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April 22, 2014

The Honorable Gina McCarthy, Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Administrator McCarthy:

On behalf of the Commonwealth of Kentucky, I am forwarding comments from the Kentucky Energy and Environment Cabinet on EPA's proposed regulations for Greenhouse Gas Emissions from new stationary sources. In our previous conversations regarding the regulatory mechanisms to address CO_2 emissions from power plants, I expressed concerns, both legal and technical, with the proposed regulations issued under Section 111(b) of the Clean Air Act. More importantly, the potential devastating economic impacts that a flawed regulatory structure may have on a producer state, like Kentucky, are detailed in the whitepaper, *Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act*. Through the submittal letter dated October 22, 2013, I also informed you that we would communicate our specific concerns of the problematic elements of EPA's proposed rules for new power plants.

Although the revised proposed *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* addresses several of the issues raised in our previous comments submitted on June 25, 2012, we remain convinced that this iteration of rulemaking continues to jeopardize our state's economy and future prosperity. By establishing an unreasonable and unattainable emissions limit for coal combustion at 1,100 lbsCO_2/MWh, the proposed standards effectively eliminate the construction of any new coal-fired power plants. Recent winter weather events demonstrate that there will always be a need and demand for reliable, cost-effective sources of electricity, such as coal. Therefore, the narrowing of energy options by this proposed rule is inconsistent with the President's all-of-the-above energy strategy and is detrimental to national security and to the economies of Kentucky and the nation.

In response to EPA's request for comment on the range of 1,000-1,200 lbsCO_2/MWh, the Cabinet requests that EPA consider 1,700 lbsCO_2 /MWh as the limit for coal-fired boilers. While not in the specific range requested for comment, this emission limit would accomplish nearly 20 percent CO_2

emission reductions compared to the national average of 2,100 $lbsCO_2/MWh$ for the current U.S. coal-fired fleet. This standard is being achieved by only the cleanest and most recently commissioned coal-fired units in the nation, setting an aggressive target for new generation and requiring technology advancement through the New Source Review program.

Kentucky remains committed to reducing greenhouse gas emissions, but we must protect the welfare of our citizens and the economy of our state. We are an energy intensive state due to our significant manufacturing base, which is reliant on stable and low electricity prices. We provide many of the goods and services that other states consume. This proposed rule effectively eliminates Kentucky's future ability to rely on our most abundant natural resource—coal. The substitution of natural gas for coal is not a long-term solution for climate change and potentially results in disastrous short-term consequences of decreasing state gross domestic product, rising unemployment, dramatically fluctuating prices that negatively impact consumers, increasing security risks and decreasing the standard of living for many Kentuckians.

In closing, Kentucky appreciates the opportunity to provide comments on the proposed rulemaking. We share the goals of clean air, water, and land and want to ensure that the standards proposed are legally sound, non-biased, achievable, and consistent with Congressional intent. We certainly share your goals to reduce GHG emissions; however, we do not believe that 111(b) as currently structured, legally and consistently accomplishes these goals. We hope that you find these comments beneficial and look forward to your responses on the significant issues raised in our comments. If you have questions or need clarification regarding our comments, please contact Ms. Karen Wilson, Chief of Staff, or Mr. John Lyons, Assistant Secretary, at (502) 564-3350.

Sincerely yours,

L K Peters

Leonard K. Peters
Secretary

Docket ID No. EPA-HQ-OAR-2013-0495

Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

Executive Summary

In a *Federal Register* published January 8, 2014, the Environmental Protection Agency (EPA) re-issued the proposed *Standards of Performance for Greenhouse Gas Emissions from New stationary Sources: Electric Utility Generating Units (EGUs)*. The proposed standards are mandated by the President's *Climate Action Plan and Executive Order,* released in June 2013.

After extensive review of the proposed rulemaking, Kentucky has several significant concerns, particularly the emission limitation set for coal-fired EGUs. By setting an unreasonable standard for coal combustion technology at 1,100 lbsCO_2/MWh, achievable only through partial carbon capture and storage (CCS) that has not been demonstrated at the scale needed for base-load generation, EPA is effectively setting energy policy through an environmental protection regulation. This policy decision will neither advance the research and development of CCS as claimed by EPA, nor will it maintain the necessary diversity in states' energy profiles that will keep electricity prices reasonable for a vibrant national economy.

EPA's repeated logic that no coal-fired EGUs are expected to be built in proposing this unattainable standard is counterintuitive to promoting CCS or even advanced coal combustion technologies, such as ultra-supercritical pulverized coal (USCPC). In conjunction with the current market forces of competitive natural gas prices, this standard ensures that no coal technologies, with or without CCS, will be pursued. Thus, this rulemaking creates an inherent bias, which will drive fuel switching to natural gas and put the country at a greater risk than a balanced energy profile will provide.

EPA inexplicably assigns no significant carbon dioxide (CO_2) emission reductions resulting from the rule making. Without any clearly defined environmental benefits, the proposal is unnecessary. Regulations promulgated under Section 111(b) of the *Clean Air Act* (CAA) should not serve merely as a vehicle to subsequently limit emissions from existing sources.

EPA has also erred in its economic analysis, admitting that economy-wide modeling results are not available. This falls far short of a thorough economic analysis, and the unknown effects are potentially significant on gross domestic product (GDP) and increased unemployment in predominantly manufacturing states. The Cabinet's analysis demonstrates that the resultant impact of the rule is a significant loss of manufacturing jobs.

The nation, as a whole, would be better served by EPA recognizing the necessity for fuel diversity in the generation of electricity. Therefore, the Cabinet requests that EPA consider setting the emission standard for the performance of new EGUs at 1,700 lbsCO_2/MWh[1] limit for

[1] Based on the average emission rates of the top 5 coal-fired units in 2013, EPA's *Clean Air Markets Division*

the coal-fired boilers, regardless of the combustion technology employed. While not in the specific range for which EPA is requesting comment, this limit would accomplish significant CO_2 emission reductions (19 percent) as compared to the annual average of 2,100 lbsCO_2/MWh for the current U.S. coal-fired EGU fleet.[2]

[2] Based on the national average emission rates of the coal-fired units in 2013, EPA's *Clean Air Markets Division*

Comments from the Kentucky Energy and Environment Cabinet

On January 8, 2014, U.S. EPA proposed a new rule regulating the emissions of CO_2 from fossil fuel-fired power plants. By establishing unachievable emission standards for coal-fired power plants, the proposed standards eliminate the construction authority of new coal-fired power plants, effectively regulating them out of the nation's energy generation fleet. In doing so, the EPA is imposing energy policy by executive decree and infringing on the authority of Congress to establish national energy policy for the United States.

The Cabinet requests the Administrator withdraw the proposed rule and reconsider the issues addressed in the following comments.

I. Necessity

"The EPA projects that this proposed rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022." **79 FR 1434. See also 79 FR 1496.**

In EPA's own estimation, this proposed rule will not result in meaningful reductions of CO_2 emissions. Since the proposed rule will not result in meaningful reductions in carbon dioxide emissions, the proposed rule is not beneficial or necessary. It is arbitrary for the EPA to use the CAA to issue a rule that the Administrator has determined will have a "negligible" impact on air quality.

Without clearly defined environmental benefits, the Cabinet finds this rulemaking unnecessary.

