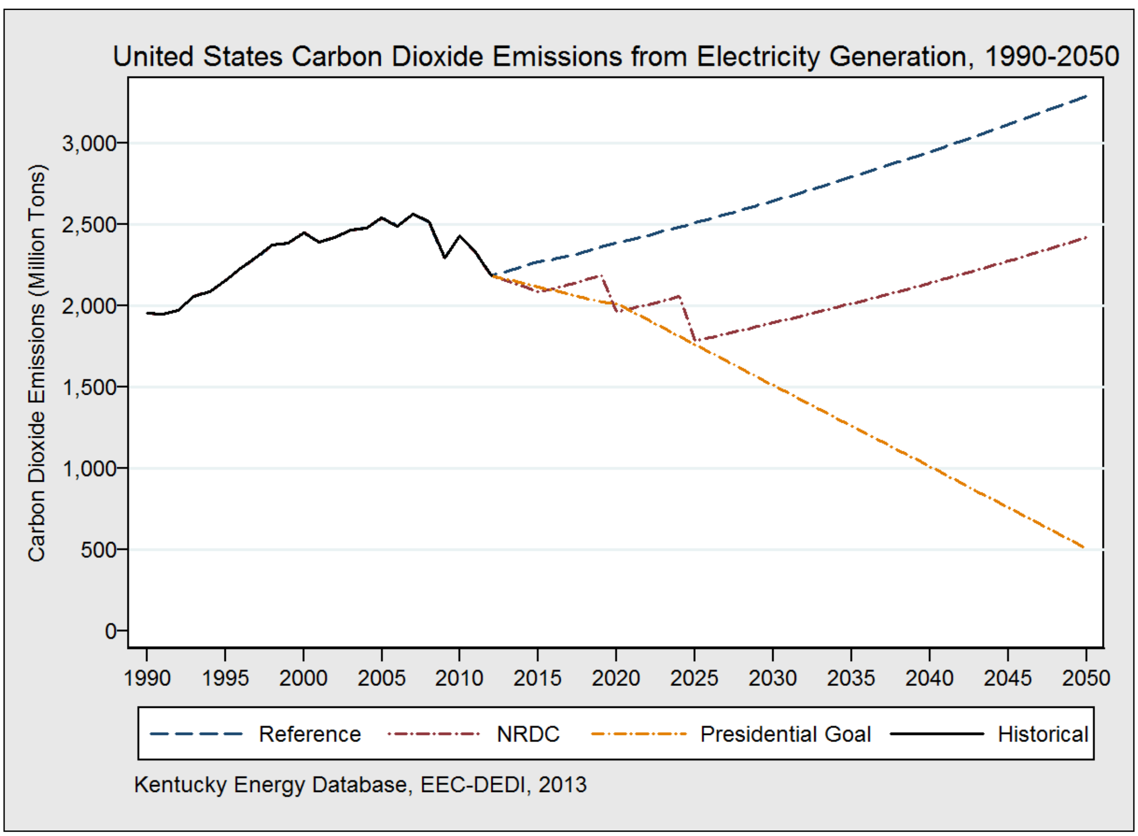
In a typical scenario, the EPA would set a NAAQS for greenhouse gases, and states would have at least three years to develop state implementation plans to demonstrate how they will attain and meet the NAAQS. These plans give states the flexibility to devise regulations to control sources within their own state. However, greenhouse gases, which are emitted from multiple sectors, including the transportation and industrial sectors, are unlike other pollutants where NAAQS have been established. Just as a NAAQS does not logically apply to regulating greenhouse gas emissions, a traditional rate-based regulatory framework has its limitations.

In the absence of a NAAQS, EPA is faced with calculating the amount of emission reductions required from the electricity generating sector to be protective of public health and the environment under 111(d), taking into account other emission reduction sources and contributors. To date the only levels of overall emission reductions stated by the President have been a 17 percent reduction from 2005 levels by 2020 with an 80 percent reduction by 2050. EPA would still be in a position under 111(d) to demonstrate that these mass-emission reductions stabilize or reduce CO_2 concentration in the atmosphere.

