June 25, 2012

Attn: Docket ID No. EPA-HQ-OAR-2011-0660
U.S. Environmental Protection Agency
EPA Docket Center
Mail Code: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Comments of Coal Utilization Research Council on EPA's Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (April 13, 2012), Docket ID No. EPA-HQ-OAR-2011-0660

The Coal Utilization Research Council (CURC) respectfully submits the following comments on the Environmental Protection Agency's (EPA) proposed New Source Performance Standards (NSPS) for carbon dioxide (CO_2) emissions from certain new fossil-fuel electric generating units (EGUs).[1] CURC was formed in 1997 and is a coalition of over 50 organizations that represent all aspects of the coal industry. A key part of CURC's mission is to support the use of coal by advocating for the development and employment of technologies that enable coal to be used in an economical, efficient and environmentally compatible manner.[2]

INTRODUCTION & OVERVIEW OF COMMENTS

On April 13, the Environmental Protection Agency (EPA or Agency) proposed a rule to set New Source Performance Standards (NSPS) that limit carbon dioxide (CO_2) emissions from new power plants burning fossil fuels. The proposed rule sets an emissions limit of 1,000 pounds of CO_2 per megawatt-hour of power generated. While a new natural gas combined cycle unit can likely meet this CO_2 emissions limit without additional emission controls, currently there is no system of controls that has been adequately demonstrated to achieve this standard for new coal fueled power plants.

The impact of this proposal is nothing less than to stop the development of new coal technology, and the deployment of coal-based capacity in the United States, as well as frustrate efforts to

[1] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012) (hereinafter referred to as the "proposed NSPS").
[2] *See* CURC website at www.coal.org.

commercialize carbon capture utilization and storage (CCUS)[3] technology. Such an outcome will seriously impact our Nation's ability to continue to benefit from a strong and growing economy based upon a diversity of cost-competitive and abundant energy sources and also jeopardize the use of a key domestic energy resource – coal – that historically has been the lowest cost, most abundant, and reliable energy source available to electricity consumers.

No power plant developer will commit to build a new coal fueled plant without assurance that a cost effective, commercially acceptable CCUS technology will be available within its first 10 years of operation to achieve CO_2 emissions compliance over the extended averaging period proposed in the rule. Even government-supported CCUS demonstration projects that are being planned or underway are placed at risk by the proposed rule albeit they may be classified as a transition project and therefore exempt. Compounding the lack of proven CO_2 capture technology are unresolved technical, legal, and regulatory issues concerning CO_2 storage options.

In addition, despite the need for further government assisted research, development, and demonstration of CCUS technologies, the Administration's fiscal year (FY) 2013 budget request for coal-related research and development has been reduced by $93 million (nearly one-quarter) from what Congress appropriated in FY 2012. In the absence of a legal and regulatory structure to address CO_2 storage options and requesting a diminished federal budget for CCUS technology development, the effective requirement for deployment of unproven CCUS technology is a wholly unrealistic expectation and does not represent a control technology that "has been adequately demonstrated" for establishing an NSPS. The Agency has concluded that no new coal fueled power generation will be built for a prolonged period of time and therefore no consequences will come of this proposed CO_2 rule. This conclusion must be challenged. If the proposed rule will have no effect at this time and it endangers the development of CCUS, the rule should be withdrawn.

The Coal Utilization Research Council (CURC) has significant concerns regarding the proposed rule. Our comments have been organized into the following three general categories and thereafter we have set forth recommendations that we ask the Agency to consider:

I. CONCERNS REGARDING THE USE OF A SINGLE SOURCE CATEGORY THAT WOULD APPLY TO ALL NEW FOSSIL FUEL-BASED ELECTRIC GENERATING UNITS (EGUs);
II. CONCERNS REGARDING THE INOPERABILITY OF THE PROPOSED ALTERNATIVE COMPLIANCE PLAN;
III. OTHER CONCERNS REGARDING VARIOUS SECTIONS OF THE PROPOSED RULE AS IT APPLIES TO THE APPLICATION OF CCS; and
IV. RECOMMENDED ALTERNATIVE APPROACH TO ADDRESSING GHG NSPS FOR NEW COAL-FUELED POWER GENERATION

[3] Wherever CCS (carbon capture and storage) or CCUS (carbon capture utilization and storage) are referenced in these comments they are used interchangeably and unless specifically noted otherwise both have reference to CCS as defined in the proposed rule.