II. Purpose

"The proposed rule will also serve as a necessary predicate for the regulation of existing sources within this source category under CAA section 111(d)." **79 FR 1496.**[3]

Regulations promulgated pursuant to Section 111(b) of the CAA should not serve merely as a vehicle to subsequently limit emissions from existing sources. Instead, standards of performance shall be established based upon the best system of emission reduction (BSER) adequately demonstrated, taking into account the cost of achieving such reduction as required by Section 111(a) of the CAA and apply to new, modified, and reconstructed sources.

The EPA cannot arbitrarily issue unnecessary and unbeneficial standards under Section 111(b) with the intent of triggering the regulatory authority for existing sources under Section 111(d). As EPA's purpose in promulgating this proposed rule is to serve as a predicate to regulate existing sources under Section 111(d) of the CAA, the Cabinet requests the Administrator withdraw the proposed rule and reconsider the proposal.

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[3] The *Regulatory Impact Analysis* (RIA) at 1-4, paragraph 2 states: "The proposed rule is also a prerequisite for the regulation of existing sources with this source category under CAA Section 111(d)."

III. Emission Standards are Unreasonable

"This action proposes a standard of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage (CCS) as the BSER. The proposed emission limit for those sources is 1,100 lb CO_2/MWh...This action also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lb CO_2/MWh for larger units and 1,100 lb CO_2/MWh for smaller units. At this time, the EPA is not proposing standards of performance for modified or reconstructed sources." **79 FR 1433.**

The proposal establishes separate standards for different fuel types that are arbitrary in application. The standard set for natural gas is currently achievable in practice with proven technology that is widely available to the industry. However, the standard set for coal-fired units is based on a capture and control technology that is unproven and has never been achieved in practice by an existing commercial-scale coal-fired power plant in the United States.[4]

In Kentucky, the best performing coal-fired unit is a circulating fluidized bed (CFB) EGU with an emission rate approximately 60 percent above the standard proposed by EPA. In contrast, the best performing natural gas unit operates in compliance with the standard proposed by EPA.[5] By establishing a standard that can be easily met by existing natural gas units while setting an unachievable standard for new coal units, this proposed rule is arbitrary and will force industry-wide fuel-switching from coal to gas. (Please refer to *Section V. Fuel Switching.*)

In response to EPA's request for comment on the range of 1,000-1,200 lbsCO_2/MWh[6], the Cabinet requests that EPA consider 1,700 lbsCO_2/MWh as the limit for coal-fired boilers. While not in the specific range requested for comment, this emission limit would accomplish CO_2 emission reductions greater than 19 percent as compared to the national average of 2,100 lbs for the current U.S. coal-fired fleet. Additionally, this standard is being achieved by only the cleanest and most recently commissioned coal-fired units in the nation, setting an aggressive target for new generation and requiring technology advancement through the New Source Review program. (Please refer to *Section VIII.B. Best Available Control Technology (BACT).*)

Furthermore, if EPA requires CCS, any emission standards associated with CCS technologies should address the parasitic load, along with the source-specific parasitic loads at each facility. In regard to parasitic loads, EPA states:

> "In general, less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output and about 2.5 percent of non-CCS combined cycle station power output is used internally by parasitic energy

[4] The test for achievability requires that the standard be achievable by the industry as a whole. *National Lime Association v. EPA*, 627 F.2d 416, 433 (1980).
[5] Colorado Bend Energy Center 56350-CT2A
[6] 79 FR 1470.

> demands, but the amount of these parasitic loads vary from source to source." **79 FR 1477.**

Currently, no fossil fuel-fired EGU is operating a CCS system at commercial scale, and based on available data, the Cabinet predicts that the parasitic load of CCS will be far greater than 7.5 percent as referenced above. For example, with a 30 percent parasitic load, which is near current expectations of CCS, an EGU designed to provide 1,000 MW would in actuality require 1,300 MW and therefore would emit 30 percent more CO_2. Thus, to achieve a 1,100 lbsCO_2/MWh limit on the 1,000 MW design it would require CCS capture efficiency of 60 percent for equivalent CO_2 reductions. This is a flawed engineering approach, especially when considering ancillary environmental impacts of requiring that 30 percent more coal would have to be mined to meet the desired overall reductions of CO_2 emissions.

In addition, given the predicted high parasitic load of a CCS, it is conceivable that a super-critical pulverized coal (SCPC) EGU without CCS would outperform a conventional unit equipped with CCS; however, neither design will be able to meet the emission limitations established in this regulation.

IV. Redefines and Mandates the Basic Fundamental Design of EGUs

"Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance." **79 FR 1444.**

The plain language of Section 111(b)(5) of the CAA states:

> "Except as otherwise authorized under Subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."

By requiring unreasonable and unachievable emission standards, the proposed regulation redefines and mandates the basic fundamental design of EGUs. Natural gas combined cycle (NGCC) is a combustion technology to generate electricity and is not a control system designed to reduce emissions. Thus, the proposed regulation sets a performance standard that requires the use of a certain type of fuel (natural gas) and a particular type of operation (NGCC) to meet the standard, which is in violation of Section 111(b)(5) of the CAA.

V. Fuel Switching

The practical impact of the inequitable emission standards in the proposed regulation forces fuel switching, which is in direct conflict with Congressional intent.[7] Congressional intent has been to encourage the use of local fuels, expand the energy resources that could be burned in

[7] *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 918 (1990); see also 136 Cong. Rec. S-16895-01 (1990).

compliance with emission limits, and to make technology and fuel choices less restrictive. In fact, the Congressional intent to utilize coal as a fuel source is clearly apparent in Section 111(a)(8) of the CAA.

Pursuant to Section 111(b) of the CAA, EPA must set an achievable standard for fossil fuel units that: is consistent with Congressional intent; encourages the use of local fuels; expands energy resources that could be burned in compliance with emission limits; and makes technology and fuel choices less restrictive.

VI. Control Technologies not "Adequately Demonstrated"

The commercial-scale demonstration projects used by EPA in the proposal are either not yet operating or are not implementing CCS. For example, Duke Power's Edwardsport plant, a 618 MW coal integrated gasification combined cycle (IGCC) unit located in Knox County, Indiana, began commercial operation in June 2013. Although capable, Edwardsport is not currently implementing CCS. **79 FR 1468.**

In addition, the Southern Company's Kemper County Energy Facility, a 582 MW lignite IGCC unit located in Kemper County, Mississippi, is not currently operating. **79 FR 1468.** Thus, EPA cannot determine whether Kemper is capable of achieving the emission standard as proposed.

Furthermore, EPA suggests that the Texas Clean Energy Project (TCEP), an IGCC plant (400 MW), is able to meet the proposed emission limitation. TCEP proposes to produce urea for the U.S. fertilizer market and capture 90 percent of its CO_2 – approximately 2.5 million tons per year – for Enhanced Oil Recovery (EOR). Even with these revenue streams, the project has not started construction as of October 2013.[8] At the end of 2013, Texas utility CPS Energy terminated a 25-year agreement to buy power from the Texas Clean Energy Project, creating further uncertainty to the project's economic viability.[9]

Also, EPA's analyses of CCS costs are based on demonstration projects that receive Department of Energy (DOE) financial assistance: "DOE [...] has committed $2.2 billion for 5 projects to date." **79 FR 1479.** Those projects must not be used as demonstration projects because such funds are limited and will not be available indefinitely. That financial assistance was available due to legislation that was passed to stimulate the economy during a recession by increasing spending for a specific time period. Thus, CCS cost estimates that factor in the availability of, or include, government subsidies misrepresent the true cost of implementing CCS technology.