Given the difficulty of this task and as an alternative, EPA could allow states the flexibility to determine emission reductions that are appropriate given each state's own fossil fuel portfolio mix, existing life of affected electricity generating units, market conditions, and renewable energy potential along with any quantifiable energy efficiency gains. This approach would help mitigate the potential adverse economic and social impacts to states that have a strong manufacturing base and allow a path forward to develop a plan that can ensure diversity in energy sources, cleaner sources of energy, as well as economic stability.

Figure 5 illustrates that a mass-emission reduction standard is one that achieves sustainable reductions for the future, is not disproportionate among states, and can offer the tools for the development of state-specific programs considering state resources and economic conditions. Figure 5 juxtaposes the forecasted sum of state-level simple carbon dioxide emissions from electricity generation under the following three cases. The Reference case assumes that electricity generators in each state continue to emit CO_2 at 2012 emissions rates, with anticipated growth, as calculated from the EPA Clean Air Markets

Figure 5: U.S. $C0_2$ Emission Forecasts, 1990-2050



Program Database. The NRDC case assumes that fossil fuel generating stations in each state emit carbon dioxide at the maximum rate proposed by the NRDC benchmarks using a 2005 baseline, while holding constant the proportion of each state's generating portfolio derived from fossil fuels to 2050. The Presidential Goal case assumes that each state achieves a 17 percent reduction by 2020, and 80 percent by 2050, in simple carbon dioxide emissions from electricity generation from 2005 levels.

Kentucky's framework contains the following provisions:

1. Establish a statewide baseline CO_2 level using the CO_2 emission from fossil fueled electric generating units from 2005.
2. Establish the following baseline CO_2 reduction targets for 2020 (17 percent reduction), 2025 (28 percent reduction), and 2030 (38 percent reduction). Beyond 2020, state-specific data as well as energy portfolio trends would be used to set additional reductions beyond 2020 achievable through demand-side and supply-side efficiencies, renewable and other low-carbon energy potential, offsets, and any control technology gains. The 2050 target is the 80 percent reduction goal proposed by President Obama.
3. Obtain credit for CO_2 reductions that have occurred from the baseline established in item 1, thereby allowing states to comply with baseline reduction targets established in item 2.
4. Allow a suite of compliance options that would enable Kentucky to implement the least-cost method of meeting reduction targets. These compliance options would include, but not be limited to:
    - Demand-side energy efficiency
    - Supply-side conservation or efficiency programs
    - Transmission upgrades
    - Renewable and other low-carbon energy projects at the affected source or at the consumer level
    - Carbon Capture and Sequestration (CCS) technology
    - Fuel switching to lower emitting fuels
    - Quantifiable and verifiable offsets
    - Participation in regional or national market-based CO_2 credit-trading programs
5. Establish an enforcement and monitoring mechanism whereby the state would be responsible for review, verification of emission estimates and reductions, and approval of the compliance options above. In addition, the state would be responsible for tracking statewide trends and projects.

Compliance Options

Potential compliance options available under Kentucky's 111(d) framework are outlined using findings from the Kentucky Climate Action Plan Council's (KCAPC) final report. [4] The analyses used in developing the KCAPC report were conducted in partnership with the Center for Climate Strategies, and although some of the underlying assumptions have changed, the relative impact of various options' ability to reduce greenhouse gases and their relative cost are useful in understanding the benefits of a mass emission-based standard over a rate-based standard. Kentucky's Energy and Environment Cabinet is in

[4] Final report of the Kentucky Climate Action Plan Council, November 2011. http://energy.ky.gov/carbon/pages/default.aspx

the process of developing the Kentucky Electricity Portfolio Model that will enable the agency to better understand the impact of changes to the state's electricity portfolio. Whether changes are driven by environmental regulations, state or federal policies, or economic market conditions, the cabinet will soon be able to determine the impact of the changes on price, fuel consumption, and ultimately jobs.

