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American Coalition for Clean Coal Electricity Comments on EPA's Proposed Performance Standards for Greenhouse Gas Emissions from New Fossil-Fueled Electric Utility Generating Units

The American Coalition for Clean Coal Electricity (ACCCE) submits the following comments on the Environmental Protection Agency's January 8, 2014 proposed "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" ("New Source Performance Standards" (NSPS) or "standards"). ACCCE is a national trade organization comprised of industries involved in producing electricity from coal. A list of ACCCE board members is attached as Appendix 1. In addition to our comments, ACCCE is a member of the Utility Air Regulatory Group and the Coal Utilization Research Council and endorses the comments of those groups.

ACCCE supports reasonable and balanced environmental policies that ensure affordable, reliable, domestically produced energy. However, ACCCE is opposed to regulating carbon dioxide (CO_2) emissions under the Clean Air Act (CAA or Act). The CAA was not designed to regulate CO_2 and other greenhouse gases (GHGs) and does not provide an effective or legally viable framework for addressing concerns about global climate change. However, because EPA has proposed such regulations, ACCCE is providing comments that urge EPA to abandon its unreasonable proposal and adopt standards that are consistent with the CAA and do not foreclose the use of coal for future baseload electricity generation.

Coal is our nation's most abundant domestic fossil fuel energy resource and, for that reason, plays a crucial role in providing electricity to consumers in virtually every state in the nation. Coal provides more than one quarter of the electricity in 31 states with a collective population of more than 184 million people. EPA regulations have contributed, so far, to the retirement or conversion of 380 existing coal units totaling over 51,000 megawatts of electric generating capacity in 33 states. These retirements pose increasing reliability challenges for the electricity grid and leave consumers exposed to higher energy prices. Unfortunately, coal retirements could continue because of EPA's forthcoming CO_2 regulations for existing power plants under section 111(d) of the CAA, as well as other pending EPA policies.

To assure the continued use of coal for electricity generation, ACCCE urges EPA to adopt reasonable and achievable CO_2 standards based on adequately demonstrated technology. Such standards would reduce CO_2 emissions and allow the construction of new high efficiency coal-fueled power plants when market conditions support new coal plants.

Executive Summary

On January 8, 2014, EPA proposed to adopt CO_2 performance standards for new fossil-fueled power plants.[1] EPA proposed a standard of 1,100 pounds CO_2/megawatt-hour (lbs CO_2/MWh) for new coal-fueled power plants based on partial CO_2 capture. In setting such a standard, EPA proposed to determine that carbon capture and storage (CCS) is "adequately demonstrated" and is the "best system of emissions reduction," the statutory requirements of the CAA.[2]

ACCCE supports EPA's decision in this proposal to set separate performance standards for coal-fueled power plants and natural gas-fueled power plants. However, EPA should not base the standard for coal on CCS technology for the following reasons:

- The plain language of the CAA does not allow for the consideration of emerging and unproven emissions control technologies. CCS is an emerging and unproven technology and, therefore, cannot be considered in setting the NSPS.
- EPA's proposal relies on projects that received government funding under the Energy Policy Act of 2005 (EPAct05) to assert that CCS is "adequately demonstrated." However, EPAct05 expressly prohibits EPA from setting a standard under 111(d) based on projects funded by certain EPAct authorized programs.
- The Administration noted in its National Climate Assessment (NCA), that CCS is "still in the early phases of development." The NCA, in discussing CCS, highlights the fact that "many uncertainties remain, including cost, demonstration at scale, environmental impacts, and what constitutes a safe, long-term geologic repository for sequestering carbon dioxide."
- EPA's determination that CCS is adequately demonstrated conflicts with its own permitting decisions. These permits have determined that CCS is neither demonstrated at a utility scale nor a cost-effective commercially available technology for new coal-fueled power plants.
- EPA has not shown that major CO_2 transportation and storage challenges have been resolved. For example, enhanced oil recovery (EOR) is a regionally constrained CO_2 storage opportunity, and assignment of long-term liability for CO_2 injected into saline formation remains unresolved in many places.
- CCS is exorbitantly costly. EPA has significantly underestimated the cost of CCS by misinterpreting Department of Energy cost estimates and has failed to recognize the first-of-a-kind nature of CCS costs. Currently, the addition of CCS to a single new coal-fueled electric generating unit costs in the range of $1 billion.
- The proposed NSPS will serve as a disincentive for future industrial participation in CCS demonstrations and stop CCS technology development. Currently, proposed CCS demonstration projects will integrate costly first generation CCS technology. New coal-fueled power plants will need to be built so that less expensive and more cost-effective second generation CCS

demonstrations can occur. Because the proposed NSPS will effectively ban new coal-fueled power plants, second generation CCS will likely never be demonstrated in the U.S.

While CCS is a promising CO_2 emissions control technology, it has not been demonstrated at scale and remains very costly, as shown by the limited and unique circumstances in which the technology has been deployed.

In light of the major problems listed above, EPA should withdraw the proposed NSPS. If EPA still believes that NSPS are necessary and legally justified, the agency should develop standards for power plants that are consistent with the CAA and based on sound energy and economic policy. Specifically, we urge EPA to set standards based on CO_2 emissions rates achieved by recently built and highly efficient coal-fueled power plants, especially supercritical and ultra-supercritical units, without CCS. Based on an analysis of recently built coal-fueled power plants, we recommend EPA set the following emissions rates:

- 1,915 lbs CO_2/MWh for supercritical boilers burning bituminous and subbituminous coals;
- 2,080 lbs CO_2/MWh for subcritical boilers burning bituminous and subbituminous coals; and
- 2,150 lbs CO_2/MWh for all boilers burning lignite coals.

Such an approach would help assure an adequate supply of reliable, affordable electricity by allowing all energy resources – including coal – to compete on a level playing field based on market dynamics, not environmental ideology.

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I. EPA should set CO_2 emissions standards for new coal-fueled power plants that are achievable and based on new highly efficient coal-fueled power plants.

CCS, as discussed in greater detail below, is not "adequately demonstrated" for full-scale electric power generation. Several types of lower CO_2-emitting coal-fueled electric power generation technologies are adequately demonstrated for full-scale application at new coal-fueled power plants. Supercritical pulverized coal and ultra-supercritical pulverized coal have been successfully demonstrated at full scale in U.S. power plants and can significantly lower CO_2 emissions as compared to the typical existing coal-fueled power plant. Other countries, such as Japan, China and Germany, recognize the important role of coal in providing affordable and reliable electricity to their economies.[3]

Achievable CO_2 emissions levels from recently constructed coal-fueled power plants were evaluated in a report for ACCCE.[4] Cichanowicz and Hein obtained CO_2 emissions data for all coal-fueled units that have commenced operation since 2007. The authors then used an EPA methodology to analyze the CO_2 emissions data to determine emissions rates that would be achievable over a ten-year period. They found the following emissions rates are achievable for new coal-fueled power plants without CCS:

- 1,915 lbs CO_2/MWh for supercritical boilers burning bituminous and subbituminous coals;
- 2,080 lbs CO_2/MWh for subcritical boilers burning bituminous and subbituminous coals; and
- 2,150 lbs CO_2/MWh for all boilers burning lignite coals.

In lieu of the performance standards in the proposed rule, EPA should adopt the emissions limits for the particular subcategories set forth above.

II. Current Status of CCS Research and Development

According to the Report of the Interagency Task Force on Carbon Capture and Storage (CCS Task Force Report), CCS development is intended to involve at least two generations of technology.[5] The first generation will demonstrate that CCS can be integrated at a coal-fueled power plant and operated at scale with existing CO_2 capture technologies.[6] The second generation of CCS development is expected to include advancements that significantly improve the cost and performance of CCS, resulting in availability of CCS for wide-spread commercial deployment.[7] To date, CCS has not been integrated at scale and demonstrated at a coal-fueled power plant.

A. Status of First Generation CCS

The first generation of CCS focuses primarily on current CO_2 capture technologies based on applications of existing gas separation technologies in other industries. The Department of Energy (DOE) is currently supporting five first generation CCS demonstration projects on coal-fueled power plants. The primary goal of these near-term projects is to integrate CCS at commercial scale on coal-fueled electric generating units. If successful, these projects will demonstrate "safe and reliable" CCS at commercial scale.[8] However, these projects are not intended to resolve concerns about the cost of CCS, especially at commercial scale. Even if these demonstrations are successful, capital cost estimates for first generation CCS -- $1790/kW for a new PC plant, $2199/kW for an integrated gasification combined cycle (IGCC) plant, and $1999/kW for a PC retrofit -- are too high for the existing technology to be economically viable.[9] First generation CCS has been estimated to increase electricity prices by up to 80 percent.[10]

The five CCS demonstration projects on coal-fueled power plants are described below. These projects are supported through grants funded by the 2009 stimulus bill, as well as prior year appropriations from the DOE Clean Coal Power Initiative which, as discussed below, precludes their consideration in determining CCS is adequately demonstrated. Four of these projects are new facilities and one is a retrofit. Only one, Kemper County, has started construction.

— **Kemper County.**[11] Mississippi Power Company, a subsidiary of Southern Company, is constructing a 582 MW integrated gasification combined cycle (IGCC) power plant in Kemper County, Mississippi. Southern received $270 million of DOE support through the Clean Coal Power Initiative and $133 million in tax credits to build the facility, that will use an existing acid gas separation technology, Rectisol and capture over 65 percent of the CO_2 produced. The captured CO_2 will be used in EOR operations.

— **Summit Texas Clean Energy Project (TCEP).**[12] The Summit Power Group is planning to build a 400 MW IGCC power plant in Ector County, Texas. Summit received $450 million of DOE support through the Clean Coal Power Initiative to build the IGCC, which will capture approximately 90 percent of the CO_2 from the gasifier using a Rectisol system. Approximately 21 percent of the captured CO_2 will be used to produce fertilizer. The remaining 79 percent will be used for EOR, with several companies purchasing the CO_2 from Summit.

— **NRG Parish.**[13] Located at the existing W.A. Parish Plant in Houston, Texas, NRG plans to build a 240 MW post-combustion capture project. This project will operate as a slip stream from an existing 270 MW power plant and will use the Fluor Econoamine Plus CO_2 capture technology. Having received $167 million from DOE through the Clean Coal Power Initiative, NRG originally planned a 60 MW project. The project was scaled up to 240 MW to provide enough CO_2 for significant oil production in nearby EOR opportunities. Hillcorp Energy Co. will receive the CO_2 from the Parish plant to conduct EOR operations at their West Ranch Field.

— **Hydrogen Energy California (HECA).**[14] SCS Energy plans to build a 400 MW IGCC facility in Kern County, California. Supported by a $408 million grant from the DOE Clean Coal Power Initiative, this facility will gasify a fuel mix composed of 75 percent coal and 25 percent petroleum coke, a solid fuel produced by the refining process. The project will utilize a Rectisol system to capture approximately 90 percent of the CO_2 produced. Like the Summit TCEP, HECA will use the CO_2 to support both EOR and fertilizer production.

— **FutureGen.**[15] Located in Meredosia, Illinois, the FutureGen Alliance plans to repower a 200 MW oil-fired unit at the Ameren Meredosia facility. This repowered unit will operate as a 200 MW coal-fueled oxy-combustion facility. The unit will capture CO_2 and inject it into a deep saline formation. This project received a $1 billion grant from DOE.

In addition to the five projects in the United States, one project in Canada, the Boundary Dam project is designed demonstrate first generation CCS. Like the projects in the United States, the Boundary Dam project has received significant federal support from the Canadian government and is currently delayed due to technical challenges associated with the project.[16]

The technological progress that could be achieved by these five U.S. projects, while very important, will not assure that CCS is deployable across the power industry. For instance, only one of the projects, NRG Parish, is on an existing pulverized coal unit. In addition, the three IGCC projects will use the same existing acid gas removal technology, Rectisol. Should all five of these projects go forward successfully, second generation CCS technologies will still be necessary to demonstrate CCS at scale to lower CCS cost and improve performance.[17] However, if the four projects that have not started construction are cancelled or withdrawn from the program, *only one* first-generation CCS project will exist in the U.S.

B. Status of Second Generation CCS

DOE is actively pursuing research and development (R&D) on second generation CCS technologies. Over the past eight years, DOE has spent approximately $6.9 billion on CCS technology development.[18] These efforts are focused on improving the performance of CO_2 capture units by developing new solvents, sorbents, and membranes to reduce the cost and improve the performance of CO_2 capture.[19]

Within the next 10 to 15 years, second generation CCS technologies will require the same type of demonstration projects that are ongoing for first generation CCS technologies.[20] These second generation demonstration projects are a prerequisite to commercial availability and economic viability of CCS technologies. Without second generation CCS demonstration projects, the prospects for commercially available and economically viable CCS are significantly diminished.[21]

III. EPA is incorrect in determining that carbon capture and storage has been "adequately demonstrated" on coal fueled power plants.

Section 111 of the CAA requires that performance standards for new sources be based on the "best system of emission reduction" (BSER) that EPA determines has been "adequately demonstrated." This statutory language expressly bars EPA from setting CO_2 performance standards based on emerging and unproven emission control technologies that have not yet been adequately demonstrated. As discussed below, the rulemaking record strongly supports the conclusion that the CCS technology is not "adequately demonstrated" and, as a result, EPA has incorrectly determined that CCS is BSER for coal-fueled power plants. To correct this problem, EPA has no choice but to withdraw the proposed CO_2 performance standards for coal-fueled plants.

This section begins with a brief analysis of the statutory requirements for determining BSER and then explains why EPA cannot consider CCS as an "adequately demonstrated" technology when setting CO_2 performance standards for coal-fueled power plants.

A. The statute bars EPA from setting performance standards based on emerging and unproven emission control technologies.

The plain language of section 111(a) and (b) of the CAA allows EPA to consider only those systems of emission reduction that have been "adequately demonstrated" when setting the numeric CO_2 performance standards for new power plants. Although not defined in the statute, the term "demonstrate" generally means "to prove (something) by showing examples of it; to show evidence of (something); to prove something by being an example of it."[22] The intent of the statute is clear based on the unmistakable meaning of this terminology. Congress' use of the word "demonstrated" clearly indicates that EPA may set performance standards based only on those emissions control systems for which actual examples exist and that there is real evidence or proof that those systems can work to reduce emissions at all stationary sources being regulated.

Courts have reinforced this plain meaning reading of the statute by making it clear that EPA may not set a performance standard for new sources based on untested or theoretical technologies that have never been demonstrated at a commercial scale. For example, the D.C. Circuit has interpreted an "adequately demonstrated" control system to be "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic way."[23] Similarly, the court in another relevant NSPS case stated that "EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture …."[24]

This interpretation of the statute is bolstered by the fact that the Act requires EPA to determine that the system of emission reduction "has been" adequately demonstrated. The use of the past tense in the statute suggests that EPA cannot rely upon projected future technology developments or demonstrations to support this determination. Rather, it clearly indicates that EPA may rely only on those emission reduction systems that have already been demonstrated to work.

In conclusion, the plain meaning of the CAA language, as interpreted by courts, confirms that EPA cannot set the CO_2 NSPS based on the presumed availability of a technology that has never been operated, let alone never been successfully demonstrated, at full-scale commercial applications.

B. EPA incorrectly interprets the CAA as authorizing the adoption of technology-forcing standards.

EPA cannot set performance standards based on unproven, emerging technologies. In the preamble to the proposed rule, however, EPA attempts to challenge this legal premise by providing an extensive legal justification for its decision to set the CO_2 performance standard based on CCS. The statute clearly does not give EPA unlimited authority to adopt standards that force the use of unproven technologies that do not satisfy the Act's "adequately demonstrated" mandate. This statutory requirement is explicit, unequivocal and therefore cannot be ignored by EPA. The record is clear that EPA lacks the supporting documentation that is necessary to conclude that CCS is "adequately demonstrated" at this time and therefore EPA's proposal violates the clear mandate established under section 111(b) of the Act. EPA's lengthy and complex legal justification in and of itself cannot re-write the plain language of the text of the Act.

C. CCS is an emerging and unproven technology that EPA may not consider in setting the CO_2 NSPS.

In the proposal, EPA has determined that CCS has been adequately demonstrated for controlling CO_2 emissions from coal-fueled power plants. The rulemaking record, however, does not support EPA's determination. As explained below, the rulemaking record strongly supports the conclusion that CCS technology is not "adequately demonstrated" and, as a result, the adoption of a CO_2 performance standard for new coal-fueled power plants based on CCS would be illegal under the CAA.

Furthermore, EPA's current NSPS proposal is also at odds with its initial April 2012 rulemaking proposal, which did not determine CCS to be an "adequately demonstrated" technology for controlling CO_2 emissions from power plants."[25] In the current NSPS proposal, EPA has failed to provide any explanation or justification for its decision to reverse course and now, less than two years later, conclude that CCS is adequately demonstrated for new coal-fueled power plants. A careful review of the facts clearly shows that nothing has changed in the 18 months that elapsed between April 2012 and the signing of the new proposal in September 2013. In fact, EPA has simply identified in support of its CCS determination the same CCS demonstration projects that were identified in the prior proposal. However, as discussed below, none of these projects are in operation and only two of them are currently under construction.

In addition, the Administration itself made statements in its National Climate Assessment (NCA) that rebut EPA's proposed conclusion that CCS is adequately demonstrated. The NCA notes that "CCS facilities for electric power plants are currently operating at pilot scale, and a commercial scale demonstration project is under construction." The NCA goes on to highlight the fact that "many uncertainties remain, including cost, demonstration at scale, environmental impacts, and what constitutes a safe, long-term geologic repository for sequestering carbon dioxide." And the NCA goes on to state "It is difficult to forecast success in this regard for technologies such as CCS that are still in early phases of development."[26]

1. There are no full-scale commercial applications of CCS on coal-fueled power plants in operation anywhere in the world.

There exists a compelling rulemaking record in support of the conclusion that CCS technology is not "adequately demonstrated." This record begins with EPA's own admission in the proposal that there are no coal-fueled power plants in the United States – or even in the world – that are currently operating with a full-scale commercial application of CCS. The most that EPA can do is point to a few full-scale CCS demonstration projects that are currently under development. However, none of these projects are operational and only two of them (i.e., Southern's Kemper Country Energy Facility and the SaskPower Boundary Dam CCS Project) are even under construction.[27] As a result, EPA is proposing to set a stringent CO_2 performance standard which no new coal-fueled plant anywhere in the world has come close to meeting.

This gap in the rulemaking record is a fatal flaw in the EPA proposal. In effect, EPA is proposing to conclude that CCS is "adequately demonstrated" based on the assumption that a few planned, but unbuilt, full-scale CCS project will successfully demonstrate in the future the effectiveness and reliability of this emerging, but unproven technology. As discussed above in Section II.A, the Agency must be able to point to real-world examples where power plants are commercially operating with CCS and the technology has in the past been demonstrated or proven to work. EPA's failure to do so means that the Agency is impermissibly proposing to set a CO_2 performance standard based on "mere speculation or conjecture" as to effectiveness and reliability of CCS in controlling CO_2 emissions from full-scale coal-fueled power plants.

2. EPA cannot base its BSER determination on small experimental projects that seek to demonstrate CCS at pilot scale.

EPA cannot correct this major gap in the rulemaking record by referencing several small pilot-scale CCS projects at power plants.

Two of the pilot-scale CCS projects referenced in the EPA proposal are a 10-MW project at the Vattenfall plant in Germany and a 25-MW project at Southern Company's Plant Barry.[28] By EPA's own account, these two projects are the only examples in the world where CCS is currently in operation at power plants. Both of these projects involve the small-scale experimental application of a CCS technology on only a small portion of the total flue gas stream from the power plant (a "slipstream"). As a result, these slipstream projects are not fully integrated with the operation of the plant and only capture and store a relatively small amount of CO_2 emissions.