The proposed regulation does not provide scientific evidence that long-term storage of CO_2 has been adequately demonstrated. Further, the proposed rule ignores Section 111(a)(1) of the CAA that requires EPA consider the "environmental impact" of long-term storage of CO_2. Considering that the proposed rule selects CCS as the BSER for coal-fired EGUs, EPA must consider the impacts of storing CO_2.

[8] http://sequestration.mit.edu/tools/projects/tcep.html
[9] http://dailycaller.com/2014/01/13/epa-agenda-suffers-setback-as-clean-coal-plant-project-is-derailed/

The standard established by the rule is unreasonable as it relies upon a technology that has neither been adequately demonstrated nor is commercially viable at this time for full-scale applications. **See 79 FR 1471.**

VII. Failure to Appropriately Determine BSER

"The CAA and subsequent court decisions (detailed later in this notice) identify the factors for the EPA to consider in a BSER determination. For this rulemaking, the following factors are key: feasibility, costs, size of emission reductions and technology." **79 FR 1434.**

After reviewing the rationale for each of the four factors, the Cabinet has determined that EPA failed to demonstrate and justify its selection of BSER for new coal-fired EGUs and IGCC units. Each factor is discussed as follows:

A. Technical Feasibility

"Feasibility: The EPA considers whether the system of emission reduction is technically feasible." 79 FR 1434.

i. Legal arguments

To justify the determination that CCS is technically feasible, EPA impermissibly relies upon the standard for "achievability" set forth by the D.C. Circuit Court's decision in *Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973).* **79 FR 1463.** However, the Court stated that, "If actual tests are not relied upon, but instead a prediction is made, its validity as applied to this case rests on the reliability of [the] prediction and the nature of [the] assumptions." *Id.* at 392. Considering that the CCS requirement is not "actual" but rather "prediction", the reliability of the prediction is at issue. It is important to note that the case was ultimately remanded with the Court stating that "the cause of a clean environment is best served by reasoned decision-making." *Id.* at 401.

While explaining the requirement of a control technology currently not in operation and not adequately demonstrated, EPA quotes from the decision: "The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry".[10] The projections and assumptions EPA relied upon are not reasonable and do not demonstrate that emission standards as proposed are achievable in practice. (Please refer to *Section III. Emission Standards are Unreasonable and Section VI. Control Technologies are not "Adequately Demonstrated".*)

[10] **79 FR 1463.**

In a further attempt to establish an achievability standard to support that CCS is "adequately demonstrated," EPA points to another D.C. Circuit Court case that fails to support the determination of CCS as BSER:

> "It should be noted that in another of the early cases, Essex Chemical Corp. v. Ruckelshaus, 486 F.2d 427 (D.C. Cir. 1973), the D.C. Circuit upheld a standard of performance as ''achievable'' on the basis of test data showing that the tested plant emitted less than or at the standard on three occasions and emitted above the standard on 16 occasions, and that, on average, it emitted 15 percent above the standard on a total of 19 occasions.[fn.]141 The fact that the plant had achieved the standard on at least a few occasions, even though the plant had not done so on the great majority of occasions, 'adequately demonstrated' that the standard was 'achievable.'" **79 FR 1463.**

Currently, there are no control technologies employed that allow any new commercial-scale coal-fired boilers and IGCC units to achieve the proposed standards. (Please refer to *Section VI. Control Technologies are not "Adequately Demonstrated".*) Unlike the situation described above, EPA fails to justify its determination and proposed limitations with any real test data that indicate whether a source is capable of achieving compliance.

ii. Science Advisory Board Review

EPA's Science Advisory Board (SAB) work group recommended that the SAB review the proposed rule in a November 12, 2013, memo.[11] In response, Peter Tsirigotis, Director of Sector Policies at EPA's Office of Air Quality Planning and Standards, delivered a presentation on December 4, 2013, to SAB that included the assertion, "EPA is not setting any new requirements related to sequestration and thus has not done a new analysis related to such requirements." EPA did not want the SAB to conduct an independent review of the scientific and technical basis of the proposed rule.

Contrary to EPA's assertion, the proposed rule effectively mandates CCS. EPA has a duty to comply with *The Environmental Research, Development and Demonstration Authorization Act* (ERDDAA), 42 U.S.C.A. 4365(c)(1), which requires that the EPA, "[...] shall make available to the Board such proposed criteria document, standard, limitation, or regulation, together with relevant scientific and technical information in the possession of the Environmental Protection Agency on which the proposed action is based." EPA's position that the proposed rule is not "setting any new requirements related to sequestration" and, therefore, the EPA is not required to provide relevant scientific and technical information underlying the sequestration component of the proposed rule is legally flawed.

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[11] Mihelcic, James R., *Preparations for Chartered Science Advisory Board (SAB) December 4-5, 2013, Discussions of EPA Planned Agency Actions and their Supporting Science in the Spring 2013 Regulatory Agenda* (November 12, 2013).

The issue is not whether the proposed rule sets any new requirements related to sequestration. The issue is whether the EPA has proven that the sequestration portion of the CCS system has been adequately demonstrated. EPA's arguments against the SAB conducting an independent peer review of the scientific and technical basis of the proposed rule violates several EPA policies (*Peer Review Policy*, *Peer Review Handbook (3rd Ed.)*, and *Scientific Integrity Policy*) and the President's *Memorandum on Scientific Integrity* (March 9, 2009).[12] As stated in EPA's *Scientific Integrity Policy*, "Independent peer review of Agency science is a crucial aspect of scientific integrity." Further, in the President's Memorandum, it states: "To the extent permitted by law, there should be transparency in the preparation, identification, and use of scientific and technological information in policymaking."

The President directed at 1(c) of the Memorandum, "When scientific or technological information is considered in policy decisions, the information should be subject to well-established scientific processes, including peer review where appropriate, and each agency should appropriately and accurately reflect that information in complying with and applying relevant statutory standards." The EPA's argument against the SAB conducting an independent review of the proposed rule deprived the public the right to have a law which is supported by sound science.

B. The Cost of Achieving Such Reduction

"Costs: The EPA considers whether the costs of the system are reasonable." 79 FR 1434.

Section 321 of the CAA requires that the Agency account for the employment effects which may result from administration of the CAA. The cost-benefit analysis relies upon conclusions which do not account for unemployment impacts of the proposed rule.

Since 2011, Kentucky's coal mines have lost 6,315 employees.[13] "Recent economic studies suggest that monetized cost of unemployment is significant, possibly more than $100,000 per worker. If agencies used this figure, there could be significant consequences for a wide variety of regulations." [14] Using the above monetized cost per worker, Kentucky is left with over $631.5 million in unemployment costs annually. While a portion of the loss is attributed to recent shifts to natural gas in the marketplace, the proposed rule will increase further job losses for the coal sector.

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[12] Mihelcic, James R., *Preparations for Chartered Science Advisory Board (SAB) December 4-5, 2013, Discussions of EPA Planned Agency Actions and their Supporting Science in the Spring 2013 Regulatory Agenda* (November 12, 2013), *Attachment C/Attachment 5.*

[13] Kentucky Quarterly Coal Report January 31, 2014. http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2013%20year%20end).pdf

[14] http://www.law.uchicago.edu/files/file/571-359-jm-eap-regulation.pdf

i. Exorbitant costs

EPA's conclusion that "a section of the industry is already accommodating the costs" of CCS is based on demonstration projects that receive DOE financial assistance. "DOE [...] has committed $2.2 billion for 5 projects to date." **79 FR 1478-79.** That financial assistance was available due to legislation that was passed to stimulate the economy during a recession by increasing spending in a specific time period. It is unreasonable to conclude that the costs of CCS are not exorbitant under circumstances when such funds are limited and will not be available indefinitely.