Demand and Supply-Side Energy Efficiency

Energy efficiency remains an essential element to Kentucky's framework because it is a cost-effective tool for reducing greenhouse gas emissions. When paired with more costly compliance strategies, the savings from energy efficiency can mitigate the cost of supply-side diversification. A standard that does not include efficiency as a primary compliance tool increases the compliance burden, as demonstrated in Table 2. Kentucky has a number of active energy-efficiency initiatives and has received broad stakeholder support for demand-side energy efficiency through its Stimulating Energy Efficiency in Kentucky (SEE-KY) program. As a result of this initiative, Kentucky, through the cooperation of utility and other stakeholders, is committed to reducing electricity generation by 1 percent annually between 2015 and 2020.

"Kentucky has a number of active energy-efficiency initiatives and has received broad stakeholder support for demand-side energy efficiency through its Stimulating Energy Efficiency in Kentucky (SEE-KY) program."

Renewable Electricity and Fuel Switching

Kentucky can realistically and cost-effectively increase its renewable electricity generation to 15 percent by 2030. Assuming Kentucky achieves just a third of this goal (5 percent) by 2020 and relies on mostly out-of-state wind along with some in-state hydro, wind, solar, and landfill gas-generated electricity, the state can avoid 7.4 MMt CO_2e at a cost per ton of $11.

Kentucky is already experiencing retirements of coal units, with much of the lost capacity being replaced by new natural gas combined cycle units. This level of fuel switching is realistic, even without stringent rate-based emissions standards. The table also includes estimated reductions of 800 MW of traditional coal generation were to be replaced with supercritical coal generation with 90 percent carbon capture and storage.

Carbon Offsets

Analyses on carbon sequestration through reforestation indicate this would be an achievable and affordable emission-reduction strategy. Reforestation of 22,700 acres of previously mined land by 2020 would avoid 0.02 MMt CO_2e. An additional 142,000 acres of other (non-mined) land could be reforested in Kentucky by 2020 avoiding 0.55 MMt CO_2e by 2020. These reforestation estimates are conservative. We have initiated discussions with volunteer-driven organizations for reforesting 2 million acres over a 15 to 20 year time period, with an estimated 2 to 3 tons of carbon dioxide capture per acre.

Table 2 summarizes estimated emissions reductions and cost, based on analyses performed through the KCAP process, for each of these possible compliance options.

Table 2: Total Emissions Reductions Estimated Through Possible Compliance Options by 2020

Strategy	**MMt CO_2e Avoided**	**Cost/t CO_2e ($2009)**
Supply-Side Efficiency	1.6	$8.0
Demand-Side Efficiency	6.0	-$20
Switch to 5% Renewable Electricity	7.4	$11
Switch to 20% gas	8.7	$17
Replace 800 MW with supercritical with CCS	2.3	$33
Reforest Mine and Other Lands	1.6	$3.7
Total	27.6	$9.3

These strategies demonstrate that a more holistic and less costly approach could be implemented to reduce overall greenhouse gas emissions, and offer a more effective tool than a rate-based emissions standard to help Kentucky achieve the President's stated emission reduction goals. In fact, a strategy that omits the benefits of supply and demand-side efficiency and carbon offsets results in approximately 30 percent less CO_2e reduced. Kentucky is positioned to spend less money while reducing more greenhouse gases using a suite of compliance options that include efficiency and carbon offsets.

"Kentucky is positioned to spend less money while reducing more greenhouse gases using a suite of compliance options that include efficiency and carbon offsets."

Identified EPA Opportunities for State Flexibility

The framework outlined by Kentucky presents many opportunities for emissions reductions. The following discussion outlines areas of concern whereby EPA should provide flexibility under Section 111(d).