Because the status and future development of carbon capture utilization and sequestration (CCUS) is central to the concerns we have about the proposed rule, and the assumption made in the proposed rule as to the commercial availability of CCUS, we have also attached (as Attachment A) to these comments a recently-completed CURC assessment that specifically addresses the technology readiness of carbon capture and storage (CCS). This assessment describes the three primary electricity generation options either currently available (Integrated Gasification Combined Cycle, advanced pulverized coal combustion including Supercritical and Ultra supercritical systems) or under active development (Oxycombustion) that would be the coal-based power generation options relied upon for the installation of CO_2 capture.

I. CONCERNS REGARDING THE USE OF A SINGLE SOURCE CATEGORY THAT WOULD APPLY TO ALL NEW FOSSIL FUEL-BASED ELECTRIC GENERATING UNITS (EGUs);

A fuel neutral standard, as proposed by the EPA sets a single standard for electric generating units using coal in steam boilers and natural gas in combined cycle units even though these fuels are different and use fundamentally different technologies to convert the fuel to useful energy. Absent the installation of commercially unproven CCUS, coal will not be able to achieve the performance standard set forth in the proposed rule.

A. GENERAL STATEMENT OF CONCERNS REGARDING THE USE OF A SINGLE SOURCE CATEGORY:

The methodology for setting the CO_2 NSPS is a significant departure from what EPA has previously used to establish performance standards for new fossil-fueled power plants. In past NSPS rulemakings for power plants, EPA has set different performance standards for each fuel (*e.g.*, coal, oil, natural gas) or the Agency has set a single emissions standard for all fuels based on the "best demonstrated technology" at all power plants, regardless of the fuels used. The single emissions standard is set so it can be met by the highest emitting fuel, if properly controlled through application of technology, and also by other fuel types with inherently lower emissions thereby establishing a fuel "neutral" standard.

The Agency has never set a single performance standard for all power plants based on emission rates achievable only by the lowest emitting fuel and technology. Yet that is what EPA is proposing in this rulemaking by establishing an emission rate that only natural gas combined cycle (NGCC) units have the potential to achieve. In the absence of proven CCUS, the rule is functionally equivalent to a requirement that NGCC is the sole available system of emission reduction. Therefore, this proposal is inconsistent with the Congressional direction that EPA's standards under Section 111 of the Clean Air Act cannot "be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction" in order to comply with an NSPS standard. 42 U.S.C. § 7411(b)(5). Further, EPA explicitly states in the proposal that the "proposed standard is based on the degree of emission limitation achievable through natural gas combined cycle generation." This statutory restraint on EPA's authority is particularly critical in matters of national energy policy, where fuel diversity has proven to be one of the key elements in assuring adequate, reliable and affordable electricity for residential consumers, industrial concerns, and manufacturers.

B. THE SINGLE SOURCE CATEGORY APPROACH IS NOT APPROPRIATE AND CCS IS NOT COMMERCIALLY AVAILABLE:

The proposed rule aggregates all types of fossil fuel-fired power plants into a proposed new category (the TTTT category) for purposes of regulating GHG emissions.[4] EPA then proposes an emission limit of 1000 lb. CO_2/MWh, "based on the demonstrated performance of natural gas combined cycle (NGCC) units."[5] No other means of compliance is identified as having met the statutory criteria for setting a standard of performance which is problematic in three respects. First, a standard is applied to coal-based power systems for which EPA has not identified a pathway to compliance which meets either pragmatic economic standards, or the statutory definition for a standard of performance. Indeed, as recently as December 2011, EPA declared the fundamentally sound legal arguments prohibiting such a "single rule" approach.[6] Second, the limitation has been set without a serious review of energy impacts. The EPA simply has assumed that currently low cost natural gas will remain so forever. Third, the reliance on a single compliance technology (NGCC power systems) is in clear violation of Section 111(b)(5) of the Clean Air Act.[7]