Specifically, the proposed regulation requires the use of partial CCS technology for new sources to be able to meet the emission standard. "EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant." *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999). Based on the most recent cost data associated with the Kemper and Edwardsport projects, the cost of installing and operating partial CCS is exorbitant.

According to Cabinet analysis, the levelized cost of electricity (LCOE) with CCS technology is higher than the LCOE without CCS technology.[15] Cabinet estimates indicate that the addition of CCS to either an IGCC or USCPC facility would increase cost per kWh by 40 percent to 58 percent respectively.[16]

In those two demonstration projects used by EPA, the actual costs accrued were much higher than the original cost estimates. The Edwardsport plant resulted in significant overrun costs of approximately $835M, for a total project cost of $3.5B. It is important to note that a settlement agreement between Duke Energy and the Indiana Office of the Utility Consumer Counselors resulted in a "Hard Cost Cap" of $2.595B for Indiana ratemaking purposes. Therefore, Indiana rate payers will shoulder the burden, considering that Duke Energy is responsible for the overrun costs of $900M.[17]

Currently, overrun costs at Kemper are estimated to be greater than $1.1B above the original estimate of $4.75B for the project. In a settlement agreement with the Mississippi Public Service Commission, Mississippi ratepayers are responsible for $2.4B of the plant's costs in traditional rates.[18]

It should be noted that the Department of Energy and National Energy Technology Laboratory (DOE/NETL) costs exclude transportation costs of CO_2, which could significantly increase the cost estimate for new sources implementing CCS technology. Section 111(a)(1) of the CAA

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[15] http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf
[16] See page 90 of
http://eec.ky.gov/Documents/Appendix%20C%20Electric%20Generating%20Report%20FINAL.pdf
[17] http://www.duke-energy.com/pdfs/Settlement-agreement-April-30-2012.pdf
[18] http://www.businessweek.com/ap/2013-07-01/miss-dot-power-says-more-overruns-likely-at-kemper

requires that EPA account for the "costs of achieving such reductions." Since EPA is proposing that CCS is the BSER for coal-fired EGUs, EPA must account for the cost of transporting CO_2.

In addition, the proposed regulation relies on the expected typical pipeline distance to be 50 miles to possible geologic sequestration sites. This distance underestimates the actual distances that may be necessary for the transmission of CO_2. EPA is required to comprehensively evaluate the impact of all associated transportation costs via pipelines, including availability and acquisitions of right-of-way for new pipelines, capital and operating costs, and actual length of transmission pipelines. **79 FR 1472**. Other costs, including the performance of expensive seismic studies, must be accounted for prior to a regulated entity being able to store CO_2 long-term.

Finally, EPA's economic analysis does not demonstrate how the proposed rule will alter future U.S. GDP, employment, and productivity. Kentucky has the most electricity-intensive economy in the U.S. since Kentucky industries use more kWh of electricity per GDP and are more sensitive to potential changes in electricity generation costs than any other state.[19] The loss of domestic manufacturing jobs will result from this proposed rule.

ii. Department of Energy and National Energy Technology Laboratory studies lack peer review

The DOE/NETL studies referenced in the new source performance standard (NSPS) rule included three reports. *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*, was initially released in May 2007. Although EPA conducted an internal peer review, there was not an external peer review of the 2007 report. The November 2010 update to the 2007 report did not go through an internal or external peer review process. A second report published in August 2011, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, modified the CO_2 capture rates for selected cases presented in the May 2007 report, but did not undergo a peer review. A third report that updated costs to 2011 dollars (August 2012 report) also did not go through a peer review process. EPA's failure to conduct external peer review for the reports in the DOE/NETL studies is contrary to EPA policies (*Peer Review Policy*, *Handbook on Peer Review (3rd Ed.)*, and *Scientific Integrity Policy*) and the President's *Memorandum on Scientific Integrity* (March 9, 2009).[20]

As a result, EPA has acted in an arbitrary and capricious manner and abused its discretion by failing to use peer reviewed sources for its cost and performance analysis.

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[19] Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf

[20] Mihelcic, James R., *Preparations for Chartered Science Advisory Board (SAB) December 4-5, 2013, Discussions of EPA Planned Agency Actions and their Supporting Science in the Spring 2013 Regulatory Agenda* (November 12, 2013), *Attachment C/Attachment 5.*

iii. Enhanced Oil Recovery (EOR) as Revenue Enhancement

"The EPA believes the cost of 'full capture' CCS without EOR is outside the range of costs that companies are considering for comparable generation and therefore should not be considered BSER for CO_2 emissions for coal-fired power plants...Full capture CCS has been estimated in the proposal to be in the range of $136/MWh to $147/MWh (without EOR benefits)." **79 FR 1435.**

"The EPA projects LCOE generation ranging from $92/MWh to $110/MWh, depending upon assumptions about technology choices and the amount, if any, of revenue from sale of CO_2 for EOR." **79 FR 1436.**

In fact, any requirement for use of CCS technology as proposed by EPA does not meet the cost criterion of BSER. In contrast, the proposal estimates the levelized cost of natural gas at $59/MWh to $86/MWh, depending upon assumptions about natural gas prices. **See 79 FR 1435.**

Further, Kentucky has little opportunity for EOR applications. The Kentucky Geological Survey (KGS) summarized that, "CO_2 EOR has benefits in Kentucky, but the benefits will need to be weighed in light of the cost of CO_2, the shallow depth of our oil fields, aging well bores, and the need for pipeline infrastructure to transport CO_2." KGS also found that "because of the costs involved with deep permanent storage, CO_2 enhanced oil recovery is being considered as an alternative" and that "storing the volume of CO_2 released from a coal-fired power plant will still be a large and expensive undertaking." [21] These findings were based on the Hancock County, Kentucky, test well. KGS found that:

> "A well like the Hancock County well may be capable of injecting 1,000 tons of CO_2 per day. If all the CO_2 were captured, a plant like Big Sandy (6 million tonnes/year) would require 16-20 injection wells, while Paradise (13.5 million tonnes/year) would require double that number. Based on the volume of pore space we found, each million tons of CO_2 would occupy approximately 250 acres of land area (about a third of a square mile)."[22]

The proposed rule has nationwide applicability and the fact that EOR seldom occurs in Kentucky prevents EGUs located in the state from relying on EOR to defray the costs of implementing CCS. Without that reduction in costs, CCS is not economically feasible. According to the Carbon Storage Research performed by the Kentucky Geological Survey, "immiscibility between CO_2 and oil will be [the] prevailing condition in most Ky. Reservoirs (~90%) and limit EOR effectiveness."[23]

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[21] *Testimony and facts sheets from David C. Harris*, Energy and Minerals Section, Kentucky Geological Survey to Kentucky House of Representatives Natural Resources and Energy Committee, January 23, 2014.

[22] *Testimony and facts sheets from David C. Harris*, Energy and Minerals Section, Kentucky Geological Survey to Kentucky House of Representatives Natural Resources and Energy Committee, January 23, 2014.

[23] *CO_2-Enhanced Oil Recovery (EOR) Pilot Projects Fact Sheet*, Kentucky Geological Survey.