NSR/PSD Regulatory Issues

By establishing a flexible emission reduction framework, regulated entities are given an incentive to find the least-cost method to achieve compliance. Sources might invest in efficiency upgrades that would normally trigger PSD/NSR review.

Kentucky is recommending that EPA consider implementing a mechanism for sources that opt to invest in efficiency upgrades and are not precluded from doing so by NSR/PSD permitting requirements, if those efficiency improvements are consistent with meeting Section 111(d) guidelines and do not jeopardize violation of an existing National Ambient Air Quality Standard.

Regional or National Market Based CO_2 Programs

Kentucky's proposed framework sets a statewide mass-emission limit that could be the foundation for an allocation program. If it is determined that allocating allowances is the best path forward in Kentucky, state authorities will have within its discretion to define if allowances will be sold (auctioned) or offered freely to the affected sources. In this program, holding of the allowances and credits becomes the *de-facto* method of demonstrating compliance. In this policy scenario, sources that did not acquire sufficient auction allowances would be required to use the compliance options outlined to make up the difference between their auction allowances purchased and those allocated.

Once the allowances are allocated to the source either via auction or free allocation, trading between the sources would be at the discretion of state authorities. Kentucky does not see an obvious benefit of a state-only trading program but believes that a federal or regional program potentially could provide added incentive for reductions among the sector.

Kentucky's recommendation allows affected sources to participate in market-based programs. An EPA designed regional or national auction, banking, or trading program could help with state SIP development; however, Kentucky would encourage EPA to allow:

- Offsets or credits within state boundaries that are consistent with the President's Climate Action Plan and the GHG Reporting Rule;
- The ability to set a price floor on auction allowances;
- The ability to determine a price ceiling on offsets; and
- The ability of commonly owned affected sources to borrow credits among those under common ownership.

Verification and Quantification of Energy Efficiency

Kentucky's framework allows "credit" for energy efficiency programs. For approval of source compliance strategies as well as Section 111(d) SIP development, a more detailed approach on how to account for energy efficiency gains and how to translate them into CO_2 reductions must be developed. With no explicit guidance on how to accomplish this from EPA and no prior SIPs approved by EPA that include these measures, Kentucky would face significant hurdles in developing a strategy in the limited time between the final rule date of June 1, 2015, and the proposed June 30, 2016, SIP submittal date.

Any strategy included in a proposal translates into a more formalized program to document, track and translate energy efficiency gains. For many states, this type of knowledge is not within state air quality programs. To lessen this gap, Kentucky is requesting EPA to develop specific approved methodologies for quantification and verification of energy efficiency program results. Without such methodologies, states are burdened with developing methods that may not be consistent nationwide.

CONCLUSIONS

Without the flexibility afforded under the Clean Air Act Section 111(d) for a mass-emissions approach, Kentucky and other heavy manufacturing states will face serious economic impacts and job losses. We welcome the opportunity to engage the EPA with a framework that ensures Kentucky's economy and energy portfolios are not crippled by an unachievable, rigid performance standard and presents opportunities for a level playing field under Section 111(d).

The market can be a powerful tool and provides needed flexibility for a sector that is faced with a lack of control options; however, market-based approaches can be labor intensive to operate and monitor in terms of the state's capacity to implement such a program. There is also great variability in market programs due to changing market conditions (technology advancement, price of fuels, renewable subsidies, etc.) which may yield unexpected results. These results ultimately may not be in line with state targets or goals.

"It is imperative that EPA allow ample time and work in collaboration with states to design programs that are 111(d) compliant but provide states the needed flexibility to ensure economic stability."

For Kentucky, this lends itself to a framework that places a priority on the flexibility of market systems such as declining caps, auctions, banking, trading, and offsets coupled with the enforceability of a mass-based emission limit both statewide and at the source. In the absence of control technology for existing EGUs, compliance options include offsets, energy efficiency, renewables, and supply-side efficiency improvements. It is our expectation that this framework will yield results of increased diversity in Kentucky's electricity generating portfolio, a cleaner environment, and a thriving economy.