It is important to recognize that CCUS has not been applied at commercial scale to any power plant anywhere in the world. The Agency observes that technologies that support CO_2 capture, CO_2 compression, and pipeline transport, have already been proven and there are commercial integrated facilities storing and monitoring CO_2 in deep saline formations. None of these projects, however, are simultaneously producing electricity, capturing, cleaning, compressing, transporting, and storing large volumes of CO_2 (10-12,000 tons/day) on a continuous basis. Development of CCUS systems in an integrated fashion with a power generating facility under commercial-scale operating conditions is one of the key goals of the technology demonstrations and early adopter plants that the Department of Energy (DOE) is now supporting.

These CCS demonstration projects are currently underway, financially supported by significant government resources, and generally utilizing enhanced oil recovery (EOR) as a storage medium for CO_2 and as a revenue source to offset part of the cost of installing and operating CO_2 capture systems. The existence of these projects does not constitute evidence that CCS is currently a commercially available technology, nor that it will be commercially available in the near future. As discussed in more detail below, significant technical, economic, legal, and regulatory barriers

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[4] Standards of Performance for GHG Emissions for New Stationary Sources: Electric Utility Generating Units, Proposed Rule, EPA, 77FR22394, April 13, 2012.

[5] Ibid.

[6] Response to Public Comments on Rule Amendments Proposed May 3, 2011, EPA background document supporting the Standards of Performance Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA, December 2011. In support of the December 2011 criteria pollutant NSPS rule, EPA stated, "*basing these standards on [natural gas or distillate oil] would result in standards that are neither technically nor economically achievable for coal-fired EGUs. Basing the amended standards on the use of natural gas would preclude the development of new coal-fired EGUs since the standards would not be technically achievable…Therefore, basing the NSPS on [natural gas] emissions would not be achievable for coal-fired EGUs with any technology that EPA is aware of*."

[7] Section 111(b)(5) provides, "*nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance*."

must be addressed before CCS is commercially available for coal-based power generation. Certainly, the scope and magnitude of the barriers are significant enough that CCS fails to meet the statutory criteria for setting a standard of performance. EPA's inability to assert that CCS does not achieve these criteria ("*we are not proposing that CCS does or does not qualify as the 'best system of emission reduction' that 'has been adequately demonstrated'…*")[8], given the broad discretion of the 1973 Portland Cement decision (which accepts almost any projection of technology advances short of " 'crystal ball' inquiry")[9] speaks for itself.

In proposing to create a national standard that will have very adverse impacts upon the future use of coal, the EPA cannot simply assert "that CCS has been demonstrated to be technologically achievable", that "CCS is feasible and sufficiently available". The Agency references an August, 2010 report by the Interagency CCS Task Force (IATF) which noted that early CCS projects face economic challenges, first-of-a-kind technology risks and high cost, but the EPA concludes "there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions." The IATF also concluded that "CO_2 removal technologies are not ready for widespread implementation on coal-based power plants, primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application"[10] and "…. CCS technologies will not be widely deployed in the next two decades absent financial incentives that supplement projected carbon prices. In addition to the challenges associated with cost, these projects will need to meet regulatory requirements that are currently under development. Long-standing regulatory programs are being adapted to meet the circumstances of CCS, but limited experience and institutional capacity at the Federal and State level may hinder implementation of CCS-specific requirements. Key legal issues, such as long-term liability and property rights, also need resolution." The report further cited there are "other technical challenges associated with the application of these CO_2 capture technologies…" including, "high capture and compression auxiliary power loads, capture process energy integration with existing power system, impacts of flue gas contaminants (NO_x, SO_x, PM) on CO_2 capture systems, increased water consumption and cost effective O_2 supply for oxy-combustion systems."[11]

Given that coal plants emit approximately one ton (2,000 lb.) of CO_2 per MWh produced, a carbon capture level of about fifty percent (50%) will be required to achieve a 1,000 lb. CO_2/MWh standard. Relative to a baseline coal plant without capture, DOE estimates that the increase in cost of electricity (COE) at 50 percent carbon capture would be 43.3 percent,[12] This also represents a 43.3 % increase in costs over a NGCC[13] and demonstrates that this standard will result in coal being noncompetitive relative to a NGCC plant which requires no additional equipment.