There is no specific authority in the CAA to require a regulated entity to engage in a separate energy process (EOR) to defray costs associated with a mandated system of pollution control. In fact, establishing a standard reliant upon emission impacts obtained pursuant to regulatory requirements that are the result of aggravated offsite activities appears contrary to the recent Sixth Circuit Court of Appeals holding in *Summit Petroleum Corporation v. US EPA,* 690 F.3d 733 (6th Circuit; 2012). Regardless of whether EOR is available, CCS will necessarily require a process that is expensive. It will create exactly the "'fine-grained' and administratively burdensome result the EPA sought to avoid in its drafting of its Title V stationary source test [...]" *Id.* at 733, 751.

The total amount of CO_2 necessary for EOR nationwide will be provided by a limited number of facilities. In a project summary, DOE/NETL cites that, "[t]he CO_2 storage capacity of depleted oil reservoirs and saline formations in Citronelle Dome was estimated by static calculations to be between 0.5 and 2 billion short tons of CO_2, sufficient to sequester the CO_2 from a nearby 1500 MW (electric) coal-fired power plant for 35 years."[24] If the regulated industry as a whole does not have EOR as a means of reducing costs, CCS cannot be deemed adequately demonstrated to achieve a standard that may apply to the industry as a whole. Therefore, EPA eliminates new opportunities for coal-fired EGUs in states where EOR is not readily available.

iv. Geographic limitations

The D.C. Circuit Court has ruled that Section 111 of the CAA standards "must not give a competitive advantage to one State over another in attracting industry." *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 918 (D.C. Cir., 1990). Geological features necessary for EOR and sequestration are not evenly distributed throughout the country. As a result, the proposed regulation will have significant disparate geographic impacts. The implementation of the system for pollution control must not be dependent on geographical distinctions, such as EOR, geological formations for storage capability, and feasibility of installing pipelines for CO_2 transportation.

This consideration should be compared to EPA's rationale for choosing partial CCS as BSER, "[...] section 111 emission limits based on a particular type of technology and for economic or technical reasons, sources are able to utilize that technology in only certain parts of the country and not other parts, that result should not be viewed as inconsistent with Congressional intent for CAA Section 111." **79 FR 1467.** If the emission standards are established as proposed, Kentucky and many other states will be at a significant competitive disadvantage to other states due to the challenges of partial CCS.

The Cabinet disagrees that "[T]he inability of some coal-fired sources to locate in certain areas would not create reliability problems or prevent the satisfaction of overall demand for electricity." **79 FR 1467.**

EPA must identify and practically address the conflict between the inability of some fossil fuel-fired EGUs to locate in certain areas and the legislative intent behind the NSPS to

[24] http://www.netl.doe.gov/research/oil-and-gas/project-summaries/enhanced-oil-recovery/43029co2prod

encourage the use of local fuels.[25] EPA must also consider increased fuel transportation costs and increased electricity transmission costs incurred by locating an EGU facility proximate to geologic formations favorable to CO_2 sequestration.

Furthermore, recent winter weather events dramatically demonstrate that there will always be a need and demand for reliable, cost-effective sources of electricity, such as coal. Therefore, the narrowing of energy options by this proposed rule is inconsistent with President Obama's all-of-the-above energy strategy and is detrimental to national security and to the economies of Kentucky and the nation.

C. Size of Emission Reductions

"Size of emission reductions: The EPA considers the amount of emissions reductions that the system would generate." 79 FR 1434.

The proposed regulation uses the term "meaningful reductions in emissions" without setting a specific regulatory threshold to appropriately and adequately define what constitutes meaningful reductions. In the absence of a specific ambient target or emissions reduction target, the term is vague and meaningless. Relying upon it as the basis for the established standard is arbitrary and capricious.

The proposed regulation provides no scientific basis for why an emission rate achieved by the most recent commissioned EGUs with an annual average emission rate of 1,700 $lbsCO_2/MWh$ does not result in "meaningful reductions" of CO_2 as opposed to current national average emission rate for coal-fired units of 2,100 $lbsCO_2/MWh$[26]. As previously stated, this emission limit would reduce CO_2 emissions greater than 19 percent from the current national average, resulting in "meaningful reductions."

D. Technology Implementation and Further Development

"Technology: The EPA considers whether the system promotes the implementation and further development of technology." 79 FR 1434.

"Determining that these high efficiency generating technologies represent the BSER for CO_2 emissions from coal-fired generation would fail to promote the development and deployment of CO_2 pollution-reduction technology from power plants. In fact, a determination that this efficiency enhancing technology alone, as opposed to CCS, is the BSER for CO_2 emissions from new coal-fired generation likely would inhibit the development of technology that could reduce CO_2 emissions significantly, thus defeating one of the purposes of the CAA's NSPS provisions." **79 FR 1435.**

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[25] *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 918 (D.C. Cir., 1990).

[26] 2013 EPA's *Clean Air Markets Division (CAMD)* data.

EPA must not rely upon a factor which is not expressed in the statute (technological innovation; **79 FR 1462.**) to force implementation of a technology that has not been adequately demonstrated or to establish a standard that is not feasible. EPA must ground its reasons for action or inaction in Section 111(b) of the CAA. *Mass. v. EPA*, 549 U.S. 497 (2007). Section 111(b) of the CAA was intended, in effect, to require "maximum feasible control of pollutants from new stationary sources through technology based standards." **40 FR 53340.** Additionally, Section 111(b) of the CAA requires that EPA take into consideration that it must account for "the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements" when selecting BSER. 42 U.S.C.A. 7411(a)(1).

There is a clear distinction between technology forcing and encouraging technological innovation. The proposed rule is unnecessary to promote technologies in this context. For example, Section 111(j) of the CAA specifically provides for the promotion, development, and deployment of innovative technological systems of continuous reduction for technologies like CCS that have not been adequately demonstrated. Additionally, Section 103(g) of the CAA provides EPA with the authority to conduct a basic engineering research and technology program to develop non-regulatory technologies and strategies, to be developed with priority on those pollutants which pose a significant risk to human health and the environment, and that section refers specifically to "carbon dioxide, from stationary sources, including fossil fuel power plants." However, the proposed rule sets a standard which forces the use of an experimental, currently infeasible technology, a factor that is not implicit in Section 111(b) of the CAA or explicit within the statute. The proposed rule, which relies upon technology forcing to justify the proposed standard, exceeds relevant authority.

E. Conclusion to BSER

"After considering these four factors, we propose that efficient generation technology implementing partial CCS is the BSER for new affected fossil fuel fired boilers and IGCC units (subpart Da sources) and modern, efficient NGCC technology is the BSER for new affected combustion turbines (subpart KKKK sources)." **79 FR 1434.**

The Cabinet finds that CCS technologies are not yet fully mature, not utilized by this industry or fuel type on a commercial scale, and thus, not adequately demonstrated. Thus, the selection of CCS as BSER for coal-fired EGUs is arbitrary and capricious.

The proposed rule implies IGCC with CCS is well-established and already in widespread commercial practice in the United States. This is absolutely inaccurate. The demonstration projects that the EPA relies on in its determination are not in operation. Further, the proposed rule does not explain all of the original estimates for construction costs of those projects, the actual costs of construction to date, whether construction deadlines have been met, the types of carbon sequestration that will be used with the plants, the amount of subsidies the plant owners receive from DOE and whether they are utilizing EOR and other product streams to defray costs and if so, to what extent.

VIII. Implications for Air Quality Control Agencies

A. Permitting Issues

The proposed rule improperly uses gross output as the basis for the standard and the proposed structure of regulatory applicability for co-generation units. The standard as currently written is proposing to "add additional criteria to be met in addition to the 'constructed for the purpose of supplying more than one-third of its potential electric output capacity' to the grid." **79 FR 1445.**

i. Applicability of "constructed for the purpose of."