A third example cited by EPA is an experimental project that American Electric Power (AEP) sponsored to validate a CCS technology at its Mountaineer Power Plant. In this case, the AEP project treated a 20-MW portion of flue gas from the 1,300-MW Mountaineer Plant that resulted in the capture and storage of almost 40,000 tons of CO_2 emissions from 2009 to 2011.[29]

By contrast, the full-scale application of CCS on a typical 500-MW coal-fueled power plant at the CO_2 capture level required to meet the proposed standard would capture more than one million tons of CO_2 per year. AEP had planned to undertake a second phase of the Mountaineer project, which would have sought to demonstrate the CCS technology at a 235-MW commercial scale, but the project was deferred due to lack of funding.[30] According to AEP, even if the Mountaineer Project had not been deferred, "the CCS technology, like other first-of-a-kind projects, would have been installed without any commercial guarantees from vendors and would have run the risk of not continuously or reliably achieving high CO_2 capture levels."[31]

These pilot-scale slipstream projects have proven that CCS is a potentially viable technology for controlling CO_2 emissions from coal-fueled power plants. However, completion of these projects is only the critical first step in demonstrating CCS on a commercial scale for capturing and permanently storing CO_2 from an operating power plant at an affordable cost. Further work is necessary to demonstrate the effectiveness, reliability, and affordability of CCS in full-scale utility applications for a variety of power plants under real-world operating scenarios. Specifically, experience with integrating CCS with the daily and around-the-clock demands of the power grid is essential to demonstrating CCS. Until this additional work is successfully completed, there is simply insufficient data and experience for EPA to determine CCS is "adequately demonstrated." The limited experience with CCS in these few pilot projects is insufficient to demonstrate that CCS can now be successfully implemented at full-scale utility applications in a manner, as the D.C. Circuit has stated, that is "reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interest of pollution control without becoming exorbitantly costly in an economic or environmental way."[32]

3. EPA cannot base its BSER determination on a few industrial applications of CCS.

EPA also claims that CCS is adequately demonstrated based on a few industrial applications of CCS. None of the referenced industrial projects involve the full-scale commercial application of a CCS technology on a power plant that sells electricity into the grid and therefore cannot constitute an "adequately demonstrated" technology that can be used to set performance standards for coal-fueled power plants under section 111(b) of the CAA.

For example, one of the industrial CCS projects cited in the EPA proposal is an industrial gasification facility located in North Dakota. This gasification facility differs substantially from a coal-fueled power plant. It was built to produce synthetic natural gas from coal, as well as fertilizers, solvents, phenol, CO_2, and other chemicals for sale.[33] As a result, the North Dakota plant does not integrate CCS technology into a power generation facility that is built for the purpose of generating reliable and affordable electricity for sale into the power grid. For EPA to suggest that capture technology used for the gasification plant should be readily transferable to coal-fueled power plants ignores the multitude of technical, process design, and operational differences between the two very different commercial applications. For example, a power plant must operate when called upon regardless of the availability of CO_2 capture equipment or a CO_2 pipeline.

Important differences also exist with respect to three other projects referenced by EPA in which CO_2 is being captured for industrial uses.[34]

Most importantly, all of these other CCS projects are capturing relatively small amounts of CO_2 emissions as compared to the CO_2 capture levels that a new coal-fueled power plant would have to achieve in order to comply with the proposed NSPS.[35] In other words, for coal-fueled power plants, the quantities of CO_2 captured will be orders of magnitude greater than for these gas streams and the end use for the captured CO_2 will be for geologic storage or EOR processes rather than food production or other industrial processes. Finally, a coal-fueled power plant with CCS must continue to operate in accordance with the demands of the electric grid. As a result, these projects do not demonstrate CCS technologies that can capture CO_2 emissions at the high-volumes and in the integrated power plant situations that are contemplated by the proposed rule.

Accordingly, EPA reaches the wrong conclusion – namely that these projects demonstrate the technical feasibility of capturing CO_2 at the large volumes and 24/7 operating conditions required for full-scale coal-fueled power plant. Accordingly, these industrial applications of CCS are clearly insufficient to support any determination that CCS can now be fully integrated and achieve sufficient CO_2 control levels at a full-scale power generation facility in a reliable, efficient and cost-effective manner.

4. EPA is barred from making BSER determination based on CCS projects that have received certain federal governmental funding.

The Energy Policy Act of 2005 (EPAct05) expressly prohibits EPA from setting performance standards for new stationary sources under section 111(d) of the CAA based on technology used or emission reductions achieved by federally funded demonstration projects that have received federal assistance under either section 402 or section 1307 of EPAct05.[36]

In violation of this prohibition, the NSPS proposal expressly relies on technologies and emission reductions achieved or projected to be achieved by facilities that have received federal assistance under these sections of EPAct05. For example, three of the five full-scale commercial

CCS projects currently under development have all received advanced coal investment tax credits under section 48A of the Internal Revenue Code, established by EPAct.[37] These CCS demonstration projects are the Kemper County Energy Facility (Kemper) Project, Hydrogen Energy California (HECA) Project, and the Texas Clean Energy Project (TCEP). Likewise, many of the smaller pilot-scale CCS projects cited by EPA in the NSPS proposal have received federal assistance under the Clean Coal Power Initiative, a DOE program that is authorized under section 402 of EPAct05. Examples of these other projects include CCS demonstration projects undertaken at AEP's Mountaineer Plant, Southern Company's Plant Barry, NRG's W.A. Parish Plant, and the Coffeyville Gasification Plant.[38]

By law, EPA may not base its determination that CCS is demonstrated on the emission limits achieved or technology used by these governmentally-funded facilities. When these CCS demonstration projects are properly excluded from the rulemaking record, it will become even more clear that EPA's determination that CCS is adequately demonstrated is flawed.

a. Section 48A of the Internal Revenue Code bars EPA from considering three full-scale commercial CCS projects that are currently under development.

Three of the full-scale commercial projects on which EPA relies in the proposed rule – the Kemper, HECA, and TCEP projects – have qualified to receive investment tax credits under section 48A of the Internal Revenue Code.[39] As a result, each of these CCS demonstration projects is subject to the following prohibition:

> 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 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. 26 U.S.C. 48A(g).

This statutory provision clearly and unambiguously prohibits EPA from "considering" the following three categories of evidence from a covered demonstration project to "indicate" that a "technology or performance level is . . . adequately demonstrated" under section 111 of the Clean Air Act:

— "use of technology … by or at one or more facilities with respect to which a credit is allowed;"

— "a level of emission reduction solely by reason of the use of the technology … by or at one or more facilities with respect to which a credit is allowed;" and

— "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."

The first and third prohibitions clearly bar EPA from considering CCS demonstration projects that receive section 48A tax credits, including the Kemper, HECA, and TCEP projects. First, section 48A(g) prohibits EPA from considering the "achievement of *any* emission reduction by the demonstration of *any* technology or performance level … by or at" a facility for which a credit is allowed (emphasis added). Under this provision, information about any emission reductions achieved through the demonstration of any technology or performance level at a relevant facility may not be "considered" by EPA – regardless of whether EPA has in its possession other data or information that could support a finding that the technology or level of emission reduction is adequately demonstrated. Second, 48A prohibits EPA from considering the "use of technology … by or at one or more facilities with respect to which a credit is allowed."

By contrast, the use of the word "solely" in the second prohibition above could arguably permit EPA to take into consideration a level of emission reduction that was not achieved "solely by reason of the use of the technology." However, the use of the term "solely" in this phrase does not limit or otherwise apply to the two other prohibitions contained in section 48A(g). This is clearly evidenced by the fact that the term "solely" is placed within parentheses, indicating that the word is meant to modify only the phrase "level of emission reduction," and not the two other statutory prohibitions discussed here.

Unlike the other provisions in the EPAct05,[40] and contrary to the interpretation that EPA asserts in its technical support document (TSD),[41] these two prohibitions in section 48A are not qualified by the term "solely" and, as a result, are not subject to any constraint that may be imposed by this term.

b. <u>Section 402 of EPAct05 bars EPA from considering clean coal demonstration projects that have received federal funding under the Clean Coal Power Initiative.</u>

The goals of the Clean Coal Power Initiative (CCPI) are to "advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated . . . ."[42] The CCPI provides direct financial support through cost-sharing arrangements for the demonstration of clean coal projects that meet specified performance criteria.[43] Notably, EPAct05 Section 402(i) places the following limitation on EPA's authority to regulate stationary sources under section 111 of the CAA:

> No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be … adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411) . . . .[44]

The most reasonable reading of section 402(i) is that EPA is required to have sufficient evidence from non-subsidized facilities to make a plausible or prima facie case that CCS is demonstrated before relying on information from facilities that have received federal assistance. As used in section 402(i), the term "solely" limits EPA's discretion to consider technologies or levels of emission reduction at subsidized facilities to only those situations where there is strong, independent evidence, including at least one non-subsidized full-scale electric utility project, which demonstrates that the technology or level of emission reduction is "adequately demonstrated."

The legislative history makes clear that Congress added the section 402(i) limitation out of concern over how EPA would use information from federally subsidized demonstration projects. Congress' specific concern was that EPA might conclude that a technology or emission reduction level was "adequately demonstrated" just because ("solely by reason of" the fact that) the technology or emission reduction was achieved at a project that was funded through an EPAct05 program. The purpose of section 402(i) is to prevent EPA from concluding that a technology is adequately demonstrated just because it was demonstrated at a facility that received significant federal funding, while allowing the Agency to designate such technologies or emission levels as adequately demonstrated once they have been adequately demonstrated elsewhere, at facilities that did not receive assistance.[45]

In light of this clear congressional intent, the most reasonable interpretation of this prohibition is that, for purposes of section 111, EPA must have sufficient evidence from facilities, including at least one full-scale electric utility application, that have not received assistance under the Act before it can rely on advanced clean coal projects that have received federal assistance under these EPAct05-authorized programs. Information from facilities that have received assistance can add weight to EPA's finding that a particular technology or emission level is adequately demonstrated, but it may not form the underlying basis for identifying that technology or emission level in the first place.

To the extent that EPA has determined that CCS is "adequately demonstrated" based primarily on information obtained from facilities receiving assistance under the EPAct05, this determination would violate section 402(i).[46] Rather, under EPAct05 section 402(i), EPA should only rely on information from these facilities as support for the NSPS if it can independently conclude (based on information from facilities that have not received federal assistance) that the technologies used at the subsidized facilities are adequately demonstrated. As demonstrated above, such a case clearly cannot be made.

5. <u>Conclusion</u>: The rulemaking record clearly indicates that CCS is not adequately demonstrated.

For all the reasons discussed above, the projects referenced in the proposal do not show that CCS is either "reasonably reliable" or "reasonably efficient."[47] Moreover, EPA is prohibited by law from relying solely on most of the examples cited in the EPA proposal as evidence that CCS is adequately demonstrated. Furthermore, because not a single power plant has successfully implemented CCS at full utility scale, data on the efficiency and reliability of CCS for full-scale applications on power plants are unavailable. In such a situation, EPA may not simply speculate or presume that CCS is adequately demonstrated for such full-scale utility applications.[48] Rather, EPA must determine the applicable NSPS based on systems of emission reduction that have been shown to be workable and cost-effective at the scale and in the industrial and regulatory context in which coal-fueled power plants operate.

D. EPA's determination that CCS is adequately demonstrated conflicts with recent BACT determinations.

EPA's proposed standard is entirely inconsistent with the determinations as to what constitutes "best available control technology" (BACT) for limiting CO_2 emissions from new facilities under the Prevention of Significant Deterioration (PSD) program. Over the last few years, both EPA and state permitting authorities have determined on many occasions that CCS is neither demonstrated at a utility scale nor a cost-effective commercially available technology when setting a CO_2 BACT limitation for new coal-fueled power plants. The list of plants for which CCS has been rejected as BACT is long and includes:

— the Taylorville Energy Center in Illinois,
— Cricket Valley Energy Center in Texas,
— Lower Colorado River Authority Generating Plant in Texas,
— MidAmerican Power Plant in Iowa,
— We Energies Power Plant in Wisconsin, and
— Russell City Energy Center in California.[49]

A similar record exists for the non-electric generation projects that have received CO_2 BACT permit limits, including cement and steel manufacturing facilities.[50]

Furthermore, EPA itself has acknowledged that additional work is needed before CCS can be integrated at full-scale electric utility applications. Most notably, the Agency states in its recent greenhouse gas BACT guidance that "while CCS is a promising technology," it is not "a technically feasible BACT option" due to the many technical challenges of integrating "the CCS components with the base facility and site-specific considerations."[51]

These CO_2 BACT determinations, along with EPA's own technical assessments, provide further support that CCS is not adequately demonstrated and therefore should not be used as the control technology for setting the CO_2 NSPS limits for new coal-fueled plants.

This conclusion is underscored by the fact the CAA stipulates that the NSPS must serve as the floor in setting the BACT limits for these new sources.[52] In effect, the NSPS sets minimum emissions control levels for new sources, while the permitting authority can increase the stringency of the emissions control requirement beyond the NSPS levels on a source-by-source basis through the rigorous BACT-standard-setting process. It makes little sense for EPA to set a more stringent CO_2 control level under the less-rigorous NSPS standard-setting process than what EPA and state permitting authorities have recently set on a source-by-source basis through the prescriptive BACT standard-setting process.

E. Neither the transportation nor storage elements of CCS are adequately demonstrated.

EPA has the burden of demonstrating that all elements of CCS – capture, transportation, and storage of CO_2 – have been adequately demonstrated at utility scale and ready for commercial deployment. This means it is not sufficient for EPA to determine that technology has been adequately demonstrated for only capturing the CO_2 emissions from coal-fueled power plants. In addition, EPA must demonstrate that the transportation and storage components of CCS are commercially viable at a utility scale. Significant hurdles must be addressed before EPA can make such an affirmative determination for both of these CCS components.[53]

In the case of CO_2 transportation, there are many legal and regulatory issues that must be resolved to support the significant build out of the existing CO_2 pipeline system that has been developed for EOR that would be needed to accommodate CO_2 from full-scale power plants. One key issue relates to the cumbersome process that would be required for the siting, land acquisition, and construction of a greatly expanded pipeline system. Another issue relates to the long lead times and large capital investments that will be necessary to build this new pipeline system. EPA has provided no explanation in proposed rule as to how these issues will be addressed.

Similarly, the storage component of CCS is in the early stages of development and clearly does not satisfy the "adequately demonstrated" requirement. This is reflected by the fact that there are no large-scale geologic storage projects integrated with power plants on a utility scale. In addition, there are many unanswered questions on the long-term storage component of CCS, which is in the early phase of development. As further discussed in Section V below, one key unanswered question relates to long-term liability of the CO_2 emissions stored in underground geological formations. These concerns regarding whether the storage component of CCS is adequately demonstrated were recently raised by EPA's own Science Advisory Board, which stated that "(t)he scientific and technical basis for carbon storage provisions is new science and the rulemaking would benefit from additional review."[54]

These important regulatory and technical issues must be addressed before EPA can determine that CCS is adequately demonstrated for purposes of the NSPS rulemaking. Further discussion of these challenges is found in Section V below.

F. CCS is exorbitantly costly and may not be economically viable even with large governmental subsidies and revenue from EOR.

EPA is required to consider costs in the NSPS standard-setting process for new sources under section 111(b) of the CAA. The preamble to the proposed rule recognizes this obligation and provides the following brief summation of cost standard that applies to the NSPS standard-setting process:

> We believe that these various formulations of the cost standard – "exorbitant," "greater than the industry could bear and survive," "excessive," and "unreasonable" – are synonymous; the D.C. Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonableness as the standard, so that a control technology may be considered the "best system of emission reduction ... adequately demonstrated" if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[55]

Under the Agency's formulation of the cost issue, the key question is whether the costs of CCS are "reasonable" or "unreasonable." One clear indicator that the CCS costs are unreasonable is the fact that no company can afford to build a new coal-fueled power plant with CCS without substantial government subsidies to overcome the very significant capital and operational costs attributable to CCS. EPA has specifically recognized the critical importance of government funding in the proposed rule.[56] Only the combination of government and private sector funding results in a cost that, according to EPA, is not exorbitant. However, even when qualifying for government funding, many of the CCS projects have either been cancelled or are struggling to be developed and may never be built due to financial challenges or major cost overruns. Given that little or no additional governmental funding is expected to support CCS projects in the future, EPA is effectively proposing to establish a CO_2 performance standard that no company can afford to meet and imposing costs that greater than utilities and their customers can bear. The imposition of such extreme costs is contrary to the requirements of the CAA, as interpreted by the courts.[57]

In the NSPS proposal, EPA attempts to argue that the exorbitantly high costs to CCS deployment can be sufficiently offset by the potential economic gains from EOR.[58] This claim is not true. Even in EPA's very optimistic cost analysis, the expected EOR revenues from the sale of the CO_2 only range from $20 to $40 per ton of CO_2. By contrast, the incremental costs of CCS could range from $60 to $100 per ton of CO_2 captured.[59] This cost comparison demonstrates that EOR revenues simply cannot bridge the increased costs that would be incurred from the CCS requirement.

Furthermore, EPA's assumptions on the potential revenue stream generated from the sale of CO_2 emissions to EOR operators are overstated for several reasons.[60] First, the potential economic gains from the EOR revenue stream will be limited to those new plants that are able to locate near an EOR site or an existing CO_2 pipeline that serves an EOR site or within a short enough distance for new pipelines to be built. This means that the opportunity to secure EOR revenues would be unavailable for many new CCS projects. Second, recent reports indicate that EOR operators could be unwilling to purchase CO_2 from new coal-fueled power plants with CCS given that the EOR operator will be required to comply with the onerous monitoring and reporting requirements imposed under Subpart RR of the GHG reporting rules.[61] In effect, the imposition of the Subpart RR requirements could effectively foreclose the use of captured CO_2 emissions for EOR operations. Even assuming that an EOR operator can be persuaded to take the captured CO_2 emissions, the price paid by the EOR operator would most likely be greatly reduced in order to offset the high Subpart RR compliance costs. Either way, however, EPA's optimistic forecasts of EOR revenues accruing to CCS developers will be greatly diminished, if not eliminated entirely.

For these reasons, the costs of CCS would be so excessive that they would preclude new coal-fueled power plants from being developed in the future. Imposing such unreasonable costs is contrary to the Clean Air Act, as interpreted by the courts. EPA has a duty not only to consider costs, but also to set a performance standard under section 111(b) that is not cost prohibitive for new coal-fueled power plants.[62]

IV. EPA incorrectly assessed the cost of CCS in the proposed NSPS

In the proposed NSPS, EPA incorrectly assessed the cost of CCS for two key reasons that contributed to EPA's conclusion that the costs of CCS are "not unreasonable." First EPA ignores the significant limitations of existing CCS cost estimates. Second EPA incorrectly ignored the input of interagency commenters regarding the characterization of CCS costs.

A. EPA ignores the limitations of the CCS cost estimates which provide the basis for their analysis

CCS cost estimates contain significant uncertainty. A number of plant specific and injection site-specific criteria will ultimately determine the cost, and cannot be considered in every cost estimate. Accordingly, EPA's analysis of the cost of CCS should more explicitly address the uncertainty associated with CCS cost estimates.

The National Energy Technology Laboratory, NETL, the author of CCS cost estimates used by EPA, specifically acknowledges the uncertainty in their estimates. NETL notes that the cost estimates in their study have a significant band of uncertainty, noting that cost "estimates in this study have an expected accuracy range of -15%/+30%."[63] NETL goes on to note that the value of their cost estimates "lies not in the absolute accuracy of cost estimates," explaining that the common methodology and assumptions made the cost estimates useful in comparing to other costs within the same report.[64] Nonetheless, EPA uses NETL CCS cost estimates in the precise manner which NETL expressly advised against – as absolute measures of the cost of CCS.

Beyond the uncertainty referenced by NETL, EPA inappropriately uses the NETL cost estimates because of the optimistic storage assumptions used in the NETL analysis. As discussed in Section V, EPA has ignored the technical challenges associated with CO_2 storage in this proposal. Similarly, NETL, in their analysis of CCS costs upon which EPA relies, notes that the cost estimates for CO_2 storage are for a "favorable" storage site.[65] NETL admits that any individual project cost may vary "significantly" based on a number of site specific factors, such as those discussed in Section V.[66] The substantial uncertainty and potential for significant variations in CO_2 storage costs limit the usefulness of this NETL study in evaluating the cost basis for CCS in this NSPS.