However, in order to successfully implement the framework outlined, Kentucky also identifies that significant state resources must be utilized and that EPA guidance and flexibility on key issues would allow for a SIP development that is not overly burdensome on state agencies. It is imperative that EPA allow ample time and work in collaboration with states to design programs that are 111(d) compliant but provide states the needed flexibility to ensure economic stability.

APPENDIX A

Kentucky's Current CO_2 Performance Status

Given that target emission rates are developed by including a state's baseline generation mix, the first task is to establish Kentucky's baseline fossil fuel generation. Table 3 represents what is currently operating (Year 2012) and does not include any speculation as to closures or fuel switching.

Table 3: Kentucky Fossil Fuel Baseline Generation, 2012

Fuel Type	Generation MW-h	% MW-h
Coal	92,793,081	97.15%
Diesel Oil	12,827	0.01%
Pipeline Natural Gas	2,713,143	2.84%
Total	**95,519,051**	**100.00%**

The second task is to calculate Kentucky's fossil fleet average target emission rates using the NRDC proposal as a guideline. Table 4 shows Kentucky's NRDC emission target rates for 2020 and beyond 2025. Table 5 shows the weighted average for each fuel type in 2012. Table 5 also illustrates the best performing units in Kentucky by fuel type. For coal-based utilities, the best performing plant achieves 1,743 pounds of CO_2 per MW-h. For natural gas, the best performer achieves 1,094 pounds of CO_2 per MW-h.

Table 4: Kentucky Fossil Fleet Target Emission Rate under NRDC Proposal

NRDC Kentucky 2015-2019 Target Emission Rate* (lbs CO_2/MW-h)	NRDC Kentucky 2020-2024 Target Emission Rate*(lbs CO_2/MW-h)	NRDC Kentucky 2025 & Beyond Target Emission Rate*(lbs CO_2/MW-h)
1,777	1,485	1,194
* Using a 2012 current fleet split of 97% Coal and 3% NG/Oil by MW-h generated		

Table 5: Kentucky Current CO_2 Emission Rate Profile

Fuel Type	Min (lbs CO_2/MW-h)	Max (lbs CO_2/MW-h)	2012 Actual Fleet Averages* (lbs CO_2/MW-h)	2020 NRDC Target Emission Rate (lbs CO_2/MW-h)	2025 NRDC Target Emission Rate (lbs CO_2/MW-h)
Coal	1,743	2,472	1,969	1,500	1,200
Natural Gas	1,094	1,836	1,316	1,000	1,000
Oil	1,595	1,661	1,641	1,000	1,000
Fleet Average			1,951	1,485	1,194
			*Weighted average based on MW-h generated		

Proposed Kentucky Fossil Fleet Changes

Given what is known about future power plant retirements and speculative conversion, Table 6 updates Table 3 and shows projected fleet generation mix by fuel type. Table 7 builds upon the fossil fleet generation changes in Table 6 and shows the projected CO_2 emission rates by fuel type as compared to the NRDC targets. Table 4 calculated a baseline Kentucky fleet average of 1,950 pounds of CO_2 per MW-h. The fleet average in Table 7 of 1,800 pounds of CO_2 per MW-h shows improvements; however, when compared to NRDC targets, a significant gap still remains.