40 CFR 60.5509(a) specifies the applicability for stationary combustion turbines is conditional based on:

> "[...] a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average."

As written, if the facility declares that the purpose of the unit is to supply less than one-third of its potential output, the conditions following the phrase are without meaning because all of the conditions are connected with "and." If any one of the conditions is not true, then the regulation is not applicable.

Permitting authorities must not be put in the position of trying to determine if the purpose of a source is to use one-third or more of its output for a particular purpose. The Cabinet recommends that phrase "constructed for the purpose of" be deleted.

ii. The averaging period should be the same for all fuels and combustion devices.

EPA has not adequately documented why steam generating units or IGCC outputs are based on an annual basis while combustion turbines are based on a 3-year average. EPA explains its rationale at **79 FR 1445**, which appears to be to accommodate the possibility that peaking units may need to occasionally supply energy for longer periods during an emergency. The averaging period should be the same regardless of unit type and fuel. The Cabinet recommends a 3-year average before triggering applicability of the rule to allow for usage during emergencies regardless of the type of unit, purpose, or fuel.

iii. Combustion turbines using liquid fuels should be subject to the proposed rule.

"Oil-fired stationary combustion turbines, including both simple and combined cycle units, are not subject to these proposed standards. These units are typically used only in areas that do not have reliable access to pipeline natural gas (for example, in non-continental areas)." **79 FR 1446.**

EPA has not adequately documented why the proposed rule is applicable to liquid fuel when combusted in steam generating units or IGCC units, but not when combusted in combustion turbines. The fact that liquid fossil fuels are rarely used in combustion turbines currently is not determinative of future use. Liquid fuels usage is based on economics rather than technical limitations, which will necessarily change if the proposed regulation goes into effect as written.

At a minimum, if liquid fossil fuels are exempt from the proposed regulation, it will make them more cost-effective than they currently are compared to fuels that are subject to the regulation. Another way that the proposed regulation itself will change the feasibility of liquid fuels is the need for many power stations to have on-site fuel storage. Natural gas is not as easily stored on site as are coal and liquid fuel. In fact, there are simple cycle combustion turbines in Kentucky that are designed to operate on both natural gas and fuel oil for reliability purposes. Fuel oil is stored on site in the event of natural gas curtailments or other disruptions of fuel supply.

B. Best Available Control Technology (BACT)

The Cabinet disagrees with the EPA's assessment as stated below:

> "Furthermore, this proposal does not have any direct applicability on the determination of Best Available Control Technology (BACT) for existing EGUs that require PSD permits to authorize a major modification of the EGU." **79 FR 1487.**

This statement is in direct contradiction with EPA's determination that BACT can be no less stringent than an NSPS; thus, the setting of NSPS does establish the "BACT floor":

> "Furthermore, this definition in the CAA specifies that '[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.' This has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS." **79 FR 1489.**

In EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001, March 2011), EPA notes regarding the availability of CCS technology for the determination as an add-on control for BACT purposes:

> "Thus, even if technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be

> considered 'available' as that term is used for the specific purposes of a BACT analysis under the PSD program."

However, even if CCS is considered "available" for BACT purposes it may not be found to be "technically feasible," as detailed in the Guidance. EPA cites the *Report of the Interagency Task Force on Carbon Capture and Storage* that concluded:

> "Current technologies could be used to capture CO_2 from new and existing fossil fuel energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[27]

In regard to technical feasibility, "EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[28] Through this rulemaking, EPA has not provided sufficient and adequate technical support documentation to alter its previous determination that CCS is not "technically feasible" as stated in 2011.

Considering the inter-relationship between BACT determinations and "proposed" NSPS, EPA must establish NSPS applicable requirements consistent with previous BACT determinations and EPA's PSD Guidance document referenced above.

C. Compliance Requirements

To the extent possible, all monitoring, recordkeeping, and reporting requirements should be streamlined and consistent with other applicable air quality programs, such as the Acid Rain program.

"[U]nder our proposed approach, new fossil fuel-fired boilers and IGCC units would be required, based on the performance of currently available CCS technology, to meet a standard of 1,100 lb CO_2/MWh on a 12-operating-month rolling average, or alternatively a lower—but equivalently stringent—standard on an 84-operating-month rolling average, which we propose as between 1,000 lb CO_2/MWh and 1,050 lb CO_2/MWh. The EPA has previously offered sources optional, longer-term emission standards that are discounted from the primary emissions standard in combination with a longer averaging period." **79 FR 1448.**

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[27] *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001, March 2011) at 32. See also, *Report of the Interagency Task Force on Carbon Capture and Storage*, pg. 50 (http://www.epa.gov/climatechange/policy/ccs_task_force.html.)
[28] *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001, March 2011) at 36.

Enforcement of the 84-operating month rolling average is problematic, as the duration of an operating permit issued under 40 CFR Part 70 or 71 is five (5) years. The 84-month averaging period beyond the permit term would impact a permitting agency's ability to determine and enforce compliance.

Periods of Startup, Shutdown and Malfunctions

"The NSPS that the EPA is proposing in this action would apply at all times, including during startups and shutdowns." **79 FR 1488.**

The Cabinet expresses serious and significant concerns regarding the practical ability to monitor emissions during periods of startup, shutdown and malfunctions.

IX. Separation of Powers

The proposed standards render new coal-fired power plants so cost-prohibitive that they are effectively regulated out of the nation's energy generation fleet. Section 111 of the CAA does not authorize EPA to establish energy policy inconsistently with Congressional intent. Setting energy policy in this manner violates the separation of powers doctrine.[29] Thus, the proposed rule is inconsistent with the well-established, customary interpretation and application of Section 111 of the CAA, which has been to implement Congressional policy to set achievable environmental standards and was never intended as a legislative vehicle to establish energy policy.

X. Energy Policy Act (EPAct)

The projects in the electricity generation industry relied upon by EPA in the proposal are either federally funded pursuant to EPAct statutes[30] or funded by the Canadian Government[31] and not in operation. The proposed regulation lists Federal tax subsidies available for many types of electricity generation. **79 FR 1479.** However, the proposed regulation fails to mention Section 48A of the Internal Revenue Code. Section 48A(g) states that:

> "No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this

[29] *Federal Power Commission v. Texaco*, 417 U.S. 380, 400, 94 S.Ct. 2315, 41 L.E.d.2d 141 (1974).
[30] Thus, they may not be relied upon as the basis for determining that CCS is adequately demonstrated or for setting the proposed standard.
[31] The Boundary Dam project received roughly 20 percent of its funding from the Canadian government, is sized at 100MW rather than 300MW due to the exorbitant escalating cost, is not in operation, and has experienced significant cost overruns. http://sequestration.mit.edu/tools/projects/boundary_dam.html. The fact that all commercial scale projects cited by EPA receive substantial government funding demonstrates that it is unreasonable for the Agency to conclude that selecting CCS as BSER is "reasonable because a segment of the industry is already accommodating the costs." **79 FR 1478.**

> section, shall be considered to indicate that the technology or performance level is [...] adequately demonstrated for purposes of section 111 of the Clean Air Act." *Energy Policy Act of 2005* (Public Law 109-58) §1307(b); codified at 26 U.S.C. §48A(g).