[8] Op. Cit., Standards of Performance for GHG Emissions, 77FR22411, April 13, 2012.
[9] *Portland Cement Association v EPA*, 486 F.2d 375 (D.C. Cir.), 1973.
[10] Report of the Interagency Task Force on Carbon Capture and Storage, p.34, August 2010.
[11] Ibid., p.35.
[12] US DOE, Cost and Performance of PC and IGCC Plants for a range of Carbon Dioxide Capture, DOE/NETL 1011/1498, May 27, 2011
[13] US DOE, Cost and Performance Baseline for Fossil Energy Plants, Volume 1, Bituminous Coal and Natural Gas to Electricity, Revision 2, DOE/NETL-2010/1397 November 2010

Similarly, a recent Congressional Research Service (CRS) report[14] noted that there are numerous non-technical barriers to CCS that must be effectively resolved before the technology can be broadly deployed. While observing that recent Underground Injection Control rules may protect groundwater, CRS found that other key issues remain to be addressed. “Some of these include the long-term liability for injected CO_2, regulation of potential emissions to the atmosphere, legal issues if the CO_2 plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected CO_2 plume, and ownership of the subsurface reservoirs (also referred to as pore space).” Other recently issued reports have reached similar conclusions regarding the readiness and commercial availability of CCS.

In general, it is doubtful that performance guarantees can be obtained for CCS systems that employ saline storage, and there are unanswered questions regarding the accounting of CO_2 storage resulting from EOR. Such storage may be project-specific, given the general misalignment between power plant production of CO_2 and CO_2 needs over time by an EOR project. This misalignment argues for addressing CCS in a case-by-case Best Available Control Technology (BACT) context (as currently required by the Tailoring Rule) instead of a mandatory NSPS context. In any event, it leads to the conclusion that CCS fails to meet the statutory criteria required for relying on the technology as a basis for setting an NSPS.

CURC which includes manufacturers and suppliers of CCS related equipment and technologies as well as potential users of CCS technologies, submits that CCS has not been adequately demonstrated at any level that would suggest it is “technologically achievable, sufficiently available” and therefore ready to be deployed on a commercial basis

The preamble to the proposed CO_2-NSPS discusses technical feasibility of CCS technologies without regard to cost, commercial performance guarantees, the complexity of CO_2 storage, or associated legal issues and storage liabilities. The limited number of planned demonstration projects in the U.S. is falling, due in part to the weak economy, high costs, technical risks, and liability risks. In the time period since EPA proposed its rule on April 13, two other CCS-related projects have indicated that they will not move forward. These are the Taylorville project in Illinois, and the Good Spring IGCC project in Pennsylvania (both now moving forward as NGCC projects). It is CURC’s opinion that this proposed rule does nothing to incentivize, and may in fact discourage, the further development or deployment of CCS technologies. The economic, technology, legal, and regulatory risks are significant. Commercially available CCS for coal-based power generation will not be a viable control option until those risks have been appropriately addressed through multiple demonstrations and the experience gained through long term operation by early adopters. Stringent standards increase the technology risk of CCS and will further hinder demonstration and deployment; therefore it is unclear how EPA can then conclude that CCS technology will mature and costs will decline.

II. CONCERNS REGARDING THE INOPERABILITY OF THE PROPOSED ALTERNATIVE COMPLIANCE PLAN

The Agency has included in the proposed rule an “alternative compliance option” that would allow construction of a new coal fired plant without immediate inclusion or operation of CCS.

[14] Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. DOE, CRS, R42496, April 23, 2012.