Table 6: Projected Fossil Fleet Generation Changes

Fuel Type	% of MW-h
Coal	83.02%
Diesel Oil	0.01%
Pipeline Natural Gas	16.96%
Grand Total	**100.00%**

Table 7: Kentucky Projected Fleet CO_2 Profile compared to NRDC Proposal

Fuel Type	Projected Averages (lbs CO_2/MW-h)	2020 NRDC Target Emission Rate (lbs CO_2/MW-h)	2025 NRDC Target Emission Rate (lbs CO_2/MW-h)
Coal	1,961	1,500	1,200
Diesel Oil	1,641	1,000	1,000
Pipeline Natural Gas	1,011	1,000	1,000
Fleet Average	1,800	1,485	1,194

APPENDIX B

Kentucky's Current and Future Estimates of Fossil Fleet CO_2 Mass Emission Reductions

	2005	2012	Scenario #1* 2020	Scenario #2* 2025	Scenario #3** 2030
Million Tons of CO_2 Emission data from CAMD Acid Rain Database	100.2	93.2	80.30	72.94	62.11
% Reduction from 2005		-6.99%	-19.83%	-27.23%	-38.00

*Speculative changes in electricity generating portfolio based on internal discussions with stakeholders
** Kentucky 111(d) framework target benchmark based on President's goal

Analyses

This paper utilizes NRDC's benchmarks to analyze a rate-based approach for analysis purposes. Under the rate-based approach analyzed, there is a statewide target fossil fleet average emission rate with specific benchmarks for coal and oil/gas units. States like Kentucky with more carbon-intensive fleets would have higher target emission rates but a greater differential between starting emission rates and their targets.

The NRDC benchmarks for state fossil fuel generation fleets established for 2015 to be met by 2020 include 1,800 pounds of CO_2 per MW-h for coal units and 1,035 pounds of CO_2 per MW-h for natural gas and oil units. By 2025, the benchmarks are 1,500 pounds of CO_2 per MW-h for coal units and 1,000 pounds of CO_2 per MW-h for natural gas and oil units. By 2030, fleet coal units must achieve 1,200 pounds of CO_2 per MW-h and the natural gas benchmarks remain the same. The formula for calculating the state target emission rate is given below:

1. For 2015–2019, state/regional rate = [1,800 lbs/MW-h] × [baseline coal generation share of state region] + [1,035 lbs/MW-h] × [baseline oil/gas generation share of state/region]
2. For 2020–2024, state/regional rate = [1,500 lbs/MW-h] × [baseline coal generation share of state region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
3. For 2025 and thereafter, state/regional rate = [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]

For 2020, state/regional target emission rate:

= [1,500 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= (1500 lbs/MW-h * 0.97) + (1000 lbs/MW-h *0.03)
= 1455 lbs/MW-h + 30 lbs/MW-h
= 1,485 lbs/MW-h

For 2025 and thereafter, state/regional rate target emission rate:

= [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= (1200 lbs/MW-h * 0.97) + (1000 lbs/MW-h *0.03)
= 1164 lbs/MW-h + 30 lbs/MW-h
= 1,194 lbs/MW-h

Table 5 Calculations

The weighted mean of a set of data $\{x_1, x_2, \ldots, x_n\}$ with non-negative weights $\{w_1, w_2, \ldots, w_n\}$, is represented by the formula below

$$\bar{x} = \frac{\sum_{i=1}^{n} w_i x_i}{\sum_{i=1}^{n} w_i},$$

which translates to the following formula:

$$\bar{x} = \frac{w_1 x_1 + w_2 x_2 + \cdots + w_n x_n}{w_1 + w_2 + \cdots + w_n}.$$

For Table 5 calculations, the formula uses the MW-h for each fuel as the weight (W) and the individual fuel's lbs CO_2/MW-H is the value (X) in the formula. This is illustrated with the 2012 data shown on Table 8 on Page 21. For Table 7, the process is repeated using revised electricity generating fleet data to reflect shutdowns and conversions to natural gas.