B. EPA incorrectly ignored the input of interagency commenters regarding the characterization of CCS costs as "next-of-a-kind"

During the interagency review process, interagency commenters noted that EPA inappropriately relied on lower NETL CCS cost estimates based on a next-of-a-kind (NOAK) plant. Interagency commenters suggested that EPA use the higher first-of-a-kind (FOAK) cost NETL estimates.[67] If EPA is going to use the NETL cost estimates despite the limitations as discussed above, EPA should follow these comments and use FOAK cost estimates. The reason that NOAK cost estimates are lower than FOAK cost estimates is based on the gradual reduction in costs that occurs as new technology is successfully operated at scale. This "learning" occurs as projects come online and begin to operate. Given that no large scale CCS project at a coal fired power plant has come on line to date and only two are under construction, higher FOAK cost estimates are warranted in the proposed NSPS. Illustrative of the limited amount of learning about integrating CCS at full scale at coal-fueled power plants that has occurred, the Kemper project, the only CCS project under construction in the United States, is an IGCC plant using a unique gasifier technology burning lignite coal. These characteristics limit the learning available from this plant to, for example, a supercritical boiler burning bituminous or subbituminous coal or even an IGCC unit using different gasification technology fueled with these other coals. EPA should recognize the limited opportunities for learning to date and use higher FOAK cost estimates while appropriately noting the uncertainty and limitations of those estimates.

V. EPA ignores the technical and permitting challenges of CO_2 storage and therefore fails to assess fully the costs of CCS

Full scale application of CCS on a power plant requires that CO_2 transportation and long-term subsurface storage is available at all times. Air pollution control technology for conventional air pollutants can produce byproducts that are collected and can be stored in storage ponds and landfills on- or off-site. Unlike conventional air pollution control byproducts, the significant quantities of CO_2 removed from an emissions stream by CO_2 capture equipment are in a gaseous form and cannot be stored onsite; the CO_2 must be transported for long-term storage.

As briefly discussed above in Section III.D, EPA has not adequately examined the feasibility and challenges of CO_2 storage in the proposed NSPS. CO_2 storage primarily occurs in two geologic settings: EOR and saline storage. Both settings pose major technical challenges to commercial CCS operations that are not considered by EPA. In its discussion of CO_2 storage, EPA presents some evidence intended to support the notion that CO_2 storage is available and that it does not pose a barrier to CCS project development. In fact, EPA failed to consider several aspects of CO_2 storage that limit the feasibility of utilizing CCS at a coal-fueled power plant.

A. EPA ignores current challenges to integrating CO_2 capture from a coal-fueled power plant with CO_2 EOR

In discussing EOR, EPA notes the potential role EOR may play in the future if coupled with captured CO_2 from a variety of stationary sources. While this potential exists, current EOR operators and CO_2 emitters face a significant number of challenges in realizing the benefits of these opportunities. These challenges are not addressed by EPA. The extent to which a new coal-fueled power plant can sell their CO_2 to an EOR operator is limited by a number of factors. The most critical limiting factor is the availability of CO_2 pipelines. The approximately 3600 miles of CO_2 pipeline in the United States are constrained to those regions in which CO_2 EOR has been ongoing for many years.[68] Absent significant pipeline infrastructure increases, CO_2-EOR will likely remain only a regional option for CO_2 storage.

In addition to the infrastructure limitations, recent actions by EPA may limit the ability of CO_2 EOR to serve as a CO_2 storage option even in the limited regional settings where the infrastructure may be adequate. Beyond the additional monitoring required by this NSPS, discussed above, in December 2013, EPA published their "Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells" (Transition Guidance).[69] This Transition Guidance covers those instances in which CO_2 EOR operations, generally permitted as a UIC Class II well by a state agency, will have to convert to a UIC Class VI permit (a new class of UIC well permit developed and issued by EPA, or authorized state agency, for geologic storage of CO_2). This guidance provides a series of criteria to be evaluated by the permitting authorities in determining if and when an EOR operation must transition to Class VI. This guidance document creates tremendous uncertainty for CO_2 EOR operators that intend to accept CO_2 captured from anthropogenic sources like coal-fueled power plants. Specifically, the transition guidance does not allow an EOR operator using anthropogenic CO_2 to know the operational circumstances under which the operator would be required to transition from Class II to Class VI. This uncertainty will limit the role of CO_2 EOR in near term CCS deployment, and may eliminate it altogether. Exacerbating the uncertainty is the significant additional costs that would result from converting from Class II to Class VI due enhanced construction and monitoring requirements. ACCCE, along with other trade associations, submitted comments to this effect to EPA, incorporated herein and attached as Appendix 3.

B. EPA ignores major unresolved challenges with saline storage of CO_2

Operating CO_2 storage facilities in saline formations faces two types of significant challenges not addressed by EPA in this rulemaking. First, the existing regulations for CO_2 injections in saline formations, permitted as Class VI injection wells under EPA's UIC program, pose practical barriers to project development. Second, the long-term liability framework for injected CO_2 remains uncertain in many areas of the country and limits the opportunity to store CO_2 in saline formations in those regions.

EPA's Class VI well regulations, finalized in 2010, establish a rigorous regulatory scheme for the injection of CO_2 in the subsurface. One element of the regulatory scheme in particular, a post-injection site care monitoring period of 50 years, poses particular challenges in project development. A typical injection from a power plant may last several decades. Adding 50 years of post-injection site care has the potential to exceed the lifetime of organizations involved in the original injection program, adding contractual and legal challenges to the development of a CO_2 injection operation. In addition to these challenges, only one draft permit such an injection process integrated at a coal-fueled power plant has been issued by the U.S. EPA, and no state has been granted authority to grant Class VI permits by EPA.[70] This lack of permitting experience by the regulators and the regulated community will exacerbate the uncertainty that remains in the regulatory framework.

Finally, there are a significant number of challenges outside UIC injection regulations themselves which may pose challenges for a CO_2 injection project that have not been adequately considered by EPA. Once CO_2 has been injected, the legal framework for managing the potential liability resulting from the injected CO_2 remains uncertain. In 2010, the CCS TF report identified long-term liability as a key barrier to CCS deployment according to stakeholders.[71] Currently, a patchwork of state policies exists, leaving the uncertainty that surrounds long-term liability for injected CO_2 unresolved.[72]

While the considerations discussed above will vary site by site, and project by project, they impact the feasibility of integrating CCS at a power plant. These challenges must be sorted out *prior to* the beginning of CCS operations because subsurface storage must be operational at all times for a CCS project. EPA must reconsider the challenges of CO_2 storage outlined here because they pose direct challenges to the feasibility of integrating CCS at a coal-fueled power plant.

VI. EPA is incorrect in asserting that the CAA is technology forcing, and the proposed NSPS in fact slows CCS technology development.

EPA asserts that the CAA authorizes the adoption of technology-forcing standards and that the NSPS will incentivize or spur CCS development in the United States. EPA is incorrect on both accounts. As discussed above, the language of the CAA allows for no such interpretation. Beyond the statutory limitation, the proposed NSPS will inhibit continued CCS development in the United States.

A. Contrary to EPA assertions, the NSPS proposal will slow CCS development in the United States

By mandating CCS on all new coal-fueled power plants before the technology is commercially available, EPA will create a major barrier to the development and deployment of CCS in the United States. Advanced CCS technology, still in early stages of research and development, will require demonstration in order to become commercially available. This demonstration needs to occur at new coal-fueled power plants, but this rule will prevent any new coal-fueled power plants from being built. Without demonstration projects, advanced CCS technology may likely never become commercially available in the United States.

The Administration's CCS Task Force Report divided CCS technology into first and second generation.[73] First-generation CCS technology that is being demonstrated today is primarily adapted from existing technology applied in other industrial sectors. These projects will demonstrate that CCS can be integrated at scale at a coal-fueled power plant and operate safely and reliably.[74] Second-generation CCS promises to drive down costs and improve performance, with the intention of making CCS on a coal-fueled power plant more competitive.[75] Second-generation CCS technologies are currently in the early stages of development, and may be several years away from demonstration.[76]

New coal-fueled power plants play a critical role in demonstrating CCS technology. As discussed above, U.S. DOE is currently supporting five demonstration projects on coal-fueled power plant. Of these five, only one is applying CCS to a conventional pulverized coal plant.[77] These demonstration projects incorporate first generation CCS technology. Second generation CCS technology will need to be demonstrated as R&D progresses. New power plants will have to play a similarly important role in the demonstration of second generation CCS.

New coal-fueled power plants will need to participate in second generation CCS demonstration projects for two reasons. First, second generation CCS technologies that are applicable to IGCC systems will require new power plants for demonstration. Currently, three IGCC power plants are operating in the United States and one is under construction. CCS must be designed and integrated into an IGCC power plant *a priori* because the removal of CO_2 occurs before combustion of the gasified coal. This provides no opportunities to demonstrate second generation CCS technology at the few existing IGCC power plants. Second, existing power plants face a number of site- and plant-specific limitations to participating in a CCS demonstration project. These limitations include: available surface space on site to construct and integrate a carbon capture unit, proximity to existing pipeline infrastructure to sell CO_2 into an EOR facility, suitable local storage geology if EOR is not available or cost effective, the extent of conventional air pollution control and the remaining useful life of the plant. Overcoming these challenges has limited, and will likely continue to limit, the opportunity to demonstrate second generation CCS on existing coal plants.

In preventing plans for new coal-fueled power plants, EPA is impeding, if not outright stalling, the development of CCS in the United States. For the reasons outlined above, and as evidenced by the fact that four of five current demonstration projects are integrated at new plants, new coal-fueled power plants are essential for the demonstration of second generation CCS technologies. When no new coal-fueled power plants are being built, demonstrations are very unlikely to occur. Absent demonstration, the critical technological progress necessary for the eventual widespread deployment of CCS will not occur in the United States. Stalled CCS development will hamper the ability of the United States potential to export such technology to the world.

B. This rule does not provide a path forward for CCS development

Some have claimed that the proposed NSPS provides a "path forward" for coal and for CCS development. These claims are incorrect; the exact opposite is in fact the case.

CCS R&D has been ongoing for more than a decade, long before the prospect of an NSPS which requires CCS.[78] This is not uncommon for air pollution control technology. Historically, other technologies have undergone R&D long before a regulatory requirement mandating the use of the technology existed.[79] To date, most of the CCS R&D in the United States has been supported by the DOE.[80] Two elements have been required for that R&D to be successful: Federal funding and industrial parties willing to cost share in the research. Similarly, these two elements are required to continue CCS R&D in the United States. The proposed NSPS, as discussed above in Section VI.B, and noted by others, will discourage industrial parties from cost sharing CCS R&D.[81] Contrary to the claims, this proposed NSPS does not provide a path forward for CCS development but hinders it.

Conclusion

ACCCE urges EPA to withdraw the proposal because it is profoundly flawed, biased against the future use of coal to generate electricity, and inconsistent with the President's "all-of-the-above strategy" for domestic energy. The proposal effectively bans future coal-fueled power plants because it requires such plants to use CCS, a technology that is not commercially available or economically viable for coal-fueled power plants. Banning new coal-fueled power plants is bad energy policy for our nation because it will result in an overreliance on natural gas for new base load generation – a fuel that has a long history of price volatility and deliverability challenges. Rather, EPA should adopt an NSPS that keeps coal, our nation's most abundant fossil energy resource, as a fuel option to generate electricity if it makes good economic and business sense to do so. EPA should not be picking winners and losers in energy markets.

To correct these fatal flaws in the NSPS proposal, we ask that EPA withdraw its proposal, and re-propose a CO_2 performance standard with emissions levels based on new high efficiency coal-fueled power plants without CCS. This is required by the Clean Air Act and will allow continued technology development.

Sincerely,

/s/

Paul Bailey

Senior Vice President, Federal Affairs and Policy

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[1] *See* EPA proposed rule, entitled *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 1430 (January 8, 2014).

[2] *Ibid* at 1433.

[3] *See* Wantanabe & Suga, *Post-Fukushima Japan Chooses Coal Over Renewable Energy*, (April 13, 2014) available at: http://www.bloomberg.com/news/2014-04-13/post-fukushima-japan-chooses-coal-over-renewable-energy.html (describing Japan's plan to commercialize ultrasupercritical coal technology by 2020); Qili, *The Development Strategy for Coal-Fired Power Generation in China* (June 4, 2013) (noting that China currently has 46 ultrasupercritical coal units greater than 1 GW); RealClearEnergy, *For Germany, It's Coal, Coal, Coal* (January 16, 2014) (highlighting the approximately 30 new coal-fueled power plants planned in Germany).

[4] Cichanowicz, J. Edward and Michael C. Hein, *Evaluation of CO_2 Emissions Rates from State-of-art Coal-fired Electric Generating Units (EGUs)*, February 26, 2014. This report, included as Appendix 2, is an update of an earlier report for ACCCE by the same authors, dated June 19, 2013. The authors examined early emissions data from AEP's John W. Turk plant, the one ultra-supercritical EGU operating in the U.S. Additional data are needed to develop a recommended achievable emissions rate for ultra-supercritical EGUs.

5 *Report of the Interagency Task Force on Carbon Capture and Storage*, 9 (2010).

6 *Ibid*.

7 *Ibid*.

[8] *Ibid*.

[9] Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, 6, (2013), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf; National Energy Technology Laboratory, *Assessment of Power Plants That Meet Proposed Greenhouse Gas Emissions Performance Standard*, 12 (2009).

[10] Aaron Larson, *CCS Could Increase Coal-Fired Electric Generation Costs By 70%–80%*, http://www.powermag.com/ccs-could-increase-coal-fired-electric-generation-costs-by-70-80/.

[11] MIT, *Kemper County IGCC Fact Sheet,* http://sequestration.mit. edu/tools/projects/kemper.html; National Energy Technology Laboratory, Demonstration of a Coal-Based Transport Gasifier: Project Facts, http://www.netl.doe.gov/publications/ factsheets/project/NT42391.pdf.

[12] MIT, *Texas Clean Energy Project (TCEP) Fact Sheet*, http://sequestration.mit.edu /tools/projects/tcep.html; National Energy Technology Laboratory, *Summit Texas Clean Energy, LLC: Texas Clean Energy Project: Pre-*

Combustion CO2 Capture and Sequestration; Project Facts, http://www.netl.doe.gov/publications/ factsheets/project/FE0002650.pdf.

[13] MIT, *W.A. Parish Fact Sheet*, http://sequestration.mit.edu/tools/projects/ wa_parish.html; National Energy Technology Laboratory, *NRG Energy: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project: Project Facts*, http://www.netl.doe.gov/publications/factsheets/project/FE0003311.pdf

[14] MIT, *Hydrogen Energy California Project (HECA) Fact Sheet*: http://sequestration.mit.edu/tools/projects /heca.html; National Energy Technology Laboratory, *Hydrogen Energy California Project: Project Facts*, http://www.netl.doe.gov/publications/factsheets/project/ FE0000663.pdf.

[15] MIT, *FutureGen Fact Sheet*, http://sequestration.mit.edu/tools/projects/ futuregen.html; National Energy Technology Laboratory, *FutureGen 2.0: Project Facts*, http://www.netl.doe.gov/publications/ factsheets/project/FE0001882-FE0005054.pdf.

[16] MIT, *Boundary Dam Fact Sheet,* http://sequestration.mit.edu/tools/projects/boundary_dam.htm; *SaskPower says unexpected findings have delayed carbon capture project*, February 20, 2014, http://www.thestarphoenix.com/business/SaskPower+says+unexpected+findings+have+delayed+carbon+ capture/9531810/story.html

[17] International Energy Agency, *Technology Roadmap: Carbon capture and storage*, 9 (2013);

[18] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide*, 5 (2012).

[19] *Report of the Interagency Task Force on Carbon Capture and Storage*, 87 (2010).

[20] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide*, 6 (2012).

[21] International Energy Agency, *Technology Roadmap: Carbon capture and storage*, 9 (2013).

[22] Merriam-Webster definition at http://www.merriam-webster.com/dictionary/demonstrate (emphasis added).

[23] *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphasis added).

[24] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999)(citing *National Asphalt Pavement Ass'n*, 539 F.2d at 787) (emphasis added).

[25] *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources; Electricity Generating Units; Proposed Rule,* 77 F.R. 22418 (April 13, 2012). The Agency's current proposal also conflicts with a 2010 EPA report on technologies to reduce CO_2 emissions from the electric power sector. In this report, EPA concluded that "full-scale carbon separation and capture systems have not yet been installed and fully integrated at an EGU." *See* EPA, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Based Electric Generating Units* at 26 (Oct. 2010), *available at* www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

[26] U.S. Global Change Research Program, *Third National Climate Assessment Report*, http://nca2014.globalchange.gov/system/files_force/downloads/low/NCA3_Climate_Change_Impacts_in_ the_United%20States_LowRes.pdf?download=1.

[27] *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources; Electricity Generating Units; Proposed Rule,* 79 F.R. 1475 (January 8, 2014)

[28] *Ibid.*

[29] *Written Testimony of Mark McCullough, Executive Vice President, American Electric* Power, 4 (March 5, 2013) *available at:* http://docs.house.gov/meetings/IF/IF03/20130305/100392/HHRG-113-IF03-Wstate-McCulloughM-20130305.pdf.

[30] *Ibid*.

[31] *Ibid* at 17.

[32] *Essex Chemical Corp*., 486 F.2d at 433.

[33] 79 F.R. 1475.

[34] One of the industrial CCS projects cited by EPA is the Searles Valley Minerals soda ash plant in Trona, California. The Searles Valley plant is capturing only about 270,000 metric tons of CO_2 per year, which is relatively small amount of the CO_2, as compared to total annual emissions of a typical coal-fueled power plant. [Cite.] In addition, EPA cites to AES's Warrior Run and Shady Point power plants, which also capture small amounts of CO_2 for use in the food processing industry. [Cite.]

[35] The CO_2 capture rates for these three projects are not anywhere near the same level of capture (approximately 40 percent or the proposed standard of 1,100 lbs of CO_2/MWh) that EPA claims is demonstrated and commercially available in setting the standard. [Discuss further.]

[36] Section 402 of EPAct 2005provides that "[n]o technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be … adequately demonstrated for purposes of [section 111 of the Clean Air Act]." 42 U.S.C. §15962(i). Similarly, section 1307(b) of EPAct 2005 provides that "[n]o 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 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." 26 U.S.C. §48A(g).

[37] Section 1307 of EPAct05 established an investment tax credit for eligible "clean coal facilities" and codified that tax credit at section 48A of the Internal Revenue Code (IRC), 26 U.S.C. § 48A (2012).

[38] EPAct05 section 421(a) also includes language that imposes similar prohibitions on use of information from projects funded under that section. However, because no projects have received assistance under section 421, those sections are not relevant to EPA's current rulemaking.

[39] Kemper received its certification for the investment tax credit four years ago (*see* IRS Announcement 2010-56, 2010-39 I.R.B. 398 (September 27, 2010)); HECA and TCEP received their certifications last year (*see* IRS Announcement 2013-2, 2013-2 I.R.B 271 (January 7, 2013); IRS Announcement 2013-43, 2013-46 I.R.B. 524 (Nov. 12, 2013)).

[40] In section 402(i), for example, the phrase containing the word "solely" is set off by commas from the word "level of emission reduction" and from the rest of the prohibition. *See* EPAct05 § 402(i). In section 421(a), the word "solely" comes *after* references to §§ 111, 169, and 171, and is again set off by commas. Under the usual conventions of statutory interpretation, "solely" should have independent meaning in each of these non-parallel formulations. Moreover, IRC section 48A includes a separate, *additional* prohibition on consideration of the "achievement of any emission reduction by the *demonstration* of any technology or performance level" in section 111 rulemaking. Sections 402(i) and 421(a) do not include this separate prohibition on using information from demonstrations of technology.

Thus, EPA's attempt to argue that the import of the word "solely" in the context of section 48A should be the same as in the other, differently worded provisions, is not convincing.

[41] *See* EPA, Technical Support Document, Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs, at 13 (January 8, 2014) (herein referred to as "TSD").

[42] EPAct05 § 402(a).

[43] EPAct05 §§ 402(b)(2), (d), (e). One of the key criteria for receiving assistance under the CCPI is that the project is likely "to improve the competitiveness of coal among various forms of energy in order to maintain a diversity of fuel choices in the United States to meet electricity generation requirements. . . ." EPAct05. § 402(d)(2)(B). Thus, the CCPI was clearly intended to help maintain fuel diversity and ensure that coal-fueled power plants would continue to play an important role in electricity generation by funding experimental and demonstration-stage projects that otherwise would not be built.

[43] 42 U.S.C. § 15962(i).

[44] 42 U.S.C. § 15962(i).