EPA states that it believes the 30-year averaging option, in addition to potential government programs that could fund near-term CCS projects, "helps to alleviate any concerns that today's action could restrict new coal-fired construction."[15]

It is worthwhile to understand the Agency's logic behind the alternative compliance option.

A. THE PROPOSED RULE REQUIRES COAL-FUELED ELECTRIC GENERATING UNITS TO USE A TECHNOLOGY THAT HAS NOT BEEN ADEQUATELY DEMONSTRATED

First, by not designating CCS as a best system of emission reduction (BSER)[16] the Agency is not required to show that CCS is an "adequately demonstrated" system of emission reduction. In fact, EPA's inability to assert that CCS meets the statutory criteria for BSER demonstrates that it does not meet the required criteria for setting a standard of performance. EPA specifically states that "*we are not proposing that CCS does or does not qualify as the 'best system of emission reduction' that 'has been adequately demonstrated.'*".[17] It is telling that even though the Agency has broad discretion in projecting technology advances as part of an NSPS as a result of the 1973 Portland Cement decision (which accepts almost any projection of technology advances short of " 'crystal ball' inquiry")[18] the agency is still unwilling to posit CCS as a technology that can meet BSER. It is clear that CCS is currently, at least, not an available compliance option, and the Agency does not have the ability to determine that it will in fact be proven over the 10 years that sources have to install and begin operation of CCS under the alternative compliance pathway

Second, when designating BSER, the Agency is required to take into account "energy requirements" and, if CCS is not an available option, the test of "energy requirements" is jeopardized. The Agency argues[19] that the alternative compliance option allows for the use of coal with CCS either immediately or after 10 years through use of the alternative compliance option. If CCS is not currently available (which the Agency avoids saying by not designating CCS as BSER but which CURC absolutely argues is the case) then the fuel diversity test cannot be met because the standard of performance (coal only with CCS) is not achievable by coal. The Agency's argument, therefore, is circular because it wishes to include CCS as an alternative for coal but knows that CCS cannot meet the BSER requirements. The 30-year alternative compliance option is essential to a showing that fuel diversity is achieved because no new coal units can be built without CCS. While the BSER requirements do not themselves mandate fuel diversity, EPA is required to assess "energy requirements." In this proposed rule EPA moves away from its historical approach without justification by offering an alternative compliance approach that even it concedes cannot meet the BSER test.

To support the alternative compliance option, the Agency asserts, inter alia, that (1) the costs of CCS will decrease over time;[20] (2) there will be no more than a few CCS projects by 2020 and those plants can take advantage of available government-provided CCS funds;[21] and (3) several states have set standards that require CCS if coal plants are constructed in those states and,

[15] 77 Fed. Reg. at 22,399.
[16] 77 Fed. Reg. 22419 (April 13, 2012).
[17] Op. Cit., Standards of Performance for GHG Emissions, 77 Fed. Reg. 22411, (April 13, 2012).
[18] *Portland Cement Association v EPA*, 486 F.2d 375 (D.C. Cir.), 1973.
[19] 77 Fed. Reg. 22392, 22398 (April 13, 2012).
[20] 77 Fed. Reg. 22395 (April 13, 2012).
[21] 77 Fed. Reg. 22395 (April 13, 2012).

therefore, only CCS can be used in those states.[22] The alternative compliance option is simply a mechanism to increase the time period during which CCS technology might be demonstrated and costs of CCS might be reduced. Citing state requirements for CCS is irrelevant to the justification for the rule because the EPA must write a rule that can be complied with in all 50 states.

In proposing the rule, EPA applies models[23] to argue that because of low natural gas prices and other market conditions, almost no coal capacity (only 2 GW with CCS) will be built until 2020.[24] Arguing that little coal will be used between now and 2020, however, merely lessens the perceived burden of the proposed rule and permits the Agency to make the argument that few CCS projects will be required and those projects that are built will likely be the recipients of federal assistance. This argument ignores the real question: Why is EPA proposing this requirement for coal now if the Agency is arguing it will have no effect?