Table 8: 2012 MW-h and CO_2 Emissions by Fuel Type

Column Identifier	A	B	C	D=(A+B+C)	E	F	G	H = (E+F+G)
	MW-h from Coal	MW-h from Oil	MW-h from NG	Total MW-h	lbs of CO_2 from Coal	lbs of CO_2 from Oil	lbs of CO_2 from NG	Total lbs of CO_2
	92,793,081	12,827	2,713,143	95,519,051	182,744,159,958	21,043,885	3,570,824,993	186,336,028,836

Row Identifier	Description	Formula	Result from 2012 Data (lbs of CO_2/MW-h)
I	2012 Fleet CO_2 lbs/MW-h from Coal	=E/A	=1,969
J	2012 Fleet CO_2 lbs/MW-h from Oil	=F/B	=1,641
K	2012 Fleet CO2 lbs/MW-h from NG	=G/C	=1,316
	2012 Weighted Total Fleet lbs CO2/MW-h	$=\frac{(A*I)+(B*J)+(C*K)}{D}$ =(A/D)*I + (B/D)*J + (C/D)*K =(coal lbs/MW-h × % of electricity generated that is coal) + (oil lbs/MW-h × % of electricity generated that is oil) + (NG lbs/MW-h × % of electricity generated that is NG) **= (0.9715*1969) + (0.0001 *1641) + (0.0284*1316)**	=1,951

APPENDIX C

Current Large-Scale CCS Projects

Project Name	Leader	Feedstock	Size MW	Capture Process	CO_2 Fate	Status	Location
USA							
Kemper County	Southern	Coal	582	Pre	EOR	Under Construction	Mississippi
TCEP	Summit Power	Coal	400	Pre	EOR	Planning	Texas
WA Parish	NRG Energy	Coal	240	Post	EOR	Planning	Texas
HECA	SCS	Petcoke	400	Pre	EOR	Planning	California
FutureGen	FutureGen Alliance	Coal	200	Oxy	Saline	Planning	Illinois
Canada							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Boundary Dam	SaskPower	Coal	110	Post	EOR	Under Construction	Saskatchewan
Bow City	BCPL	Coal	1000	Post	EOR	Planning	Alberta

European Union							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Ferrybridge	SSE	Coal	500	Post	Depleted Oil	Construction of Pilot	UK
ROAD	E.ON	Coal	250	Post	Saline	Planning	Netherlands
Compostilla	ENDESA	Coal	323	Oxy	Saline	Planning	Spain
Getica	Turceni Energy	Coal	330	Post	Saline	Planning	Romania
Peterhead	Shell and SSE	Gas	385	Post	Depleted Gas	Planning	UK
Don Valley Power Project	2Co Energy	Coal	920	Pre	EOR	Planning	UK
Teesside Low Carbon	Progressive	Coal	400	Pre	Depleted Oil	Planning	UK
Killingholme	C.GEN	Coal	430	Pre	Saline	Planning	UK
White Rose	Capture Power	Coal	426	Oxy	Saline	Planning	UK
Porto Tolle	ENEL	Coal	250	Post	Saline	Planning	Italy
Captain	Summit Power	Coal	400	Post	Depleted Oil	Planning	UK
Magnum	Nuon	Various	1200	Pre	EOR/ EGR	Planning	Netherlands

Norway							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Mongstad	Statoil	Gas	350	Post	Saline	Operational May 2012	Norway
Longyearbyen	Unis CO2	Coal	N/A	N/A	Saline	Planning	Norway
Rest of the World							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Daqing	Alstom & Datang	Coal	350	Oxy	EOR	Planning	China
HPAD	Masdar	Gas	400	Pre	EOR	Planning	UAE
GreenGen	GreenGen	Coal	250/400	Pre	Saline	Planning	China

Source: http://sequestration.mit.edu/tools/projects/index_capture.html
Oxy = Oxyfuel Combustion Capture; Pre = Pre Combustion Capture; Post = Post Combustion Capture ; EOR = Enhanced Oil Recovery; EGR = Enhanced Gas Recovery; Saline = Saline Formation; Depleted Gas = Depleted Gas Reservoir; Depleted Oil = Depleted Oil Reservoir; TBD = To Be Decided