Additionally, the Cabinet notes that the *Notice of Data Availability* (NODA) and *Technical Support Documents* (TSD), included in the Docket at EPA-HQ-OAR-2013-0495 on February 6, 2014, raise significant new issues, discuss subsequent Agency interpretations, and rely upon "additional evidence" not included in the docket when the rule was promulgated. To provide for adequate comment on the actual basis of the determinations in the proposed rule, this conflict must be resolved consistently with the President's directive that the Agency "(vi) work with the Department of Energy and other Federal and State agencies to promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency [...]." 78 FR 39535.

XI. Significant Energy Action

"This proposed action is not a 'significant energy action' as defined in Executive Order 13211[...] because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This proposed action is anticipated to have negligible impacts on emissions, costs, or energy supply decisions for the affected electric utility industry." RIA[32] at 6-10.

The Cabinet strongly disagrees with EPA's determination that this proposal is not considered as a "significant energy action." The proposed rule would result in significant adverse effects on the supply, distribution, and use of energy, and should be considered a "significant energy action," as defined in *Executive Order 13211*[33] and the implementing *OMB Memorandum 01-27*.[34]

According to *OMB Memorandum 01-27* regarding implementation of *Executive Order 13211*, a "significant adverse effect" includes, among other things:

1. **Reductions in coal production in excess of 5 million tons per year;**

Since 2008, Kentucky coal production has decreased by 40.3 million tons to 80.7 million tons, the lowest level since 1963.[35] Further, U.S. production decreased 188 million tons. By prohibiting construction of new coal-fired power plants, the proposed rule will cause further decline in coal production.

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[32] *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units* (EPA-452/R-13-003, September 2013).
[33] 66 FR 28355.
[34] http://www.whitehouse.gov/omb/memoranda_m01-27
[35] *Kentucky Quarterly Coal Report*, January 31, 2014.
http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2013%20year%20end).pdf

2. **Reductions in electricity production in excess of 1 billion kilowatt-hours per year or in excess of 500 megawatts of installed capacity;**

Cabinet analysis shows, with moderate to high probability related to known and projected coal-fired EGU retirements, 81 GW of coal-fired electricity generating capacity nationwide will be retired.

3. **Increases in the cost of energy production in excess of one percent; or**

Cabinet estimates indicate that the addition of CCS to either an NGCC or USCPC facility would increase cost per kWh by 40 percent to 58 percent respectively. [36] Partial CCS with EOR would result in a 13 percent increase in the cost of electricity from a baseline of zero CCS, according to the Clean Air Act Task Force. [37] By establishing partial CCS as the BSER for new coal-fired power plants, the proposed rule would have an adverse effect on the price of electricity in Kentucky and many other states.

4. **Increases in the cost of energy distribution in excess of one percent.**

The Interstate Natural Gas Association estimates that, through 2035, the United States and Canada will need 600 miles per year of new lateral lines to and from natural gas-fired power plants, processing facilities, and storage fields, 1,400 miles per year of new gas transmission mainline, and 16,500 miles per year of new gathering lines in order to meet infrastructure needs.[38] Collectively, the natural gas, NGL, and oil midstream sector will require total capital expenditures of $10 billion per year or a total of $251.1 billion (Real 2010$) through 2035.

Further, the memorandum[39] details that a regulatory action could also have significant adverse effects if it, among other things:

1. **Adversely affects in a material way the productivity, competition, or prices in the energy sector;**

This regulatory action eliminates coal-fired electric generating units from the competitive marketplace. (Please refer to *Section IV. Redefines and Mandates the Basic Fundamental Design of EGUs and Section V. Fuel Switching.*)

2. **Adversely affects in a material way productivity, competition or prices within a region;**

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[36] See page 90 of http://eec.ky.gov/Documents/Appendix%20C%20Electric%20Generating%20Report%20FINAL.pdf
[37] See Figure 1 of http://www.catf.us/resources/whitepapers/files/20121220-How_Much_Does_CCS_Really_Cost.pdf
[38] http://www.ingaa.org/File.aspx?id=14911
[39] http://www.whitehouse.gov/omb/memoranda_m01-27

For coal-fired units, this regulatory action mandates partial CCS technologies that are not available in all geographic areas. (Please refer to *Section VII.B.iv. Geographic limitations.*)

3. Creates a serious inconsistency or otherwise interfere with an action taken or planned by another agency regarding energy; or

This regulatory action is not consistent with the clean coal technology programs administered by Department of Energy. (Please refer to *Section VII.B.ii. Department of Energy and National Energy Technology Laboratory studies lack peer review.*)

4. Raises novel legal or policy issues adversely affecting the supply, distribution or use of energy arising out of legal mandates, the President's priorities, or the principles set forth in *Executive Order No. 12866* and *13211.*

This regulatory action creates regulatory uncertainty and raises the legal issues of the statutory definitions of "adequately demonstrated" and "new source" and their application. (Please refer to *Section VII.A.i. Legal arguments.*)

The construction of the text in the memorandum only requires one condition to be satisfied. As a result, EPA is required to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget due to the fact that the rulemaking significantly affects the supply, distribution, and use of energy.

XII. Regulatory Impact and Economic Analysis

"CAA Section 111(b) requires that the new source performance standards (NSPS) be reviewed every eight years. As a result, this rulemaking's [economic] analysis is primarily focused on projected impacts within the current eight year NSPS timeframe" RIA at 1-2.

Even though the statutory review time for a NSPS is eight (8) years, EPA erred by limiting "[...] the expected economic impacts of the proposed EGU New Source GHG Standards rule through 2022." RIA 2-1. Energy Information Administration (EIA) natural gas price forecasts have been historically inaccurate. Even so, these forecasts show natural gas prices to the electric power sector to more than double by 2040, at an average rate of 3.1 percent per annum. During the same time period, the EIA anticipates that coal prices are expected to rise at only 1 percent per annum. The Cabinet's analysis has determined that coal-fired electricity generation will become the least-cost generating option beyond the 2022 analysis timeframe.

The proposed rule will generate significant costs beyond 2022 by prohibiting the least-cost generating option, coal-fired electricity generating units. It is disingenuous for the EPA to intentionally apply an eight-year time frame for its economic analysis when the utility sector's business decision making model utilizes a 30-60 year planning and investment horizon. The EPA is improperly proposing to implement a policy with long-term consequences based upon a short-term analysis.

The RIA states that the proposed rule will have no changes on EGU business decision-making methodology. Thus, the proposed rule has no costs or benefits based on the assumed LCOE. This absurd assumption creates a false conclusion that no new coal-fired power plants will be built in the analysis timeframe. Independent modeling by the Cabinet establishes this assumption to be robust at levelized natural gas prices up to $8.00 per MMBtu, contrary to the RIA claim of robustness up to $10 per MMBtu. However, the RIA LCOE for SCPC, in Kentucky, is 11.7 percent higher than independent Cabinet estimates but within 2.5 percent for NGCC estimates. This suggests a bias for NGCC by inflating the LCOE of SCPC as a result of not considering regional cost differences in the LCOE.

Finally, the proposed rule relies on results from an Integrated Planning Model (IPM) that projects an abundance of natural gas and a continued decline in natural gas prices. The Cabinet questions whether the IPM model accounted for the effects on natural gas prices and availability resulting from future EPA rulemaking for the production and processing of natural gas (such as fracturing or "fracking" rules) or the impacts of natural gas exports.

A. Economic Analysis

The RIA does not estimate the consumer sensitivity to changes in electricity prices or the price elasticity of demand. As noted in the RIA:

> "EPA modeling does not typically incorporate a 'demand response' in its electric generation modeling to the increases in electricity prices... electricity demand is considered to be a constant in EPA modeling applications." RIA at 4-34.