[45] For example, the relevant House Energy and Commerce Committee Report "specifies that the use of a certain technology by any facility assisted under this subtitle or the achievement of certain emission reduction levels by any such facility will not result in that technology or emission reduction level being considered … 'adequately demonstrated'" when setting new source performance standards under section 111 of the CAA. H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215 at 238 (July 29, 2005). H.R. 1640 is the precursor to EPAct05, and provided the blueprint for many of the clean coal programs at issue here. The Report includes a similar explanation of the prohibition contained in the Clean Air Coal Program (which became EPAct05 § 421). *Id.* at 240.

[46] Specifically, EPA's determination would violate the section 402(i) prohibition because it would "result in [technology used by facilities receiving assistance] or emission reduction level[s achieved at such facilities] being considered … 'adequately demonstrated' for purposes of section[ ]111 … of the Clean Air Act."H. Comm. Energy and Commerce, Report to Accompany H.R. 1640, the "Energy Policy Act of 2005," H.Rep. 109–215 at 238 (July 29, 2005).

[47] *See Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

[48] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999**).**

[49] See Edison Electric Institute, *Comments on Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units; Docket Nos. EPA-HQ- -OAR-2011-0660; FRL-9654-7*, at pages 68-73 (June 25, 2012).

[50] See *ibid*. at 73-74.

[51] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at page 36 (EPA-457/B-11-001) (March 2011) (stating "CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.,* space for CO2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for storage, or other storage options").

[52] *See* Section 169(3) (prohibiting the BACT limits to "exceed the emissions allowed by any applicable [NSPS] standard established pursuant to section 111").

[53] In addition, it should be noted that the EPA proposal is fatally flawed because it relies *solely* on the carbon capture component of the CCS and does not specifically require the sequestration of any CO_2 emissions from the affected power plant. *See* 79 Fed. Reg. at 1483-84. According to EPA, "compliance with the standard of 1,100 lbs CO_2/MWh is determined by the tons of CO_2 captured by the emitting EGU" and the "tons of CO_2 sequestered by the geologic sequestration are not part of that calculation." *Id*. at 1483. This means that, contrary to the statute EPA's proposed NSPS is not based on a "system of emission reduction" through on-site or off-site sequestration or storage of the CO_2 emissions. Rather, the performance stand is only based on the separation or capture of the CO_2 emissions and does not result in any enforceable emissions *reduction* requirement, as required by the plain language of the statute.

[54]*Memorandum on 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*, 3 *available at:* http://yosemite.epa.gov/sab/sabproduct.nsf/18B19D36D88DDA1685257C220067A3EE/$File/SAB+Wk+GRP+Memo+Spring+2013+Reg+Rev+131213.pdf

[55] 79 F.R. 1464

[56] 79 F.R. 1443, 1479

[57] *See e.g., Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) (stating that the inquiry is whether the costs of the performance standard are "greater than industry could bear and survive"); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973(stating that NSPS compliance costs should not become "exorbitantly costly in an economic or an environmental way").

[58] 79 F.R. 1478-9. In particular, EPA states that EOR "can significantly lower the cost of implementing CCS. … The opportunity to sell the captured CO_2 rather than paying directly for its long-term storage, greatly improves the economics of the new generating unit." Cite.

[59] *Report of the Interagency Task Force on Carbon Capture and Storage*, 34 (2010).

[60] Further discussion of these issues is provided in Section three of the ACCCE comments

[61] NSPS proposal at 279 (stating that if the captured CO_2 is injected underground, then "the facility injecting CO_2 underground must report … under subpart RR").

[62] In *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), the court remanded EPA's NSPS for Portland Cement plants so that EPA could consider whether "the standard as adopted *unduly precludes supply of cement*, including whether it is unduly preclusive as to certain qualities, areas, or low-cost supplies." *Id.* at 388 (emphasis added). The D.C. Circuit also has underscored how intertwined achievability and costs can be stating that "the statutory standard is one of achievability, given costs" and that "[s]ome aspects of 'achievability' cannot be divorced from consideration of 'costs.'" *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 431, fn. 46.

[63] National Energy Technology Laboratory, *Cost and Performance Baseline for Fossil Energy Plants,Volume: Bituminous Coal and Natural Gas to Electricity, Revision 2a*, 44 (September 2013).

[64] *Ibid.* at 45.

[65] *Ibid.* at 54.

[66] *Ibid.*

[67] *Summary of Interagency Working Comments on Draft language under EO12866 Interagency Review. Subject to Further Policy Review, EPA Response*, 1, *available at:* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0066.

[68] *Report of the Interagency Task Force on Carbon Capture and Storage*, 36, B-1 (2010).

[69] EPA, *Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells*, http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13004.pdf

[70] Only one draft Class VI permit has been issued to date, for the FutureGen project. FutureGen Alliance 2.0 Permit Application, http://www.epa.gov/region5/water/uic/futuregen/.

[71] *Report of the Interagency Task Force on Carbon Capture and Storage*, 109 (2010).

[72] *See* CCSReg Project, *State CCS Policy*, *available at*: http://www.ccsreg.org/bills.php?policy=S_LTS.

[73] *Report of the Interagency Task Force on Carbon Capture and Storage*, 89 (2010).

[74] *Id.* at 87.

[75] *Id.*

[76] U.S. Department of Energy, *2012 Technology Readiness Assessment: Carbon Capture, Utilization, and Storage (CCUS)*, 20 (2012) (indicating that the majority of CCUS technologies are at technology readiness level three or four, and requiring additional years of continued research and development

[77] *See* MIT, *Power Plant Carbon Dioxide Capture and Storage Projects,* https://sequestration.mit.edu/tools/projects/index_capture.html (detailing the CCS projects worldwide, and indicating that one project in the United States is a post combustion project, the only one which is on an existing plant).

[78] *See generally,* Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* (June 2012).

[79] *Testimony of Robert Hilton*, 7 (March 12, 2014) *available at:* http://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-WState-RHilton-20140312.pdf

[80] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide*, 5 (June 2012).

[81] *Testimony of Robert Hilton*, 12 (March 12, 2014) *available at:* http://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-WState-RHilton-20140312.pdf

Appendix 1

AMERICAN COALITION FOR CLEAN COAL ELECTRICITY

Alliance Coal, LLC

Alpha Natural Resources

AMEREN Corporation

American Electric Power

Arch Coal, Incorporated

Arkansas Electric Cooperative Corporation

Associated Electric Cooperative

Basin Electric Power Cooperative

BNSF Railway Company

Buckeye Power, Incorporated

Caterpillar Incorporated

CONSOL Energy Inc.

Crounse Corporation

CSX Corporation

DTE Energy

Joy Global Inc.

LG&E and KU Energy LLC

Murray Energy Corporation

Natural Resource Partners L.P.

Norfolk Southern Corporation

Oglethorpe Power Corporation

Patriot Coal

Peabody Energy Corporation

Prairie State Generating Company, LLC

Southern Company

Sunflower Electric Power Corporation

Tri-State Generation & Transmission Assn.

Union Pacific Railroad

Western Fuels Association

Western Fuels Colorado

May 2014

Appendix 2

EVALUATION OF CO_2 EMISSIONS RATES FROM STATE-OF-ART COAL-FIRED ELECTRIC GENERATING UNITS (EGUs)

prepared for the

American Coalition for Clean Coal Electricity

prepared by

J. Edward Cichanowicz
Saratoga, CA

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May 2014

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SECTION 1

EXECUTIVE SUMMARY

This paper, which updates an earlier analysis dated June 19, 2013, presents the results of a statistical evaluation of a comprehensive data set of CO_2 emissions that reflect state-of-art coal-fired power plants. Specifically, a total of 21 electric generating units (EGUs) were considered as reference cases, of which all but one entered commercial service on or after January 1, 2007, and commercially operated for a minimum of 18 months by December 31 of 2013.[1] The analysis of CO_2 emission rates reported in this paper employs a statistical procedure that has been used by EPA in rulemaking activities.[2] This statistical procedure is invoked in this analysis to project an emissions rate that is "achievable" for the referenced state-of-art coal-fired power stations.

The analysis includes state-of-art pulverized coal-fired units using three fuels: PRB, eastern bituminous, and lignite coal. Boilers employing supercritical and subcritical steam conditions, and circulating fluid bed (CFB) design are also included. This report summarizes but does not use data from integrated gasification/combined cycle (IG/CC) units in the analysis, as such data is either limited or does not represent state-of-art IG/CC technology.

Among other conclusions, these results show CO_2 emissions are affected by design and operating conditions that cannot in all cases be readily controlled by operators. The results in this paper suggest the importance of ambient conditions and temperature on CO_2 emissions. Specifically, four reference units of generally similar design and cooling systems exhibit a difference in CO_2 emission rates that could be influenced by the annual average of the ambient temperature of heat rejection. Further, data for most plants showed that CO_2 emissions are significantly influenced by load factor – operating at less than 80% of maximum load generates CO_2 emissions that can be higher by 100-200 lbs CO_2/MWh, compared to maximum load.

This approach suggests that the following CO_2 emission rates (on a calendar-year, annual average basis) should be considered reasonably "achievable" for the three subcategories of coal-fired EGUs:

- 1,915 lbs CO_2/MWh for supercritical boilers burning bituminous and subbituminous coals;

[1] In addition to the twenty units that entered commercial service after January 1, 2007, Zimmer Unit 1 was included as it was selected by EPA as a supercritical bituminous coal-fired reference unit.
[2] EPA Report EPA-453/R-94-012, "New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard", June 1997.

- 2,080 lbs CO_2/MWh for subcritical boilers burning bituminous and subbituminous coals; and
- 2,150 lbs CO_2/MWh for all boiler types burning lignite coal.

These projected emission rates, while now including full-year 2013 data, are essentially unchanged from the June 2013 analysis.

Finally, CO_2 emission rates were calculated using both a 12-month calendar year "block" average and a 12-month rolling average. The 12-month rolling average is calculated from 30-day averages, and updated by adding the latest and deleting the oldest data. The example cases considered operation after commissioning and startup operations were complete, and thus represent well-controlled commercial operation. The results of this analysis show no significant difference could be discerned using these two averaging methods. However, it is possible under some conditions there could be a difference in "block" and 12-month rolling CO_2 averages. The operating conditions that would prompt such a difference would be for less than 12 months of operation, such as during commissioning and start-up, or after an extended maintenance outage.

SECTION 2

INTRODUCTION

This report describes the factors that affect CO_2 emissions from state-of-art coal-fired electric generating units (EGUs) and shows such emissions vary widely, consistently exceeding 1,800 lbs/MWh. These data show CO_2 emissions are affected by a wide variety of factors, such as fuel choice, unit operating conditions, and site features including cooling methods.

Annual CO_2 emission rates were calculated using data from several sources. All process and emissions data used in this analysis were taken from EPA's Air Markets Program Data (AMPD).[3] Descriptions of cooling systems and fuel quality, specifically the heat content of coal, were extracted from the DOE Energy Information Administration (EIA) Form-923/860.[4] The annual CO_2 emissions rate is expressed as tons of CO_2 emitted (converted to pounds) divided by gross load (in MWh), as reported in the AMPD. All units examined are single-boiler generators; thus, no aggregation or weighting is needed to present boiler-level and EGU-level data.

Section 3 of this report describes factors affecting CO_2 emissions from coal-fired power stations. Section 4 discusses the additional reference units selected for this analysis, and how they were chosen. Section 5 presents the CO_2 emissions data derived from both the EPA reference and the additional sources. Section 6 reviews and evaluates the reported CO_2 emissions data, and Section 7 employs a statistical analysis – used by EPA in prior rulemaking activities – to project NSPS limits consistent with these data.

[3] http://ampd.epa.gov/ampd/QueryToolie.html and ftp://ftp.epa.gov/dmdnload/emissions/.
[4] http://www.eia.gov/cneaf/electricity/page/data.html.

SECTION 3

FACTORS AFFECTING CO_2 EMISSIONS FROM COAL-FIRED EGUs

The CO_2 emission rate from coal-fired power plants depends on a variety of station design and operating factors. For coal of the same composition, the CO_2 emitted per unit of power output depends on the thermal efficiency of the power generation. In addition, the composition of the source coal – specifically, the relative amounts of carbon, hydrogen and moisture – are important.

GENERATING UNIT DESIGN

Figure 3-1 depicts how boiler thermal efficiency and the temperature of both heat addition and rejection affect the thermal performance of a power plant, when viewed as a simple "heat engine".

Figure 3-1 shows in the "Boiler Efficiency" box that heat content in the fuel is directed to either raise steam or lost to the stack through both "latent" heat to evaporate the moisture in the coal or "sensible" heat in product gases. Coals with higher free moisture content, such as subbituminous coals (particularly those from the Powder River Basin), can contain more than 30% moisture. High moisture coals allow more heat to "leak" past the steam generator as latent heat and escape to the stack, without contributing to raising steam.

The thermal efficiency of the entire generating unit depends on both the boiler efficiency, as previously described, and the thermal efficiency of the steam cycle. Figure 3-1 recognizes that all steam is not created equal, as some steam conditions – those with higher pressure and temperature – contain more energy that can be converted to work (i.e., MWh). Steam conditions can be distinguished by the pressure and temperature relative to the "critical" state, where steam behaves not like a mixture of water and gas but a fluid. As shown in the "Heat Addition Temperature" box in Figure 3-1, steam of different "states" can be used. Using steam of "subcritical" state (2,400 psig and 1,000°F) will typically generate power at approximately 36%. In contrast, using steam of the "supercritical" state (3,208 psig, 1,000-1,050°F) can elevate the thermal efficiency of power generation by as much as three to six percentage points[5] (e.g., 36% subcritical thermal efficiency can be increased to 39%, or possibly to 45%).

[5] Power Magazine, "MidAmerican's Walter Scott Jr. Energy Center Earns Power's Highest Honor", August 15, 2007. Available at: http://www.powermag.com/coal/MidAmericans-Walter-Scott-Jr-Energy-Center-Unit-4-earns-POWERs-highest-honor_210.html.

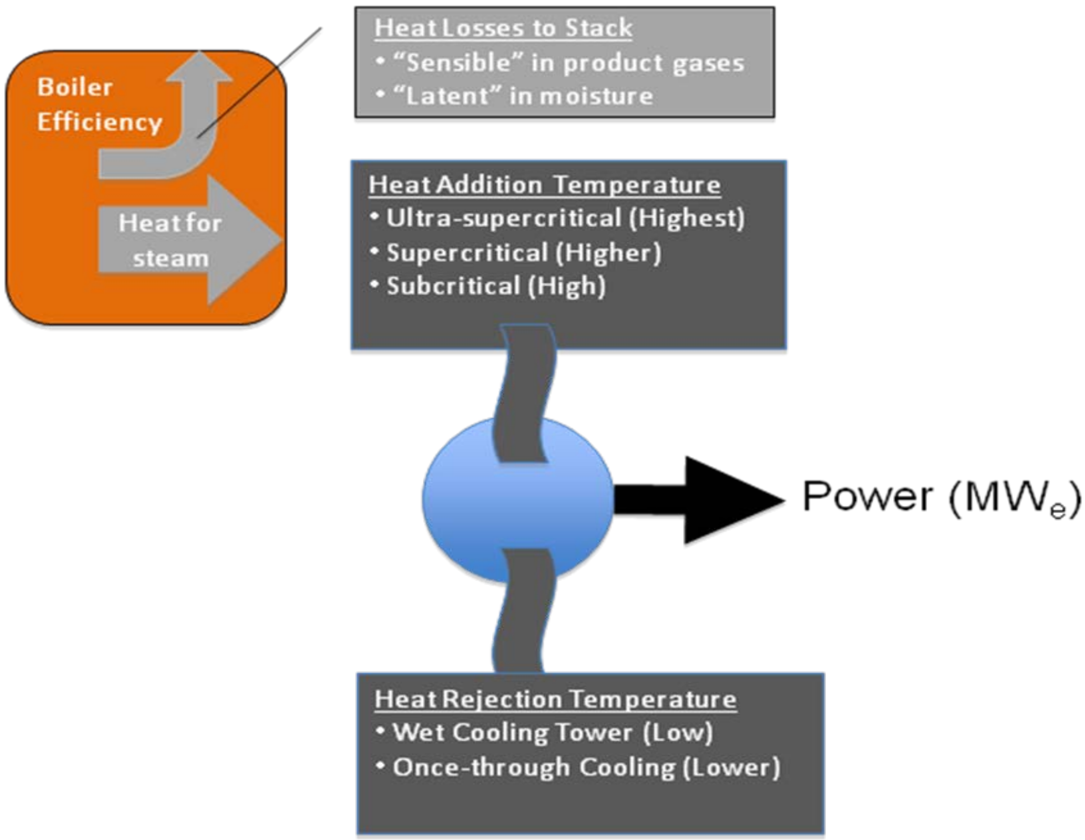

Figure 3-1. Heat Engine Diagram: Influence of Boiler Efficiency, Heat Addition, Heat Rejection Temperatures

The application of even higher steam pressures and temperature – exceeding 3,208 psig and 1,000-1,050°F – is referred to as "ultra-supercritical" conditions. At present, there is only one ultra-supercritical unit in the U.S. that is commercially operating. The American Electric Power (AEP) Turk Station, which started operation in late 2012, is designed for ultra-supercritical steam conditions. The CO_2 emissions rate from the Turk unit, if proven over time to operate as designed, should be lower than supercritical units. Early results are presented in Section 6 which provide insight but are inadequate to establish a long-term trend.

Figure 3-1 also shows the temperature of heat rejection is important. The "Heat Rejection Temperature" box lists both wet cooling towers and once-through cooling as examples of options. Because the thermal efficiency of the power generation cycle increases as the temperature of heat rejection decreases, a once-through cooling system with relatively low temperature water from a deep lake or the ocean will enable higher thermal efficiency than a wet cooling tower, operating in the same climate. Other options to reject heat, not shown in Figure 3-1, are dry cooling towers and hybrids of wet and dry towers.

Ambient air temperature and relative humidity also affect thermal efficiency by influencing the temperature of heat rejection. The temperature of water from rivers or lakes is influenced by ambient conditions, and the performance of cooling towers in rejecting heat is determined by air temperature and relative humidity.

Finally, the physical size of the generating unit can affect thermal efficiency. The inherent losses in energy from a boiler, due to surface cooling and air entrainment, are a smaller percentage of total heat throughput for larger generating units. This trend is due to geometric factors such as the surface area/volume ratio of the gas paths and boiler.

GENERATING UNIT OPERATION

Operating factors that influence CO_2 emissions are coal composition and plant operating duty – specifically, time spent at full load versus partial load.

Coal Composition

The carbon content of the coal affects CO_2 released in the combustion process and the CO_2 generated per MWh, although only to a small extent. For example, a typical subbituminous coal from Wyoming's Powder River Basin will release about 200 lbs of CO_2 for each MMBtu of energy content, while an eastern bituminous from Pennsylvania will release about 215 lbs for each MMBtu.

A far greater impact of coal composition is the free moisture content, which affects boiler efficiency, or the amount of fuel energy converted to steam. As shown in Figure 3-1, higher moisture in the fuel provides a means for heat to escape to the stack – through the latent heat of evaporation – without contributing to generating steam. For example, a typical coal from Wyoming's Powder River Basin will contain over 30% moisture, compared to about 6% in an eastern bituminous coal from Pennsylvania, penalizing boiler thermal efficiency by 3%-5%.[6] As a result, a larger amount of fuel must be fired (and CO_2 released) to generate a fixed quantity of steam.

Load Factor

Generating power at full load is more efficient than at part load for a variety of reasons. One significant factor is the amount of "excess" air used for combustion. At part load, additional combustion air is used to maintain a minimum velocity of air at the burner, or of combustion products in the boiler "convective" section. This additional air for combustion – above and beyond what is needed for complete fuel utilization – helps transfer heat to the steam but also increases the sensible losses enabling heat to "leak" to the stack and ambient.

A second factor affecting part load operation is the fractional consumption of the auxiliary power. Ancillary equipment such as pulverizers and boiler feed pumps consume power

[6] Boiler thermal efficiency per EPA's calculation procedure "CUECOST". Coal composition per EPA default values: Powder River Basin: 48.15% carbon, 3.31% hydrogen, 30.24% moisture, HHV of 8,227 Btu/lb. Eastern bituminous coal (Pennsylvania): 71.55% carbon, 4.88% hydrogen, 6.0% moisture, HHV of 13,100 Btu/lb.

that, as a fraction of the total plant output, is greater at partial loads. This factor affects only the "net" and not the "gross" plant output and emission rate.

Consequently, both coal composition and unit operation must be considered when evaluating the CO_2 emissions produced from a coal-fired power station.

SECTION 4

SELECTION OF REFERENCE COAL-FIRED POWER PLANTS FOR ANALYSIS

Selecting the reference coal-fired plants as the basis of the analysis is the first step in characterizing CO_2 emission rates from state-of-art generating equipment. This section identifies the coal-fired power plants that have entered commercial service since 2007, the criterion used to represent state-of-art coal-fired power plants, and the plants selected.

NEW COAL-FIRED PLANT INVENTORY

A total of 55 electric generating units that fire coal exclusively, or as a blend with a secondary fuel, have begun commercial service since January 1, 2007. Table 4-1 identifies these units in order of the month and year of startup. Table 4-1 reports for each plant the boiler type (fluidized bed, or pulverized coal with subcritical, supercritical, or ultra-supercritical steam conditions), the design "nameplate" generating capacity (MW), the current generating capacity (MW), and fuel type.

The inventory of coal-fired generating units in Table 4-1 reflects a wide variety of applications: large central stations generating power for distribution, small commercial units generating power for industrial applications, and units generating both heat and power for commercial manufacturing or material processing. Thus, many entries in Table 4-1 do not reflect the large, centrally located generating units that are the subject of the NSPS.

SELECTION CRITERIA

The following selection criteria were used to identify reference units for state-of-art coal-fired units that could be permitted in the present regulatory environment.

<u>Fuel Type</u>. Any unit must exclusively fire domestic U.S. coal – bituminous, subbituminous, or lignite. The use of petroleum coke or biomass fuels will alter the CO_2 emission rate, and possibly the duty cycle.

<u>Generating Capacity</u>. Units of small generating capacity may not be able to utilize fuel as efficiently as larger units due to boiler design and combustion conditions. Also, the relatively small generating capacity may not be adequate to justify state-of-art improvements to process controls and steam conditions.

Table 4-1. Coal-Fired Units Initiating Service after January 1, 2007

Power Plant	Boiler	Unit Nameplate Capacity (MW)	Current Operating Capacity (MW)	Primary Fuel Type	Month Unit in Service	Year Unit in Service
Cross Unit 3	Subcritical	591	600	Bituminous Coal	1	2007
Roquette America ST Plant	Subcritical	34	32	Petroleum Coke	2	2007
Manitowoc Unit 9	Subcritical	63	58	Petroleum Coke	4	2007
Port Hudson Pulp & Printing Paper	Subcritical	60	60	Petroleum Coke	5	2007
Walter Scott, Jr. Energy Center	Supercritic	923	818	Subbituminous Coal	6	2007
Wygen Unit 2	Subcritical	95	95	Coal	1	2008
TS Power Plant	Subcritical	242	228	Coal	5	2008
Weston Unit 4	Supercritic	595	554	Subbituminous Coal	6	2008
Cross Unit 3	Subcritical	652	600	Bituminous Coal	10	2008
Haverhill Cogeneration Facility	Subcritical	67	53	Bituminous Coal	12	2008
Clinton	Subcritical	75	75	Subbituminous Coal	2	2009
Clinton	Subcritical	105	105	Subbituminous Coal	4	2009
H.L. Spurlock Unit 4	Fluid Bed	329	268	Bituminous Coal	4	2009
Lamar Repowering Unit 4 (Fluid Bed)	Fluid Bed	25	25	Subbituminous Coal	4	2009
Lamar Repowering Unit 6 (Fluid Bed)	Fluid Bed	19	15	Subbituminous Coal	5	2009
Nebraska City Unit 2	Subcritical	738	685	Subbituminous Coal	5	2009
Perry K Unit 7	Subcritical	2	2	Bituminous Coal	6	2009
Perry K Unit 8	Subcritical	2	2	Bituminous Coal	6	2009
Smart Papers 1	Subcritical	1	1	Bituminous Coal	6	2009
Smart Papers 2	Subcritical	2	2	Bituminous Coal	6	2009
Smart Papers 7	Subcritical	9	9	Bituminous Coal	6	2009
Smart Papers 8	Subcritical	9	9	Bituminous Coal	6	2009
Sandow Unit 5	Fluid Bed	662	570	Lignite	9	2009
Columbus Cogen Unit 1	Subcritical	1	1	Coal	11	2009
Springerville Unit 4	Subcritical	450	415	Subbituminous Coal	12	2009
Dallman Unit 4	Subcritical	280	208	Bituminous Coal	1	2010
Oak Grove Project Unit 1	Supercritic	917	840	Lignite	1	2010
Brame Energy Center (Rodemacher 3) (Madison Unit	Fluid Bed	600	628	Petroleum Coke	2	2010
Elm Road Generating Station (Oak Creek) Unit 1	Supercritic	701	636	Bituminous Coal	2	2010
Wygen 3	Subcritical	116	100	Subbituminous Coal	4	2010
Archer Daniels Midland - Columbus	Subcritical	71	61	Coal	5	2010
Red River Parish-PAC	Subcritical	18	18	Coal	5	2010
Comanche Unit 3	Supercritic	857	783	Subbituminous Coal	7	2010
Plum Point Energy	Subcritical	720	670	Coal	9	2010
East Campus Utility Plant ST	Subcritical	1	1	Bituminous Coal	11	2010
Iatan Unit 2	Supercritic	914	881	Subbituminous Coal	12	2010
J.K. Spruce Unit 2	Subcritical	878	780	Subbituminous Coal	12	2010
Marina Thermal	Subcritical	8	8	Coal	12	2010
Oak Grove Project Unit 2	Supercritic	879	825	Lignite	NA	2010
Elm Road Generating Station (Oak Creek) Unit 2	Supercritic	615	634	Bituminous Coal	1	2011
John Twitty Energy Center (Southwest Power)	Subcritical	300	282	Coal	1	2011
Trimble County Unit 2	Supercritic	760	761	Bituminous Coal	1	2011
Marshall Plant	Subcritical	2	2	Lignite	3	2011
Whelan Energy Center Unit 2	Subcritical	248	225	Subbituminous Coal	5	2011
CFB Power Plant	Subcritical	155	143	Petroleum Coke	8	2011
Dry Fork Station	Subcritical	422	390	Coal	11	2011
Longview Power	Supercritic	695	700	Coal	12	2011
Middletown Cogeneration	Subcritical	67	47	Coal	12	2011
CFB Power Plant	Fluid Bed	155	143	Petroleum Coke	1	2012
Prairie State Energy Campus Unit 1	Supercritic	800	800	Bituminous Coal	6	2012
Virginia City Hybrid Energy Center (Fluid Bed)	Fluid Bed	600	600	Bituminous Coal	7	2012
Prairie State Energy Campus Unit 2	Supercritic	800	800	Bituminous Coal	11	2012
Cliffside Unit 6	Supercritic	825	825	Coal	12	2012
John W. Turk, Jr. (Ultra-supercritical)	Ulra-Super	609	609	Coal	12	2012
Edwardsport	IG/CC	618	618	Coal	6	2013
Sandy Creek	Supercritic	925	925	Coal	4	2013

Cooling System. As described in Section 3, the use of once-through cooling will affect heat rejection and plant thermal efficiency. The EPA, through the Clean Water Act's Section 316(b) rule, has essentially prohibited the use of once-through cooling from naturally-occurring water bodies for new generating units.[7] As described in Section 3, the use of once-through cooling will affect heat rejection and plant thermal efficiency. Consequently, any units using once-through cooling employing water from a natural water body could not be permitted in the present regulatory environment, and thus are not considered reference units.

Emission Data Availability. Reference units must have entered commercial service on or after January 1, 2007, and provided at least 18 months of continuous data by December 31, 2013.

Applying these selection criteria to the units summarized in Table 4-1 eliminates 35 units from consideration. The units that are eliminated are indicated by the shaded areas on Table 4-1 and discussed according to the selection criteria as follows:

Firing or Co-Firing Petroleum Coke. Roquette America ST Plant; Manitowoc Unit 9; Port Hudson Pulp & Paper; Brame Energy Center; CFB Power Plant.

Firing or Co-Firing Biomass. Virginia City Hybrid Energy Center.

Unrepresentative (Small) Generating Capacity. Haverhill Cogeneration; Clinton units; Lamar Repowering units; Perry K units; Smart Papers units; Columbus Cogen; Archer Daniel Midland – Columbus; Red River Parish – PAC; East Campus Utility Plant; Marina Thermal; Marshall Plant; Middletown Cogeneration; Wygen 2 and 3.

Once-Through Cooling From Natural Water Bodies. We Energies Elm Road (Oak Creek) Units 1 and 2 utilize once-through cooling from Lake Michigan.

Inadequate Operating Time. Several units in Table 4-1 had not accrued adequate operating time by December 31, 2013 to be considered as reference cases. For many units first year operation is atypical, as significant portions of operating time are devoted to "shakedown" and performance testing. The following units were judged to not offer adequate data to reliably assess CO_2 emission rates: Prairie State Units 1 and 2, Duke Cliffside Unit 6, AEP John W. Turk, Jr., Sandy Creek, and Duke Edwardsport. Although data from these units are inadequate to project long-term trends, one year of data is available for most and is discussed in Section 6.

DISCUSSION OF REFERENCE UNITS

The units in Table 4-1 proposed to reflect state-of-art coal-fired generating plants firing either subbituminous, bituminous, and Texas lignite coal are discussed as follows:

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[7] Section 316 (b) does not restrict once-through cooling from artifical lakes or cooling ponds constructed for the purpose of serving the generating plant.

Ten Subcritical Units

Data from ten subcritical pulverized coal units are considered for this analysis: eight fire PRB and two fire eastern bituminous coal.

PRB-fired units include: TS Power Plant; Omaha Public Power District's Nebraska City Unit 2; Springerville Unit 4 (owned by Tucson Electric Power); Plum Point Energy; J.K Spruce Unit 2; John Twitty Energy Center; Whelan Energy Center; and the Dry Fork Station. Two subcritical units that fire eastern bituminous coal included in this analysis are the City of Springfield (IL) Dallman Unit 4 and Santee Cooper Cross Unit 3[8].

Nine Supercritical Units

Data from nine supercritical units are evaluated firing coals designated as follows: four firing PRB, three firing eastern bituminous, and two firing Texas lignite.

PRB-fired supercritical units include MidAmerican Energy's Walter Scott Jr. Unit 4, WP&L's Weston Unit 4, Xcel Comanche Unit 3, and KCP&L's Iatan Unit 2 (Power Magazine's 2011 Plant of the Year).[9] Four supercritical units firing eastern bituminous coal are Duke Energy's W.H. Zimmer Unit 1, LG&E's Trimble County Unit 2, and First Reserve's Longview Power. In addition to these PRB-fired and bituminous-fired units, Luminant Power's Texas lignite-fired supercritical Oak Grove Units 1 and 2 are included in this analysis.

Three CFB subcritical boilers at two generating stations are also considered. These are E. Kentucky Power's Spurlock Unit 4, and Boilers 5A and 5B at Luminant's Sandow Unit 5.

This analysis cites data from the sole ultra-supercritical unit in operation – AEP Turk – but does not use this data due to limited experience. Also, presently available data are inadequate to characterize CO_2 emissions from Prairie State Units 1 and 2, Duke Cliffside Unit 6, Sandy Creek, and Duke's Edwardsport IG/CC unit.

This analysis does not consider data from early-generation IG/CC technology. Specifically, two IG/CC units producing power in the U.S. – at Tampa Electric's Polk and Duke Energy's Wabash River Station – are valuable precursors of this technology but do not represent state-of-art equipment. Both Duke Energy's Edwardsport IG/CC, which began operation in 2013 and Mississippi Power's Kemper County Energy Facility, which is under construction, employ state-of-art technology. Data from Edwardsport are limited and highly variable and Kemper County will not be operable until 2015. Both Edwardsport and Kemper County will not generate meaningful data for at least another year. Consequently, IG/CC results are not considered in this analysis.

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[8] Although Santee Cooper Units 3 and 4 are listed as candidate reference units in Table 4-1, discussions with plant staff indicated Unit 3 to be the more representive of the two. Consequently, Unit 4 CO_2 data were not considered other than for preliminary screening, as noted further in Section 5.

[9] Power Magazine, "Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor", August 1, 2011. Available at: http://www.powermag.com/environmental/Plant-of-the-Year-KCP-and-Ls-Iatan-2-Earns-POWERs-Highest-Honor_3882_p3.html.

SECTION 5

CO_2 EMISSION RATES FROM REFERENCE UNITS

This section reports the CO_2 emission rates from the selected reference units discussed in Section 4.

As noted in Section 2, annual emission rates of CO_2 are calculated using EPA's Air Markets Program Data (AMPD).[10] The annual CO_2 emissions rate is expressed as tons of CO_2 emitted (converted to pounds) divided by gross load (in MWh) as reported in the AMPD.

It should be noted that Cross Unit 4 - an identical "sister" unit to Cross Unit 3 – was not included in the analysis after a review of CO_2 emissions data. Specifically, Cross Unit 4 exhibited CO_2 emissions that differed from Unit 3 for unknown reasons. Discussion with the owner suggested Unit 3 data to be more representative of commercial operation; thus only Unit 3 is evaluated.

CALCULATED CO_2 EMISSION RATE

Figure 5-1 depicts CO_2 emission rates, in term of mass of CO_2 per power output (lbs/MWh), for the seventeen subcritical and supercritical units – twelve firing PRB and five firing eastern bituminous pulverized coal. Figure 5-2 depicts the CO_2 emission rates from five additional units. Two units fire pulverized Texas lignite, and three circulating fluid bed boilers firing either eastern bituminous or Texas lignite.

Ten Subcritical Units

Ten units with subcritical boilers are shown in Figure 5-1. Eight units fire PRB: TS Power Plant, Nebraska City Unit 2, Springerville Unit 4, Plum Point, JK Spruce Unit 2, John Twitty Energy Center, Whelan, and Dry Fork. Two units with subcritical boilers fire eastern bituminous coal: Dallman Unit 4 and Cross Unit 3. These ten units all emit CO_2 at levels greater than 1,800 lbs/MWh, in some cases by a significant margin.

[10] http://ampd.epa.gov/ampd/QueryToolie.html and ftp://ftp.epa.gov/dmdnload/emissions/.

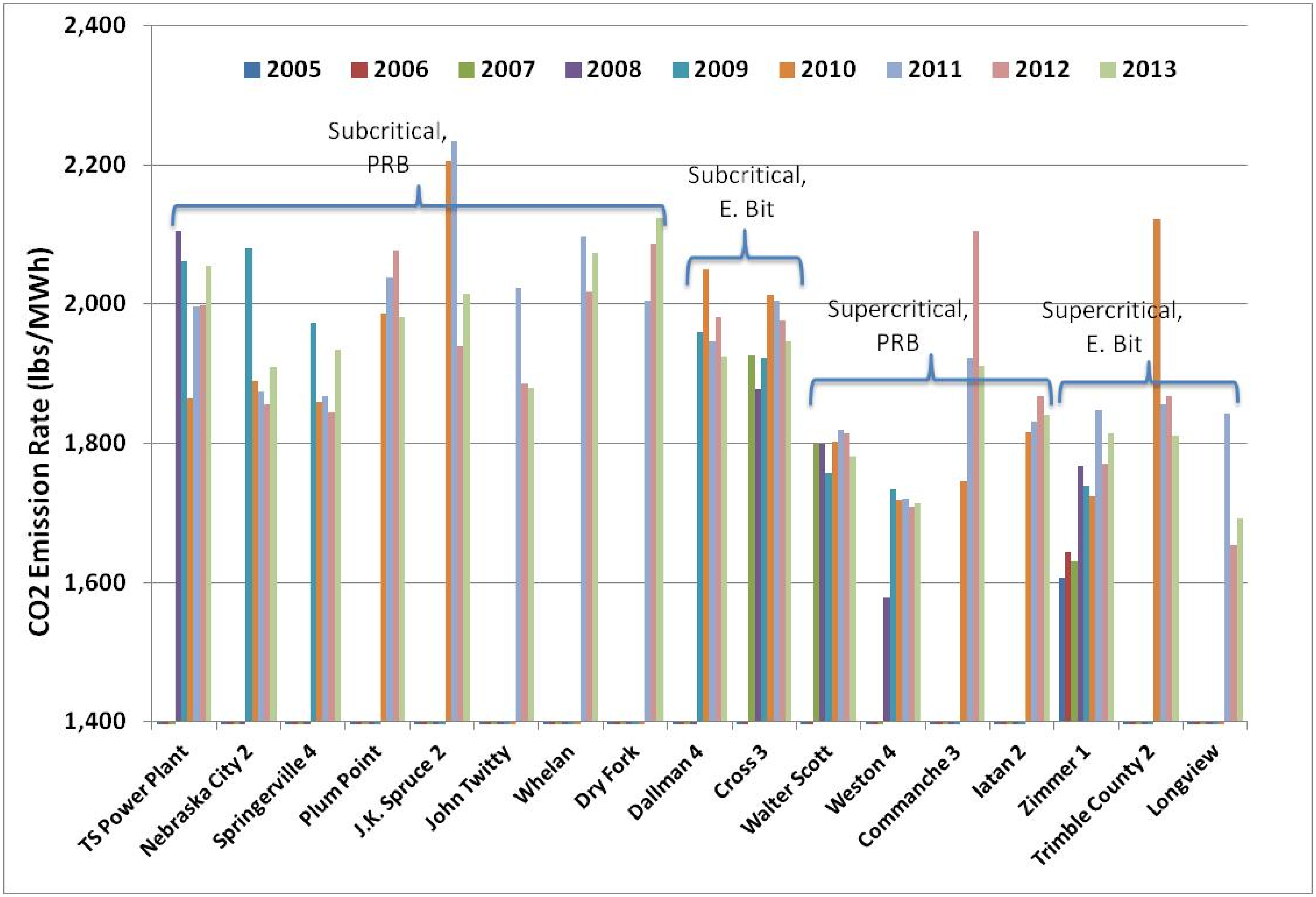

Figure 5-1. CO_2 Emissions Rate (lb/MWh) by Operating Year: Recent Commercial Pulverized Subbituminous/Bituminous Coal-fired Units

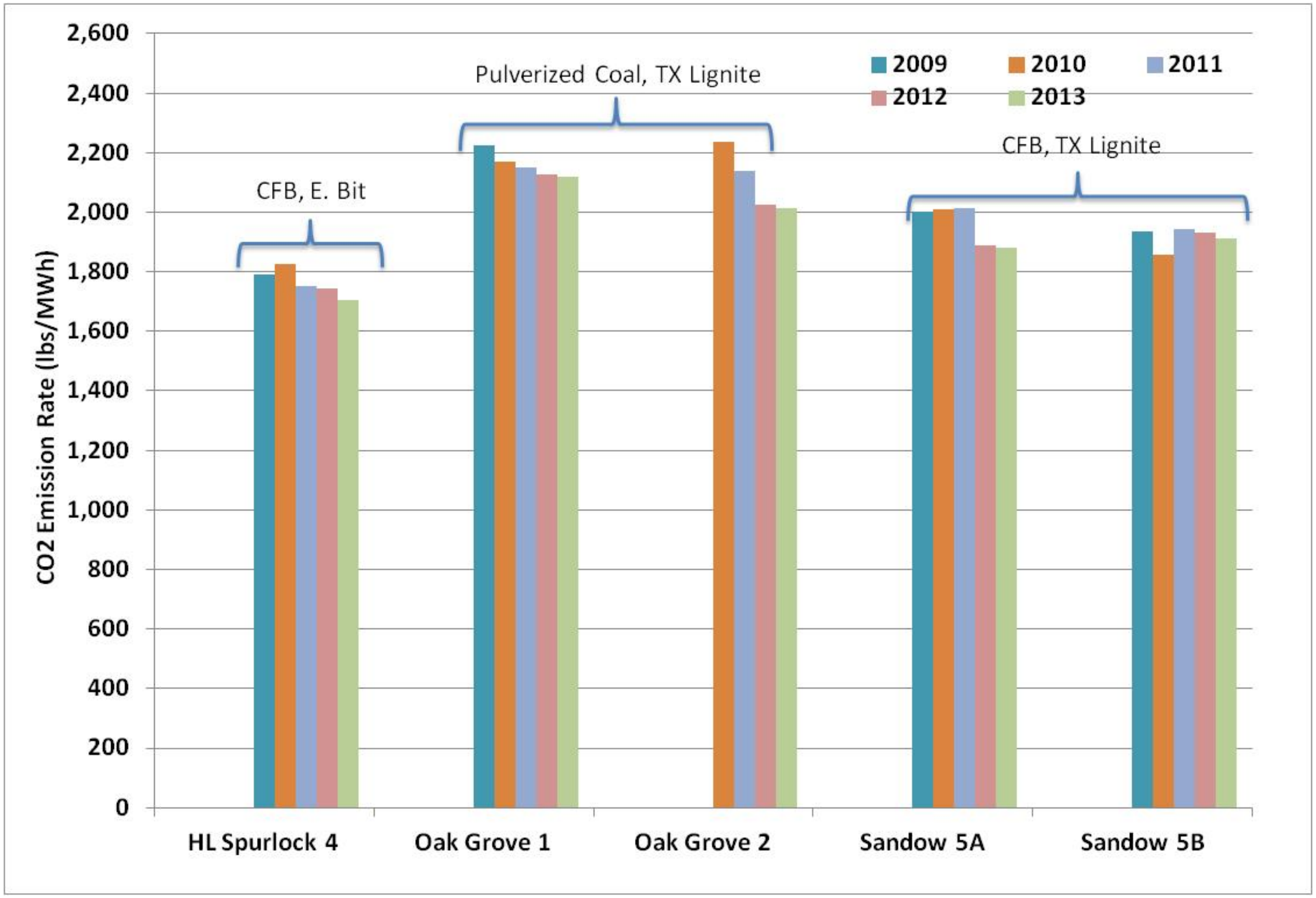

Figure 5-2. CO_2 Emissions Rate (lb/MWh) by Operating Year: Recent Commercial Circulating Fluid Bed and Texas Lignite-fired Units

The CO_2 emission rates are discussed for subbituminous and bituminous coals as follows:

Subbituminous. The CO_2 emissions rate for JK Spruce Unit 2 is among the highest noted at approximately 2,200 lbs/MWh for the first two years. The CO_2 emissions rate decreased substantially to 1,900-2,000 lb/MWh for the latter two years. Excluding the first year of operation, only three units emit at about 1,900 lbs CO_2/MWh or less – Nebraska City Unit 2, Springerville Unit 4, and the John Twitty Energy Center. Two of the newest units – Whelan and Dry Fork – emit CO_2 at greater than 2,000 lbs/MWh in the first years of operation.