The Cabinet's modeling clearly demonstrates that changes in electricity prices are associated with second-order economic implications, including changes in employment and economic growth. [40] These second-order costs of environmental policy frequently outweigh the costs of actual compliance.

"EPA also does not anticipate this rule will have any impacts on the price of electricity, employment or labor markets, or the US economy." RIA at 1-4. However, the Cabinet has determined that, by preventing least-cost resources beyond 2022, this proposed rule will exacerbate the forecasted 25 percent increase in the real price of electricity in Kentucky between 2011 and 2025. This will result in the loss of, or failure to, create approximately 30,000 full time jobs, with Kentucky's manufacturing sector being the most responsive to these changing prices. A proper long-term policy impact analysis should account for price elasticity, employment effects, the potential loss of energy-intensive manufacturing and heavy industry, and regional economic impacts.

[40] See "The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices", http://energy.ky.gov/Programs/Documents/Vulnerability%20of%20Kentucky%27s%20Manufacturing%20Economy.pdf

The EPA has not incorporated risk assessment into its economic analysis. The EPA has not finalized its evaluation of hydraulic fracturing as a means of extracting natural gas and natural gas liquids (NGLs). If future EPA regulations result in natural gas and NGLs becoming uneconomical in the marketplace, then without coal-fired generation, the economic consequences are potentially devastating for the United States. Private investment capital lenders and bond rating agencies require that electric generating utilities perform a risk assessment before committing to large-scale capital investment projects. The EPA exacerbates market uncertainty and adds to cost by not providing sufficient completeness in its analyses and utility risk assessment models. The EPA must include a risk assessment as part of the regulatory impact analysis to account for pending regulatory actions, many of which will affect the construction and operation of fossil fuel-fired power plants. In addition, the EPA has not accounted for the increased threat to national security that accompanies the move to natural gas due to enhanced pipeline vulnerability.

EPA's *Guideline for Preparing Economic Analysis* states that:

> "Social cost represents the total burden that a regulation will impose on the economy. It is defined as the sum of all opportunity costs incurred as a result of a regulation where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of a regulation." RIA at 8-1.

EPA's social cost analysis as presented in the RIA is incomplete. The analysis is deficient in addressing the secondary price effects corresponding to the increased opportunity costs of goods produced in manufacturing intensive states, like Kentucky. Cabinet modeling suggests that a 10 percent increase in the real price of electricity would, on average, be associated with a 1.1 percent reduction in state GDP.[41] This would result in a loss of almost $2 billion dollars to the state of Kentucky.[42] EPA's analysis should reflect what portion of GDP loss is due to the proposed rule's effect on market conditions. In fact, EPA has already recognized this deficiency by requesting comment on the role of economy-wide modeling in U.S. EPA analysis of air regulations. **79 FR 6899.**

Manufacturing states, like Kentucky, have high electricity intensity, ~ 0.5 kWh/$SGDP, while primarily consumer states like New York and California are low, ~0.13 kWh/$SGDP.[43] EPA's analysis should reflect the likely consequence of manufacturing states having increased electricity costs resulting in less heavy industry and manufacturing in the regional economy and in the United States than currently exist. For example, electricity-intensive industries such as primary metal manufacturing, which have been leaving the United States during the past decades, are currently clustered in states like Kentucky where electricity costs have remained

[41] See presentation on "The Relationship between Electricity Prices and Economic Output" http://energy.ky.gov/Programs/Documents/Model%20of%20electricity%20prices%20and%20economic%20output.pdf

[42] See *Kentucky Demographic Profile* http://www.thinkkentucky.com/kyedc/pdfs/KYDemographicProfile.pdf

[43] See Page 3 of *Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act* http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf

low. If these companies migrate to countries with less stringent environmental regulations, the net effect of the rules would be economically disadvantaged state and regional economies, further unemployment, and worsening of the trade deficit if those same goods, previously made in the United States, are now imported. The result is migration that diminishes the regulatory benefit, threatens U.S. GDP, and compromises national security by lessening U.S. independence within the manufacturing sector. Further, there is no net reduction of global CO_2 emissions; in fact, global CO_2 emissions will likely increase.

B. Climate Uncertainty Adder

The RIA states that: "Additionally, it is important to note that both EIA and EPA apply a climate uncertainty adder (CUA) – represented by a three percent increase to the weighted average cost of capital – to new, conventional coal-fired capacity types." From the EIA footnote in the RIA regarding CUA:

> "While the 3-percentage point adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, similar to the costs used by utilities and regulators in their resource planning. The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions. As a result, the levelized capital costs of coal-fired plants without CCS are higher than would otherwise be expected." RIA at 5-21.

In addition, the RIA also states that: "All LCOE estimates of coal-fired facilities with CCS (partial or full) are presented without the CUA." RIA at 5-22. The CUA should be applied to all generation types that emit CO_2, including partial CCS and all natural gas generating technology. Furthermore, the use of the 3 percent CUA is arbitrary and likely quite low.

C. Social Cost and Benefit Analysis

The RIA utilizes the social cost of carbon (SCC) and states "The federal government typically uses the SCC to estimate the social benefits of CO_2 reductions from regulatory actions that impact cumulative global emissions." RIA at 5-36. The use of the SCC overinflates the social benefits of the proposed rule. The SCC is modeled to estimate the global benefit of CO_2 reductions, wherein the proposed rule is specific to U.S. EGUs. Therefore, the social benefits calculated by EPA should represent those specific to the U.S. rather than worldwide. This is also contrary to OMB Guidance as stated in the *SCC Technical Support Document*[44], "Under current OMB guidance contained in *Circular A-4*, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international

[44] See p.10 http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf

perspective is optional". The Interagency Working Group on Social Cost of Carbon[45] in 2010 "determined that a range of values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects."

Furthermore, *OMB Circular A-94* states that as a default position, a discount rate of 7 percent should be used as a base-case for regulatory analysis. A 7 percent discount rate is conspicuously absent from EPA analysis in regard to SCC. The rate at which EPA discounts future impacts (both positive and negative) into present monetary terms has enormous impact on the estimated SCC to the point of misleading policymakers on the true cost-benefit impacts of this proposed regulation.[46]

The RIA states:

> "Only the direct emissions of CO_2, SO_2, and NO_X are considered in this illustrative exercise. Other air and water pollutants emitted by these technologies and emissions from the extraction and transport of the fuels used by these technologies are not considered. For example, coal has higher mercury emissions than natural gas, but the relative benefits from the difference in mercury emissions are not considered. Furthermore, there may be differences in upstream greenhouse gas emissions (in particular, methane) from different technologies but those were not quantified for this assessment." RIA at 5-42.

By not including GHG impacts from fossil fuel extraction and transport, EPA's analysis of health and welfare impacts is incomplete. The proposed rule relies on EIA forecasts that indicate natural gas preference over coal within the eight-year NSPS time frame. Recent studies suggest that lifecycle climate effects of shale gas are worse than coal over a 30-50 year timeframe and draws serious questions to its use as a transitional fuel to more renewable sources. [47] Thus, lifecycle GHG emissions from increased natural gas production and transportation should be included in EPA cost-benefit analysis including health and welfare impacts.

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[45] See p.11 http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf

[46] *Written Testimony*, the Senate Committee on Environment and Public Works http://www.epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=d74255e9-6a8a-473f-82a3-ff19921798ef

[47] http://www.postcarbon.org/report/390308-report-life-cycle-greenhouse-gas-emissions