Bituminous. Both the bituminous–fired Dallman Unit 4 and Cross Unit 3 emit CO_2 at a rate between 1,900 and 2,000 lbs/MWh. The bituminous-fired Cross Unit 3 emitted CO_2 at approximately 1,900 lbs/MWh or less for three of the seven years.

Figure 5-2 shows that CO_2 emissions from H.L. Spurlock Unit 4 – the sole bituminous-fired CFB unit in the reference units- are approximately 1,800 lbs/MWh.

Nine Supercritical Units

CO_2 emissions from seven units with supercritical boilers are shown in Figure 5-1 – four firing PRB and three firing bituminous coal. Figure 5-2 presents results from two supercritical units firing Texas lignite. The CO_2 emission rates from these units vary widely. Specifically:

Subbituminous. The Walter J. Scott Jr. Energy Center has emitted CO_2 at a rate equal to or below 1,800 lbs/MWh for most operating years, while emissions from Weston 4 are approximately 1,700 lbs/MWh for all six years. Comanche Unit 3 emitted less than 1,800 lbs/MWh of CO_2 in the first year but emissions increased to about 1,900 lbs/MWh or greater in subsequent years. Iatan Unit 2 emitted CO_2 between 1,800 and 1,900 lbs/MWh for the three operating years.

Bituminous. Almost all W.H. Zimmer data over nine years report CO_2 emissions less than 1,800 lbs/MWh. The CO_2 emissions rate from Trimble County Unit 2, excluding the first year, are between 1,800 and 1,900 lbs/MWh. Longview Power emitted CO_2 in excess of 1,800 lbs/MWh in the first partial year of operation, but below 1,700 lbs/MWh in the subsequent two years.

Lignite. Almost all CO_2 emissions data from both Oak Grove Units 1 and 2 are between 2,000 lb/MWh and 2,200 lb/MWh. Emissions of CO_2 from the two Sandow CFB boilers are between 1,900 and 2,000 lbs/MWh.

CO_2 emission rates for these classes of generating units are described in Section 6.

SECTION 6

DATA ANALYSIS AND OBSERVATIONS

This section evaluates trends in CO_2 emissions data in terms of unit design and operation.

Figure 5-1 presented CO_2 emissions data for seventeen units. Discussion in this section will further explore factors that contribute to the variability in CO_2 emission rates, and aggregate the data into three categories distinguished by boiler type and the use of lignite.

LOW EMITTING UNITS

The CO_2 emissions from the four lowest emitting units are discussed below.

Weston Unit 4

As befitting this unit recognized by Power Magazine as "2007 Plant of the Year," the 600 MW supercritical boiler employs state-of-art steam conditions.[11] Most notably, this unit features the highest main steam temperature (1,085°F) and turbine throttle temperatures (1,080°F) of any unit built in the U.S. as of 2007. The boiler also features eight stages of feedwater heating and "spiral wound" tubing in the furnace to minimize the thermal efficiency penalty at lower loads.

Walter Scott Jr. Energy Center Unit 4

This 890 MW plant was also recognized by Power Magazine, as "2008 Plant of the Year".[12] This unit employs state-of-art supercritical conditions with similar main steam (1,057°F) and turbine throttle temperatures (1,050°F), a "spiral wound" furnace, and eight stages of feedwater heating.

Longview Power

Longview Power fires bituminous coal in a 765 (695 net) MW supercritical unit. This boiler, distinguished as the world's first supercritical FW-Benson vertical boiler, generates supercritical steam at a temperature of 1056°F and pressure of 3840 psia, powering a single reheat turbine.[13]

[11] Power Magazine, "Wisconsin Public Service Corp's Weston 4 Earns Power's Highest Honor", August 15, 2008. Available at: http://www.powermag.com/coal/Wisconsin-Public-Service-Corp-s-Weston-4-earns-POWERs-highest-honor_1384_p2.html.
[12] Power Magazine, "MidAmerican's Walter Scott Jr. Energy Center Earns Power's Highest Honor", August 15, 2007. Available at: http://www.powermag.com/coal/MidAmericans-Walter-Scott-Jr-Energy-Center-Unit-4-earns-POWERs-highest-honor_210.html.
[13] Goidich, S.J., et al., "The World's First Supercritical FW-Benson Vertical PC Boiler – The 750 MW Longview Power Project.", Foster Wheeler North America Corp., Presented at Power-Gen India & Central Asia, New Delhi, India, May 5, 2011.

The boilers deployed for Weston Unit 4, Walter J. Scott, and Longview Power reflect state-of-art technology. Adopting these design features on smaller boilers is not always feasible, and the performance benefits may not be fully realized due to scale and operating duty.

WH Zimmer Unit 1

Zimmer Unit 1 emitted CO_2 at less than 1,800 lbs CO_2/MWh for each reported year except for 2011; this extremely large (1,425 MW) boiler is capable of exploiting significant economies of scale to maximize the efficiency benefits of advanced steam conditions. Many key components of this generating unit other than the boiler trace their legacy to being converted from a nuclear generating plant. Specifically, the low-pressure steam turbine and cooling tower were initially designed for nuclear duty but were adapted to the present coal-based duty.

Figure 6-1 presents CO_2 emissions from Zimmer Unit 1 versus the plant heat throughput – a surrogate for generating capacity output. Figure 6-1 shows the lowest CO_2 emissions were achieved at the highest heat throughput. The data show Zimmer's CO_2 emissions increase almost continuously as heat throughput decreases, with recent data exceeding 1,800 lbs/MWh for the least heat throughput.

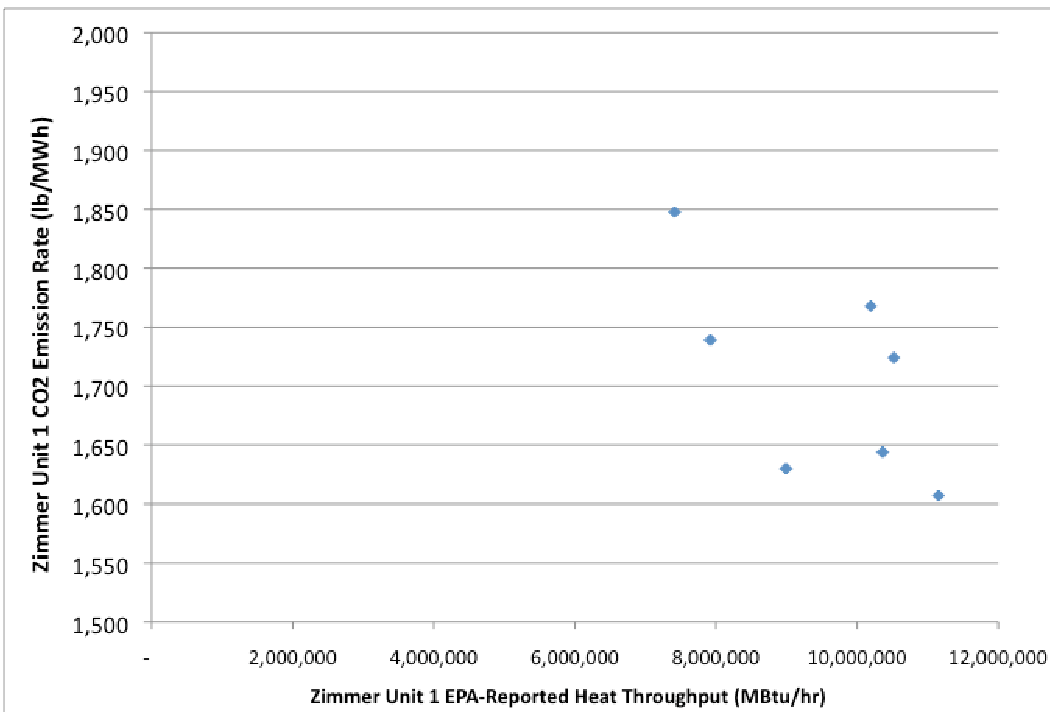

Figure 6-1. Relationship between Annual CO_2 Emitted, Average Heat Throughput

As discussed in Section 3, heat throughput rate (or load factor) can affect boiler thermal efficiency, steam turbine performance, and thus plant heat rate and CO_2 emissions. This observation will subsequently be explored with all other reference units to determine how operating conditions affect CO_2 emissions.

ADDITIONAL REFERENCE UNITS

Analysis of data from the additional reference units is offered as follows:

Subcritical Boilers

Subcritical boilers are represented by a wide range of designs, from the modest-sized TS Power Plant (225 MW) to the 663 MW Nebraska City station.

Generating units of modest capacity (200-300 MW) may not be able to fully exploit thermal efficiency-improving means. Examples of such means on the "steam-side" are additional reheat stages in the steam turbine, multiple-stage feedwater heaters, or elevated (to supercritical) steam conditions. Conventional practice advises investing in supercritical steam conditions for units of modest generating capacity will not always pay off in fuel savings, and the benefits of thermal performance-improving features cannot always be fully realized.[14] As a result the CO_2-mitigating payoff of advanced steam conditions may be limited for modest-sized units.

Several units emitted CO_2 in the first operating year at a rate that significantly exceeded that of subsequent years: Springerville Unit 4, Nebraska City Unit 2, John Twitty Energy Center, and the Whelan Energy Center. The first two years of CO_2 emissions at J.K. Spruce are exceptionally high before reverting to about 1,950 lbs CO_2/MWh in the third year. The mean CO_2 emissions rate from these units exceeds that from supercritical units such as Walter Scott Jr. by about 5% and Weston Unit 4 by almost 10%.

Springerville Unit 4, although not of supercritical design, employs advanced thermal performance features. Unit 4 is an identical "sister unit" compared to Unit 3, the latter selected by Power Magazine as "2006 Plant of the Year".[15]

Steam conditions alone may not be responsible for the CO_2 emissions difference between Nebraska City Unit 2 and Springerville Unit 4, compared to Walter Scott Jr. Unit 4 and Weston Unit 2. The role of ambient temperature and the associated impact on cooling tower performance may be a factor. Figure 6-2 compares the monthly ambient temperature for 2011 for these four units, showing that for most operating months the

[14] See Expert Report and Analysis – Basin Electric Power Co-Operative's Dry Fork Station Power Plant: Testimony of Kenneth Snell, addressing why subcritical boiler technology was the only practical generating choice for the Dry Fork Station (page 9), and why supercritical boiler efficiency gains are not applicable to the Dry Fork Station (page 12). Available at:
deq.state.wy.us/...2801%20Dry%20Fork%20Station/Earthjustice.Exhibit27.

[15] Power Magazine, "Tri-State Generation and Transmission Association's Springerville 3 Earns Power's Highest Honor", September 15, 2006. Available at: http://www.powermag.com/issues/cover_stories/Tri-State-Generation-and-Transmission-Associations-Springerville-Unit-3-earns-POWERs-highest-honor_594_p2.html.

Nebraska City 2 and Springerville 4 units reject heat into higher ambient temperatures. The difference in heat rejection temperatures may partially explain the higher CO_2 emissions from Nebraska City 2 and Springerville 4.

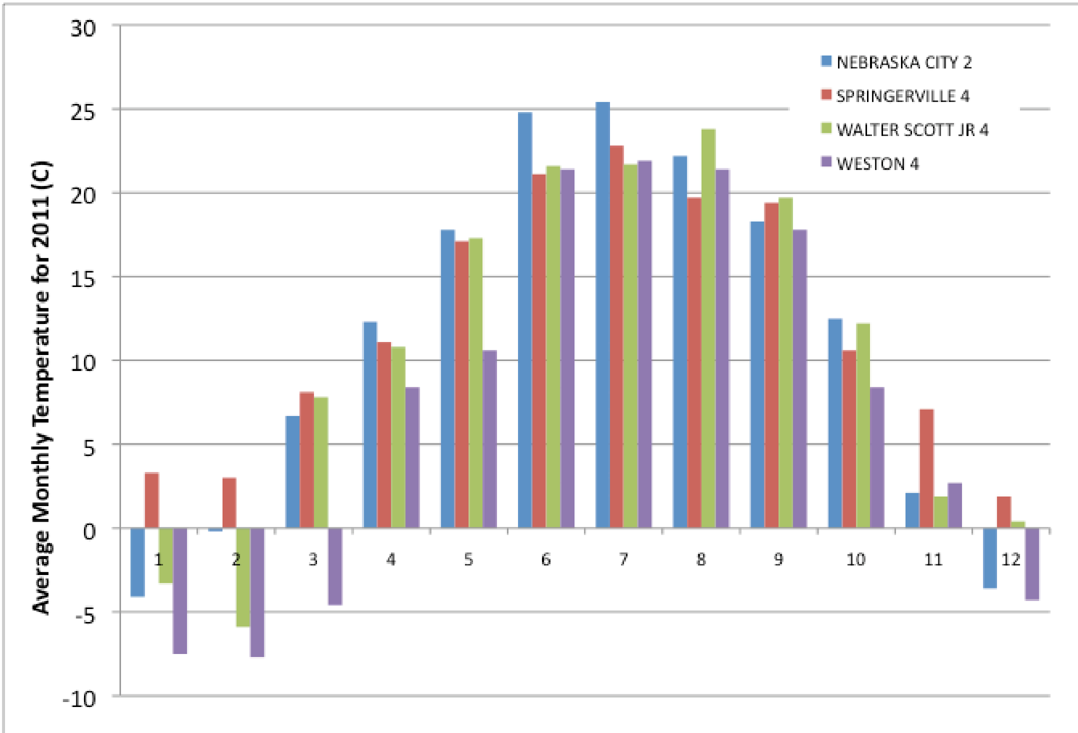

Figure 6-2. Monthly Ambient Temperatures for 2011 for Four PRB-fired Units

The CO_2 emissions rate from the two bituminous coal-fired units - Dallman Unit 4 and Cross Unit 3 – is higher than most PRB-fired subcritical units. As noted in the subsequent section addressing CFB units, Spurlock Unit 4 emitted CO_2 at a rate between 1,700 and about 1,800 lbs/MWh for all years of operation.

Supercritical Boilers

Subbituminous coal-fired supercritical boilers – Comanche Unit 3 and Iatan Unit 2 – emit in most reporting years CO_2 emissions between 1,800-1,900 lbs/MWh. Comanche Unit 3 did feature low CO_2 emissions in the first operating year (2010), and encountered aberrant emissions in 2012. The emissions rate in 2011 and 2013 are similar and may represent the long-term trend.

The eastern bituminous coal-fired supercritical Trimble County Unit 2, excluding the first year of operation where only 414 hours were reported, emits CO_2 at 1,800-1,900 lbs/MWh. Longview Power emitted CO_2 at a rate above 1,800 lbs/MWh in the first partial year (2011), but in 2012 and 2013 emitted at less than 1,700 lb/MWh.

Regarding lignite coal, Figure 6-2 shows that the Oak Grove supercritical units emit CO_2 at a rate exceeding 1,800 lbs/MWh by almost 25%. There are two possible reasons: the moisture content of the Texas lignite, and heat rejection into an artificial lake (with elevated temperatures in the summer).

Circulating Fluid Bed Boilers

Figure 5-2 shows the circulating fluid bed (CFB) boiler firing bituminous coal emits CO_2 at less than 1,800 lbs/MWh, while two separate CFB boilers firing Texas lignite (Sandow Units 5A and 5B) emit CO_2 between 1,900 lbs/MWh and 2,000 lbs/MWh.

ROLE OF OPERATING LOAD

The influence of load on the CO_2 emissions rate is explored to demonstrate that operating requirements – specifically the unit's dispatch to meet electricity demand – can affect CO_2 emissions.

Figure 6-3 depicts CO_2 emissions for three categories of hourly operating load, reported as the fraction of maximum generating capacity. These three categories are: full-load (>90%), high load (80-90%), and lower load (30-79%). The data presented in Figure 6-3 are based on the same hourly CO_2 emission rate that was used to construct Figures 5-1 and 5-2, but grouped by fraction of maximum operating load. The results are presented by boiler type and fuel, and discussed subsequently:

Subcritical

<u>Subbituminous</u>. Seven of the eight subcritical boilers firing subbituminous, specifically PRB, coal exhibit a strong relationship between hourly operating load and CO_2 emissions. All units except J.K. Spruce 2 emit CO_2 at a higher hourly rate when operating at less than 80% maximum load, by an amount that can be more than 100 lbs of CO_2 per MWh.

<u>Bituminous.</u> Only one subcritical pulverized coal boiler firing eastern bituminous coal – Cross Unit 3 – offers hourly CO_2 emissions data for all three categories of operating load. Cross Unit 3 emits slightly more CO_2 at less than maximum operating load. Hourly CO_2 emissions data are available for Dallman only at the lowest fraction of operating load (30-79%), so a trend between CO_2 emissions and operating load cannot be inferred.

Supercritical

<u>Subbituminous</u>. The subbituminous PRB-fired supercritical boilers at the Walter Scott Jr. Energy Center and Weston Unit 4 emit more CO_2 at less than 80% load, while data from Iatan are less conclusive. The trend in hourly CO_2 emissions with load for Comanche 3 is possibly distorted by low emissions in the first partial operating year, which may not represent typical operation.

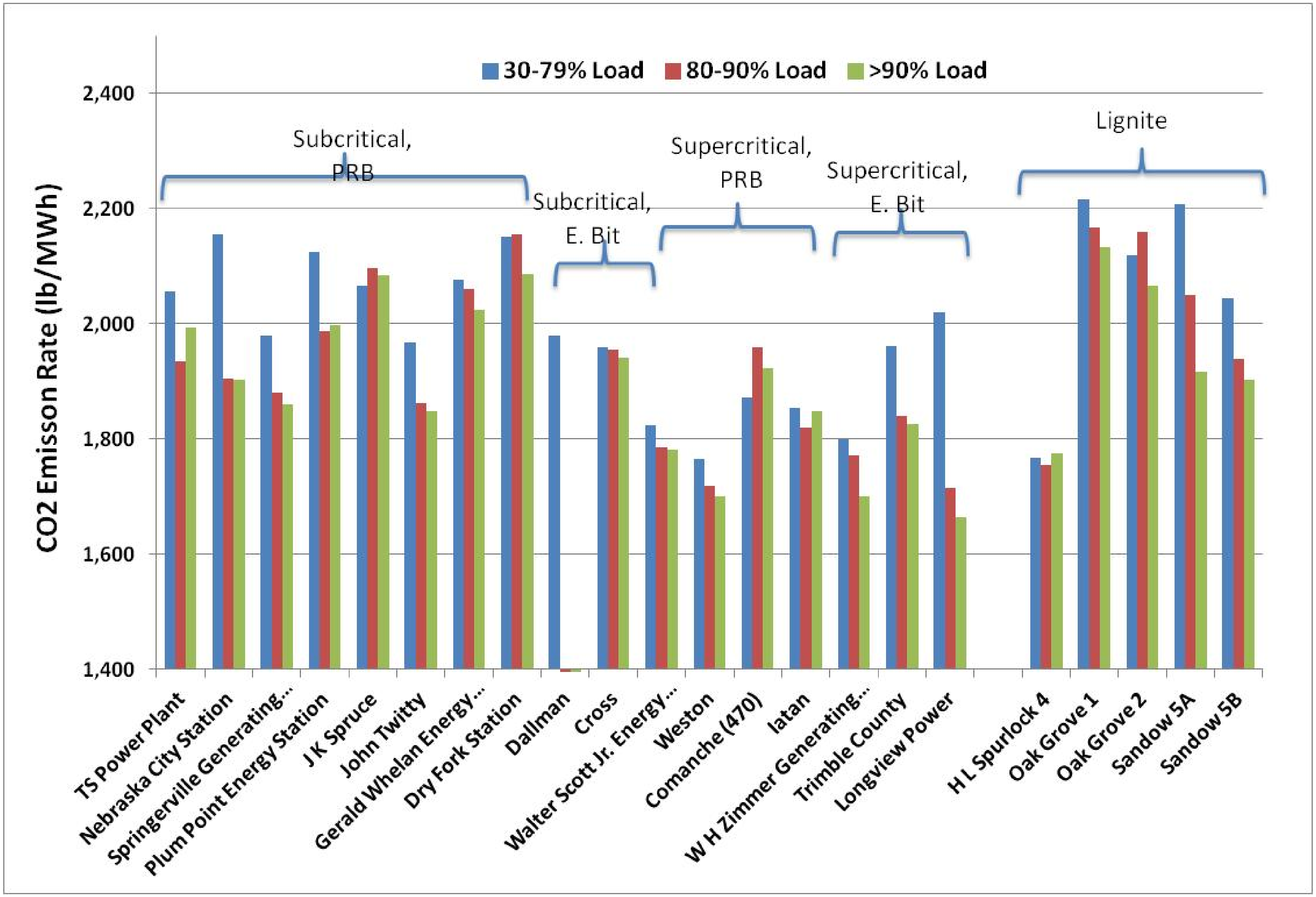

Figure 6-3. CO_2 Emissions (lbs/MWh) for EPA, Additional Reference Units: Results per Three Categories of Load

Bituminous. Eastern bituminous-fired supercritical boilers at Trimble County and W.H Zimmer 1 exhibit higher hourly CO_2 emissions when operating at less than 90% load. Longview Power exhibits a very strong relationship between load and CO_2 emissions, with near-full load CO_2 emission rate 70% of lower load emission rates.

Texas Lignite. Both Oak Grove units exhibit a relationship between daily CO_2 emissions and the fraction of operating load.

Circulating Fluid Bed (CFB) Units

The CO_2 produced from the subcritical bituminous-fired Spurlock generating unit is almost invariant with operating load, while the daily CO_2 emissions rate from the Texas lignite-fired Sandow Station increases at lower operating load.

The significance of Figure 6-3 should not be underestimated. The data show for most units that CO_2 emission rates increase when operating at less than maximum load. Specifically, the CO_2 emissions rate can increase by 100 lbs/MWh and in some instances by as much as 200 lbs/MWh. Figure 6-3 shows that using limited data derived from full load operation can be deceiving.

AVERAGING PERIOD: BLOCK VS. ROLLING

Emission rates for CO_2 were calculated using both a 12-month calendar year “block” average and a 12-month rolling average. The 12-month rolling average is calculated from 30-day averages, and updated by adding the latest and deleting the oldest data. The example cases considered operation after commissioning and startup operations were complete, and thus represent well-controlled commercial operation. The results of this analysis show no significant difference could be discerned using these two averaging methods. It is possible that under some conditions there could be a difference in the calculated “block” and 12-month rolling CO_2 averages. These operating conditions would be for less than a complete 12 months of operation, such as during commissioning and start-up, or after an extended maintenance outage.

AGGREGATED DATA POPULATION

Analysis presented so far has addressed annual CO_2 emissions from individual generating units. Additional insight to CO_2 emission trends can be provided by aggregating data from individual units into categories, defined by boiler type or fuel composition. This aggregating of data creates larger data sets that improve the “robustness” of subsequent statistical analysis.

Three categories are proposed: subcritical boilers firing subbituminous and bituminous coal, supercritical boilers firing subbituminous and bituminous coal, and lignite-fired boilers regardless of boiler steam conditions or design. The first two categories are distinguished by boiler steam conditions, independent of whether subbituminous and bituminous coal is fired. This categorization is based on the assessment that boiler steam conditions are more important in determining CO_2 emissions than fuel properties.

Lignite is designated as a separate category for two reasons. First, lignite coal presents firing and utilization challenges than can have a greater impact on CO_2 emissions than boiler design. Second, the data set for lignite coal is quite limited – there are only four units total, considering that Sandow 5 is essentially comprised of two boilers.

A further description of these data sets and results follows.

Data Set Construction

Subcritical Boilers. Subcritical boilers are considered a separate category because subcritical steam conditions lead generally to less efficient operation and higher CO_2 emissions.

The sole CFB boiler fired by bituminous coal operates at subcritical conditions and is included in the subcritical boiler subcategory.

Supercritical Boilers. Supercritical boilers are typically favored for large generating units that are anticipated to operate near full-load and at high capacity factor. The significant increase in steam pressure and temperature as delivered by a supercritical boiler – and the potential to drive boiler thermal efficiency higher – outweighs differences between subbituminous and bituminous coal.

Lignite. Lignite is unique in composition and physical features. Lignite features high moisture, but also high content of a tenacious ash that can be difficult to remove from heat transfer surfaces and thus inhibit boiler performance. These differences in fuel can be at least as important as differences in supercritical vs. subcritical steam conditions.

Lignite data are limited – there are only two supercritical pulverized coal boilers and two CFB boilers. Thus, all lignite data are considered in one data set regardless of boiler type.

As noted in Section 5, CO_2 emissions in the first year of operation for some units can differ from subsequent years. Many units operate for an abbreviated period in the first year; for example, Trimble County Unit 2 and Springerville Unit 4 each operated less than 500 hours in their start-up year. The aberrant CO_2 emissions levels could be due to any of the following: a reduced data set, evolving calibration of the continuous emission monitoring system (CEMS), and frequent startup and shutdown operation. Eliminating first year operating data just from those units with limited operating time was considered; however, to be consistent, first year data from all units were eliminated.

Cumulative Data Distribution

Figures 6-4 through 6-7 display daily CO_2 emissions for the cumulative population for each of the three categories. These figures report the fraction of the population of hourly CO_2 emissions (horizontal axis) that is at or below a given CO_2 emissions rate (vertical axis).

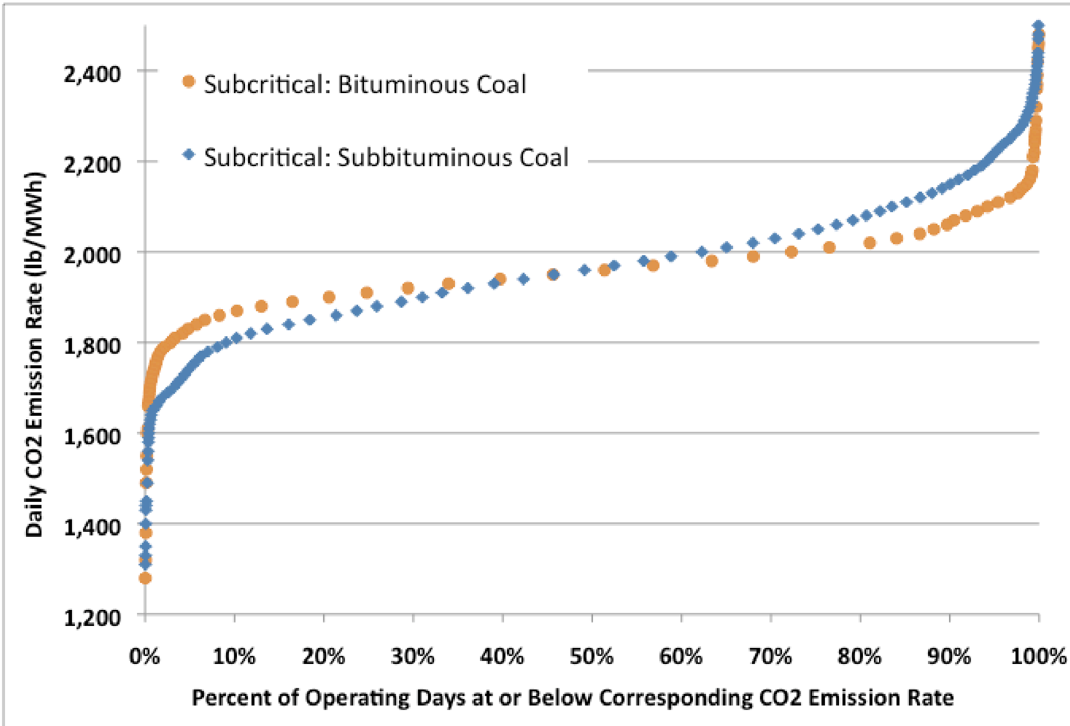

Figure 6-4. Cumulative Distribution of Daily CO_2 Emission Rate for Subcritical Boilers: Bituminous and Subbituminous Coal

Figure 6-4 presents the cumulative distribution of CO_2 data at or below a given CO_2 emission rate for subcritical boilers. Data are shown for both bituminous and subbituminous coals. The difference in CO_2 emission rate due to fuel type is considered relatively small, given the variability of the data and the size of the data set.

Figure 6-5 presents the cumulative distribution of CO_2 data at or below a given CO_2 emission rate for supercritical boilers. Data are shown for both bituminous and subbituminous coals, indicating CO_2 emission rates from bituminous coals are slightly lower than from subbituminous coals. The difference in CO_2 emission rate due to fuel type is considered relatively small given the variability of the data and the size of the data set.

As noted previously, there are several units of interest – designed for supercritical or ultra-supercritical steam conditions, or IG/CC - for which data are inadequate to describe CO_2 emission trends. Prairie State Unit 1 (supercritical) emitted CO_2 at 2,154 and 2,063 lbs/MWh in 2012 and 2013, respectively; however this unit was off-line for considerable time periods in both years and operation is believed atypical. Prairie State Unit 2 (supercritical) emitted CO_2 at 2,063 lbs/MWh for 9 months of 2013; as noted previously less than 12 months duty in the first operating year is not considered typical. Sandy Creek Unit 5 (supercritical) reported emitting CO_2 at 2,130 lb/MWh in the first full operating year of 2013. For ultra-supercritical Turk, the 2013 median and load-weighted average CO_2 emission rates – 1,800 and 1,817 lbs CO_2/MWh, respectively – are almost identical to the median values for bituminous-fired supercritical reference boilers in Figure 6-5. The CO_2 emissions load-weighted average for 2013 for supercritical Cliffside Unit 6 is 1,690 lbs/MWh. Finally, the 2013 CO_2 emissions data for Duke's IG/CC Edwardsport unit averages 2,065 lb/MWh. For all of these units, more than one year of operating data - not compromised by significant downtime - is required to confidently project emission trends.

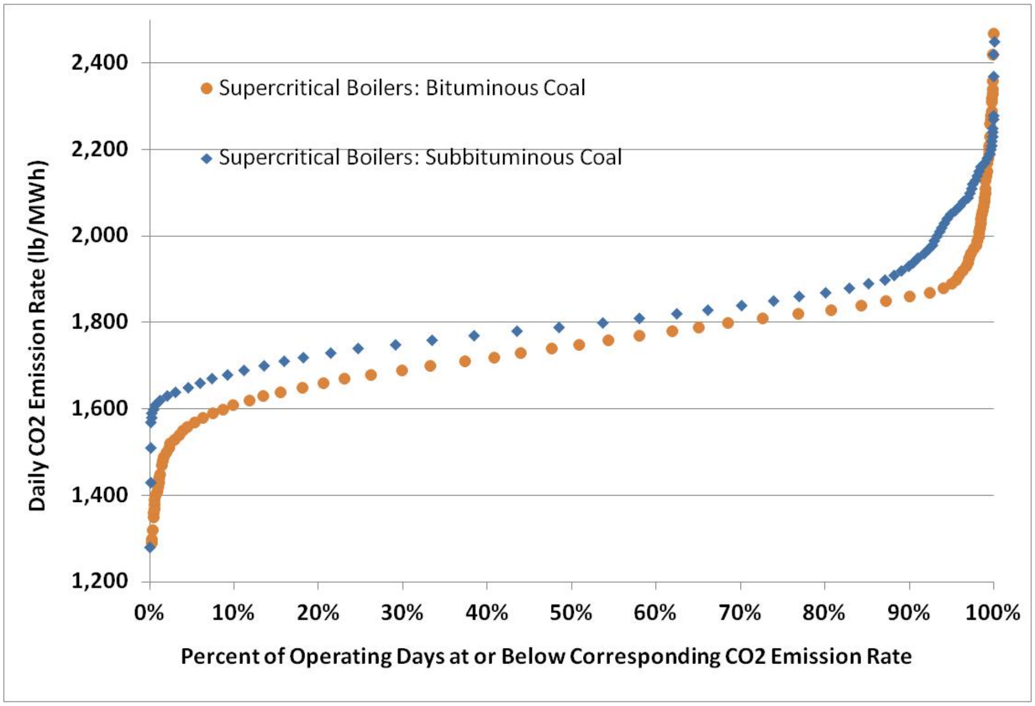

Figure 6-5. Cumulative Distribution of Daily CO_2 Emission Rate for Supercritical Boilers: Bituminous and Subbituminous Coal

Figure 6-6 presents the cumulative distribution of CO_2 data at or below a given CO_2 emission rate for lignite-fired boilers. Data are shown for both supercritical pulverized coal and subcritical fluid bed combustion boilers. There is a significant difference in CO_2 emissions between these two boiler types. Given the relatively small data set – two units from each type of boiler – the lignite coals are considered as one category.

Figure 6-7 summarizes data in Figures 6-4 and 6-5 for subcritical and supercritical boilers, but with subbituminous and bituminous data merged. Lignite data from Figure 6-6 is also summarized on Figure 6-7 after merging data from all boiler types.

Three groupings of data are evident for each of the subcritical boiler, supercritical boiler, and lignite fuel categories. The first approximately 10% of the data population comprise the lowest daily CO_2 emissions. These data mostly represent aberrant behavior due to atypical operating conditions – perhaps startup or shutdown, or CEMS reporting anomalies. The number of data points in this group is small and does not significantly affect the long-term CO_2 emissions rate.

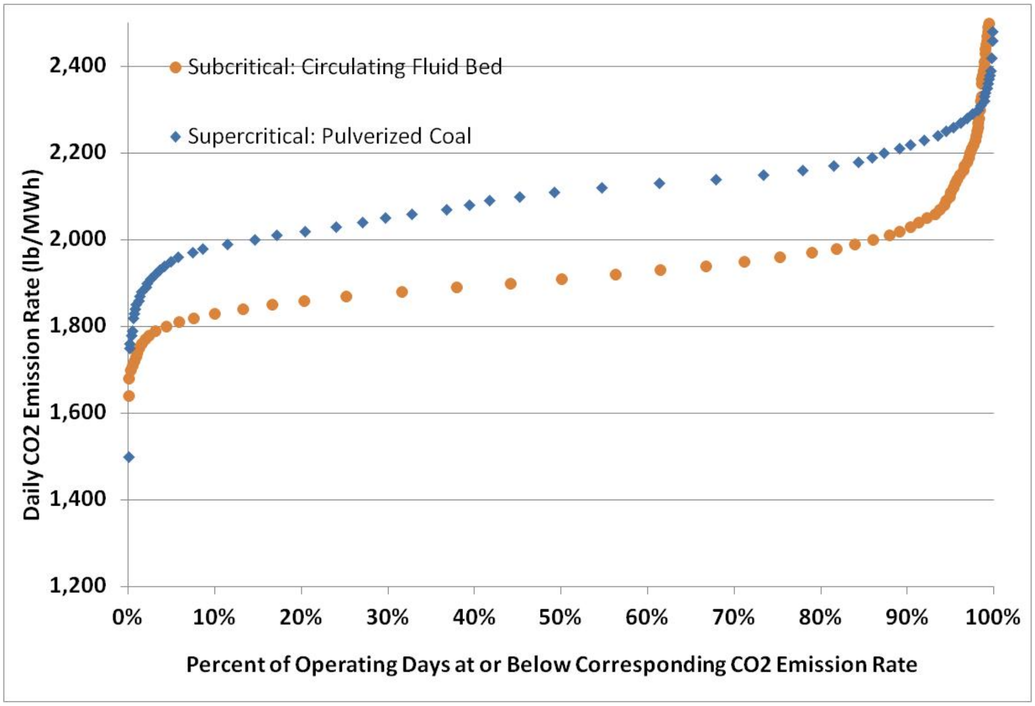

Figure 6-6. Cumulative Distribution of Daily CO_2 Emission Rate for Lignite-Fired Boilers: Subcritical Fluid Bed and Supercritical Pulverized Coal

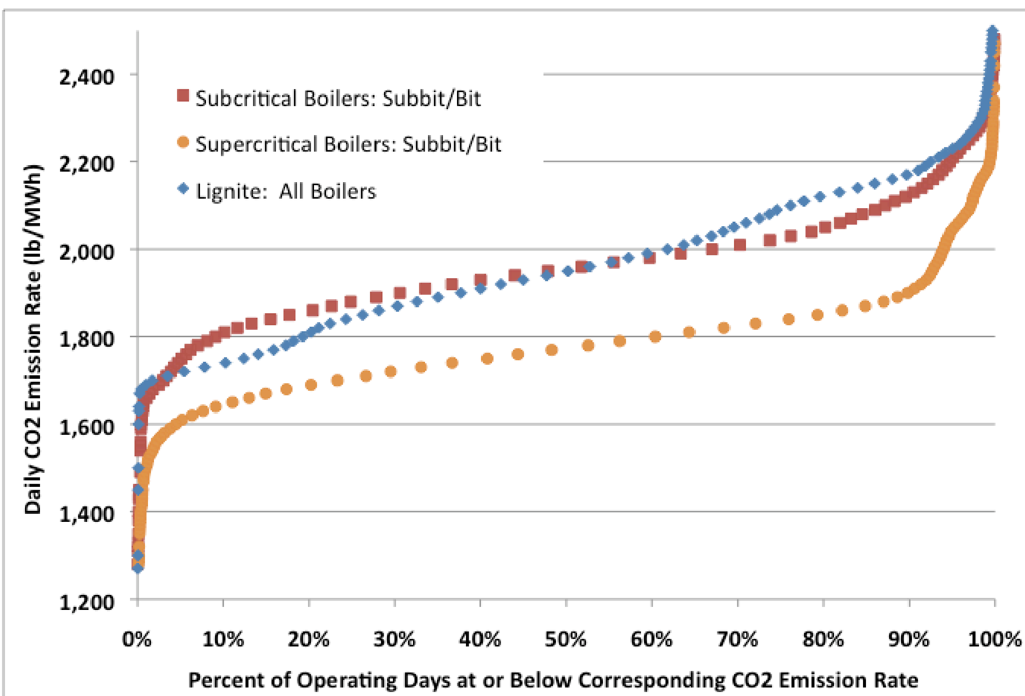

Figure 6-7. Cumulative Distribution of Daily CO_2 Emission Rate for Subcritical Boilers, Supercritical Boilers, and Lignite

The second group of emissions data exhibits an approximate linear relationship between CO_2 and the data population – from approximately 10% to about 85-95% of the population. The third group of data exhibits a nonlinear increase in hourly CO_2 emission rates in the final 85-95% of the population.

Figure 6-7 shows the CO_2 emissions rate for lignite fuels, when measured from all boilers (i.e., supercritical, subcritical, and circulating) is approximately equal to CO_2 emissions from subcritical boilers. The differences in the data for these two categories of boiler/fuel type are considered negligible, and due as much to differences in data population as inherent features of the fuel.

It is not appropriate to use the daily CO_2 emissions rate in Figure 6-7 to derive an annual CO_2 emissions rate. This is because the events that determine a calculated annual average – be it determined as a 12-month “block” or 30-day rolling average – are simply not reflected in the daily CO_2 data. For example, as suggested by Figure 6-2, ambient temperature can affect heat rejection, plant thermal efficiency, and CO_2 emissions. Further, as shown in Figure 6-3, CO_2 emissions depend on the operating load as a fraction of maximum capacity. Not all seasons of the year will require operating near full load, affecting CO_2 emissions.

Further analysis using a rigorous statistical method to translate daily data to annual emission rate data that has been applied by EPA in previous NSPS rulemaking is presented in Section 7.

SECTION 7

PROJECTING APPROPRIATE CO_2 EMISSION RATES

Section 7 employs the data presented in Sections 5 and 6 to project an appropriate CO_2 emission rate that would be "achievable" by the population of boilers considered. The methodology is adopted from that historically applied by EPA in setting New Source Performance Standards (NSPS). The methodology is applied to the data set for the three subcategories for coal-fired power plants, defined by boiler type and coal rank.

METHODOLOGY

The data available to project an "achievable" CO_2 emission target is limited, as 12 months of operation from each unit is required to produce a single data point. Therefore, the statistical methodology as described in EPA Report EPA-453/R-94-012, "New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NO_x Standard", June 1997, is applied to project annual CO_2 limits from daily averages.

Statistical Analysis

The statistical methods applied in this analysis, to the extent possible, were replicated from the method described in EPA Report EPA-453/R-94-012. The method specifically entailed:

- Calculating annual CO_2 emission rates (January 1 through December 31) for each unit for each year, screened and adjusted as described in the previous section.

- Confirming the data set is "normally" distributed and not "skewed" to one side. The data set, if not normally distributed, is typically adjusted using the Box-Cox Transformation. No such transformation was required for these data.

- Determining the mean value and standard deviation for the normal or adjusted-to-normal distribution.

- Determining the "Z-Factor," that with the mean value and standard deviation defines a CO_2 emissions rate for an associated probability of exceedance.

As in the EPA methodology, the CO_2 emissions rates determined to be "achievable" were those that one produced one projected exceedance of the 12-month average every ten years.

Projected "Achievable" CO_2 Emission Rates

Figure 7-1 summarizes CO_2 emission rates that have been calculated for each of the three categories based on EPA's statistical methodology. For purposes of comparison, Figure 7-1 also presents the projected CO_2 emissions rate for one exceedance per 20 years. The vertical axis shows the CO_2 emissions rate for which one exceedance per ten years would be expected. These values approximate:

- 1,915 lbs CO_2/MWh for supercritical boilers burning bituminous coal and subbituminous coals;

- 2,080 lbs CO_2/MWh for subcritical boilers burning bituminous and subbituminous coals; and

- 2,150 lbs CO_2/MWh for all boilers burning lignite coal.

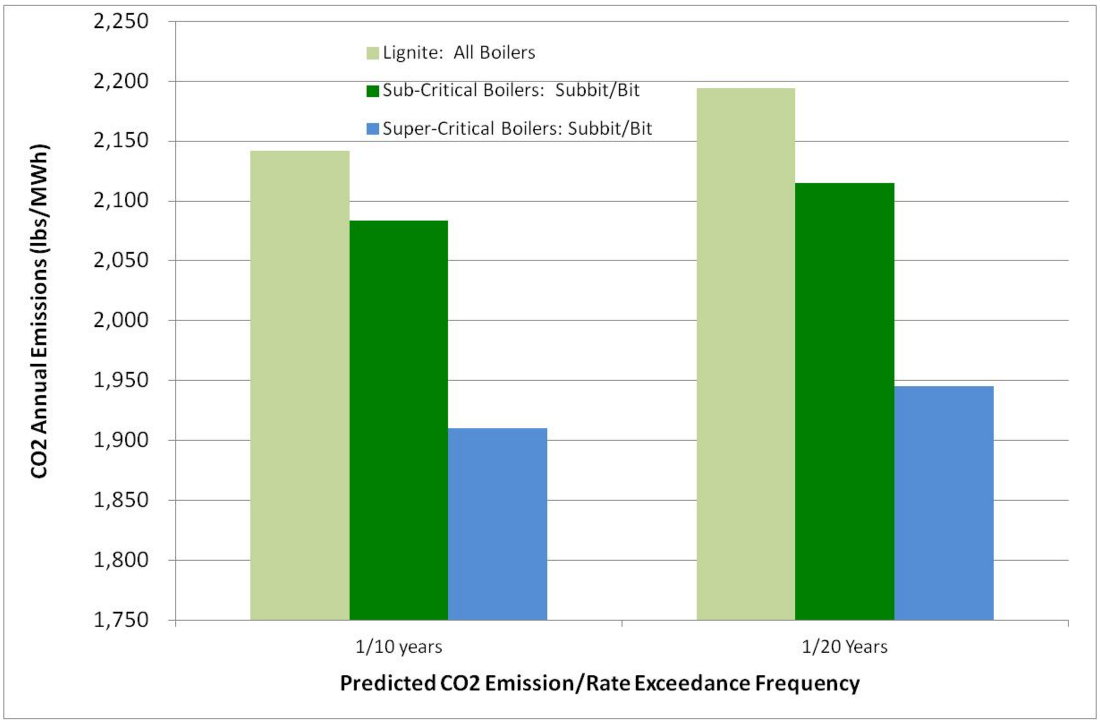

Figure 7-1. Achievable CO_2 Emission Rate for Subcritical Boilers, Supercritical Boilers, and Lignite: Exceedances of 1 in 10 (1/10) and 1 in 20 (1/20) Years.

Appendix 3

COMMENTS OF EDISON ELECTRIC INSTITUTE,
THE AMERICAN COALITION FOR CLEAN COAL ELECTRICITY,
THE NATIONAL MINING ASSOCIATION AND
THE COAL UTILITIZATION RESEARCH COUNCIL
ON THE ENVIRONMENTAL PROTECTION AGENCY'S
DRAFT UNDERGROUND INJECTION CONTROL PROGRAM GUIDANCE ON
TRANSITIONING CLASS II TO CLASS VI WELLS

EPA-816-P-13-004

February 28, 2014

The Environmental Protection Agency (EPA or Agency) issued *Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells, EPA-816-P-13-004* (Draft Guidance) in December 2013. The Edison Electric Institute (EEI) submits these comments on behalf of its members, as well as the American Coalition for Clean Coal Energy (ACCCE), the National Mining Association (NMA) and the Coal Utilization Research Council (CURC) (collectively, the Commenters).

UIC Class II wells inject carbon dioxide (CO_2) or other substances for the purposes of enhanced oil or gas recovery (collectively, enhanced recovery (ER)). UIC Class VI wells inject CO_2 for the purpose of long-term geologic storage (GS). EPA recognizes that some CO_2 injected into UIC Class II wells will be trapped in the subsurface. If there is no increased risk to underground sources of drinking water (USDW), the focus of the UIC program, these operations will continue to be permitted under Class II. However, if there is increased risk to USDW, these wells must be repermitted as Class VI wells. In the Draft Guidance, EPA lays out a framework addressing how and when Class II must make the "transition" to Class VI wells.

EEI is the association that represents all U.S. investor-owned electric companies, international affiliates and industry associates worldwide. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $85 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

ACCCE is a partnership of the industries involved in producing electricity from coal. Coal is an abundant and affordable energy resource that has provided nearly half of the reliable electricity Americans depend upon each and every day over the last decade. ACCCE supports policies that will ensure affordable, reliable, domestically produced energy, while supporting the development of advanced technologies to further reduce the environmental footprint of coal-fueled electricity generation—including advanced technologies to capture and safely store CO_2 gases.

NMA is a national trade association whose members produce most of America's coal, metals, and industrial and agricultural minerals. Its membership also includes manufacturers of mining and mineral processing machinery and supplies, transporters, financial and engineering firms, and other businesses involved in the nation's mining industries. NMA works with Congress and federal and state regulatory officials to provide information and analyses on public policies of concern to its membership, and to promote policies and practices that foster the efficient and environmentally sound development and use of the country's mineral resources.

CURC is an industry advocacy group organized to promote research, development, demonstration and widespread deployment of technologies that will support continued and long-term use of coal. CURC's mission is to educate and advocate for coal-related technology development and use that will continue cost-effective and environmentally acceptable means by which America's most abundant fossil fuel resource can be used to provide low-cost energy and coal-derived products for our economy as well as worldwide. CURC's members include electric utilities, coal production companies, universities, research organizations, trade associations, state mineral resources agencies and manufacturers of equipment.

Many members of EEI, ACCCE, NMA and CURC are actively involved in the research, development, demonstration and deployment of technologies to capture CO_2 from electricity production and other industrial processes and inject it into geologic formations for long-term storage or ER, activities covered by the Draft Guidance. While not ER operators, the members of EEI, ACCCE, NMA and CURC have an interest in the regulatory structures addressing both ER and GS of CO_2 as they affect the ability of coal-based electric generating units (EGUs) to supply captured CO_2 either for ER or GS to comply with EPA regulations addressing greenhouse gas (GHG) emissions. In particular, our collective members are concerned about how the Draft Guidance may affect compliance with EPA's recently proposed CO_2 emissions standards for new fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle

(IGCC) units under Clean Air Act (CAA) section 111(b). *See Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, 79 *Fed. Reg.* 1430 (Jan. 8, 2014), *correction published* 79 *Fed. Reg.* 4439 (Jan. 28, 2014) (Proposed CO_2 Standards).

The Proposed CO_2 Standard for new fossil fuel-fired steam utility generating and IGCC units could only be achieved through the use carbon capture and storage (CCS). EPA explicitly recognizes that—and, indeed, relies on—the ability of EGUs to use ER as a storage option to facilitate compliance with the Proposed CO_2 Standards because selling captured CO_2 to ER operators could offset a fraction of the costs of installing capture on an EGU.

CCS could be a critical element in the full portfolio of technologies and measures needed to reduce CO_2 emissions from electricity generation and other industrial process, not only from the power sector, but also from other industrial processes. The Commenters disagree with EPA that CCS has been adequately demonstrated, such that it can be integrated with commercial-scale electricity generation at this time. The issue of adequate demonstration will be addressed in comments filed in response to the Proposed CO_2 Standards.[1] However, given the potential for CCS to contribute to GHG emissions reductions from the power sector in the future, the Commenters support the development of clear, defensible and appropriately tailored regulatory regimes that will facilitate development of and investment in CCS technology and demonstration projects while

[1] Commenters all intend to file separate comments in Docket No. EPA-HQ-OAR-2013-0495 in response to the Proposed CO_2 Standards.

protecting against potential environmental risks. Accordingly, while the Draft Guidance should be aimed at ensuring that ER operations do not endanger USDW, it should do so in a way that does not create unnecessary barriers to selling captured CO_2 to ER operators.

Comments

As EEI has noted in comments on previous UIC guidance documents, the issuance of guidance in piecemeal fashion makes it challenging for utilities fully to understand the UIC Class VI program. EPA already has finalized guidance documents on the following six topics: 1) Financial Responsibility; 2) Well Construction; 3) Project Plan Development; 4) Well Testing & Monitoring; 5) Well Site Characterization; and 6) Area of Review Evaluation & Corrective Action. The comment period on the following four guidance documents has closed: 1) Well Plugging, Post-Injection Site Care, and Site Closure; 2) Recordkeeping, Reporting and Data Management for Owners/Operators; 3) Recordkeeping, Reporting and Data Management for Permitting Authorities; and 4) Primacy Application and Implementation Manual. The Agency indicates that the following additional draft guidance document will be released for comment in the future: Injection Depth Waivers. Along with this Draft Guidance, that makes a total of 12 guidance documents that are in process or already have been finalized. All of these documents are related; indeed, the ones issued to date are replete with cross-references to one another. Accordingly, these comments are necessarily preliminary and may be subject to later modification as additional guidance is issued and finalized.

In the ongoing development of the UIC Class VI program, EPA should continue to take into account the experience of the Commenters' member companies with siting, permitting, operating and monitoring CCS projects. Since EPA published the final Class VI rule on December 10, 2010, 75 *Fed. Reg.* 77230, several projects have gleaned substantial experience with CCS project permitting, and at least one—American Electric Power's West Virginia-based Mountaineer demonstration project—successfully ceased CO_2 injections and is now in monitoring status. Another—Southern Company's Kemper County Energy Facility—is poised to commence commercial operations by the end of 2014. While these and other projects were not (and will not be) conducted under Class VI per se because they were permitted at a time when the Agency was still allowing research, development and demonstration injections to be conducted under Class V, they nonetheless should provide the type of "adaptive" data and experience that underpins the Class VI program:

> EPA agrees with commenters who supported an <u>adaptive approach</u> to the UIC rulemaking for GS … EPA also believes that an <u>adaptive approach</u> enables the Agency to make changes to the program as necessary to incorporate new research, data, and information about GS (e.g., modeling and well construction). This new information may increase protectiveness, streamline implementation, reduce costs, or <u>otherwise inform the requirements for GS injection of CO_2</u>. <u>The Agency plans, every six years, to review the rulemaking and data on GS projects to determine whether the appropriate amount and types of documentation are being collected and to determine if modifications to the Class VI UIC requirements are appropriate or necessary</u>. This time period is consistent with the periodic review of National Primary Drinking Water Standards under Section 1412 of [the Safe Drinking Water Act].

See id. at 77241 (emphasis added). When the time comes for EPA to commence a mid-course review of the UIC Class VI rule, the Commenters and their members would be pleased to participate in that process.

It is critically important for EPA to hew to its "adaptive approach" in implementing the Class VI program now that CCS may play a role in CAA regulatory programs. EPA's Proposed CO_2 Standards would establish emissions standards for fossil fuel-fired steam utility generating and IGCC units based on partial CCS (less than 90 percent capture) as the best system of emission reduction within the meaning of CAA section 111. *See* 79 *Fed. Reg.* at 1433.

CCS also is required to be evaluated as a Best Available Control Technology (BACT) under the CAA's Prevention of Significant Deterioration (PSD) major source permitting program. Numerous PSD permits already have assessed whether CCS is BACT in specific scenarios. To date, many of those assessments have focused on CO_2-enhanced oil recovery (CO_2-EOR), rather than injection into geologic formations under UIC Class VI. None has concluded that CO_2-EOR, let alone non-EOR CCS, is BACT for any electricity generating unit.

The Draft Guidance is particularly germane to the Proposed CO_2 Standards given EPA's reliance on CO_2-EOR as the CCS-based compliance pathway for fossil fuel-fired steam utility generating and IGCC units for the foreseeable future. Specifically, EPA's Proposed CO_2 Standards rely on the revenues that EGUs may earn from selling captured CO_2 to ER operators to reduce the cost of installing and operating capture equipment. EPA asserts that the costs of CCS are not unreasonable, particularly when CO_2-EOR revenue enhancements are considered. *See* 79 *Fed. Reg*. at 1478. The Commenters do not agree that CCS costs are reasonable at this time, regardless of whether there may be revenues associated with the sale of captured CO_2—and, indeed, disagree with EPA's determination that CCS is adequately demonstrated and can be deployed at commercial scale at EGUs at this time.[2] These concerns about the Proposed CO_2 Standards, which will be addressed in separate comments to EPA, are relevant in the context of UIC Class VI guidance documents as they serve to highlight the critical importance of CCS beyond the context of the UIC program, which is focused on the protection of USDW and not the reasonable development of CCS as a GHG emissions control technology.

The UIC program, therefore, must consider the broader implications of proposed Draft Guidance addressing the transition from Class II to Class VI wells. This is particularly important given that CCS projects that may move forward in the near future most likely will use ER instead of GS to store captured CO_2:[3]

> An assessment of the technical feasibility and availability of CCS indicates that nearly all of the coal-fired power plants that are currently under development are designed to use some type of CCS. In most cases, the projects will sell or use the captured CO_2 to generate additional revenue. These projects include the following [all of which are based on CO_2 offtake for EOR] … Southern Company's Kemper County Energy Facility … SaskPower's Boundary Dam CCS Project … Texas Clean Energy Project … [and] Hydrogen Energy California, LLC ….

79 *Fed. Reg.* at 1435.

[2] As noted, Commenters disagree with EPA as to whether CCS currently is adequately demonstrated such that it can be integrated with commercial-scale electricity production. Commenters also disagree with EPA about the likely future price that might be paid by ER operators for captured CO_2. This price is likely to be much less than the $20-40/ton range posited by the Agency. These issues will be addressed in comments on the Proposed CO_2 Standards filed in Docket No. EPA-HQ-OAR-2013-0495.

[3] If the FutureGen 2.0 project moves forward, it will not use ER, but GS, to store captured CO_2.

In the proposal, EPA further makes clear that, while EGUs may comply with the Proposed CO_2 standards by capturing CO_2 that is ultimately injected into and stored in a UIC Class II well, this arrangement is subject to other proposed terms and conditions related to monitoring: "The practical impact of our proposal would be that owners and operators of projects injecting CO_2 underground that are permitted under UIC Class II and that receive CO_2 captured from EGUs to meet the proposed performance standard will also be required to submit and receive approval of a [monitoring reporting and verification (MRV)] plan and report under subpart RR" of the Mandatory Greenhouse Gas Reporting Rule (MRR). *See id.* at 1483; *accord id.* at 1482 (discussing UIC Class II wells as part of the "Existing Regulatory Framework for CCS").

Consequently, it is critically important for EPA to provide regulatory certainty for CO_2-EOR and other ER owners and operators who intend to purchase and inject CO_2 from stationary sources whose GHG emissions are subject to CAA jurisdiction. Unfortunately, the Draft Guidance, while intending to provide such regulatory certainty, does just the opposite by casting doubts over: (1) when transition from UIC Class II to VI may be triggered; and (2) which regulator—federal or state, and within a state the UIC Class II or VI regulator, if different—is responsible for making that determination. ER operators have made it clear that they will not purchase captured CO_2 from EGUs if it would require a transition from UIC Class II to Class VI.[4] The Draft Guidance, therefore, could have the effect of eliminating CCS as a viable compliance option for EGUs subject to the

[4] ER operators have also stated that they will not accepted CO_2 captured by EGUs if it requires them to submit for approval MRV plans required under subpart RR of the MRR.

Proposed NSPS and could undermine any CAA programs that assume that CO_2-EOR operators will buy (and compensate EGUs) for captured CO_2.

Nothing in these comments should be interpreted as casting doubt on the ultimate need for deep saline storage. If the experts' predictions about society's continued reliance on fossil fuels for the decades to come are correct, coupled with ongoing policymaker judgments that GHG emissions are to be reduced, it seems likely that CCS's role will only grow in importance with time. And the widespread deployment of CCS ultimately is likely to require an increasing number of injections into non-EOR reservoirs because of the greater storage potential of deep saline formations and the geographic clustering of existing ER fields in only certain areas of the country.

However, for the foreseeable future and for reasons such as costs and the current status of climate policy—and as EPA itself seems to concede in the Proposed CO_2 Standards—it seems likely that CCS development is going to rely upon CO_2-EOR, in whole or in part. And because the EOR industry is not required to purchase the utility industry's CO_2, EPA must preserve CO_2-EOR as a regulatory pathway or risk delay in the broader implementation of CCS may be delayed, at minimum, if not its elimination as a climate policy solution.

Therefore, in light of the CAA stationary source regulatory programs in which CCS is playing a role, if the Draft Guidance does not meet the needs of the CO_2-EOR industry, it also fails to meet the needs of the electricity generators that may be required to rely on EOR operators to comply with their CAA obligations.

Accordingly, we encourage EPA to work with the CO_2-EOR industry to create a certain regulatory framework that ensures its ability to enter into long-term CO_2 offtake contracts with CAA-regulated EGUs that preserves existing CO_2-EOR commercial operations and provides EPA with the human health and environmental protections that it is seeking. The Commenters need to be a part of those discussions and looks forward to continuing to work with EPA on these critical issues.