There are high costs and technical risks currently associated with CCS. Therefore, it is probable that only those CCS projects that are awardees of federal government financial support will be pursued. The more reasonable inquiry, however, one that the Agency does not pursue, is whether any coal plants employing CCS would even be considered at this time but for the government support. Even if some or all of the demonstration projects are actually constructed and operate (an unlikely occurrence due to financial and technical hurdles) the subsequent cost of CCS without further government subsidy will not decrease sufficiently to enable coal with CCS to compete for market share with low cost abundant natural gas. By prohibiting the use of coal without CCS, demand for electricity would be met with natural gas or other cost competitive available options, but not coal with CCS, which will remain significantly more expensive. Currently, no additional government financial assistance is available for CCS because the available programs have all been committed. In addition, the current technology challenges of capturing and storing CO_2 remain too great for subsequent CCS equipped coal plants to be built and operate.

In short, the proposed "alternative compliance plan" with 30-year averaging for CCS is predicated on completely unrealistic assumptions. Businesses would need to invest several billion dollars in power plants betting that after ten years of operation, or sooner, commercial CCS technology will be available for retrofit installation and operation. No power plant developer will commit to build a new coal fueled plant without assurance that a cost-effective CCS technology will be available within its first 10 years of operation to achieve CO_2 emissions compliance over the extended 30-year averaging period proposed in the rule.

The Agency's further assumption that within ten years coal-fueled plants equipped with CCS technology could achieve an emission rate of 600 lbs CO_2 per MWh, far lower than the proposed standard of 1,000 lbs CO_2 per MWh, anticipates a technology breakthrough and

[22] 77 Fed. Reg. 22416 (April 13, 2012).

[23] EPA Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, at 5.1 (page 59).

[24] EPA Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, at 5-9 (page 67). "By 2020, EPA forecasts roughly 27 GW of new renewable capacity, 2 GW of coal with CCS, and 10 GW of new natural gas-fired capacity."

commercialization schedule that is unrealistic and beyond the pace of project development currently underway. To be commercialized on a large scale, CCS installation will also have to be cost competitive with other energy production options.

Compounding the lack of proven CO_2 capture technology are unresolved technical, legal, and regulatory issues concerning CO_2 storage options. EPA ignores these sizable hurdles in proposing its alternative compliance option. In the absence of a legal and regulatory structure to address CO_2 storage the requirement for deployment of unproven CCS technology is wholly unrealistic. Again, the Agency's conclusion that new coal fueled power generation will not be built for a prolonged period of time and therefore no consequences will come of this proposed CO_2 rule is incorrect.

Finally, the Agency's contention that this proposed rule is actually a technology driver for the adoption of CCS is wrong. The Agency argues that if coal is chosen to fuel a power plant and CCS is required by law it will drive development and adoption of the technology. This scenario might occur if the technology were commercially mature and other less costly fuel options were not available, however, neither of these circumstances exists. No utility, no business, and no regulator, will choose to permit a more expensive power generating option, when less expensive options, fullfilling the same generation and capacity requirements, exists. EIA projects no new coal builds and years of less expensive and abundant natural gas from shale resources. Further, if the coal market is severely limited or the necessary technologies are non-existent, and if the EIA forecasts no new coal builds for several decades, what is to keep utilities and equipment suppliers interested in CCS technology development? This proposed rule does not "drive" CCS technology development or deployment, it would actually "freeze" the technology because advocates for CCS stop advocating, technology innovators find other paths for innovation, and the U.S.will lose its current global leadership position in developing CCS while China and other countries continue a forward march towards greater coal use without serious regard to technologies to control CO_2, or alternatively, choose to develop the CCS technologies for sale around the world.

Even assuming, for the sake of argument, that few new coal plants will be built over the next one or two decades, and any coal use could be accommodated through the 30-year averaging compliance option, the Agency has not constructed a sustainable system because fuel diversity is achieved only because any modest use of coal can be met with CCS projects that are now receiving government support. When that government support no longer exists, it is not clear how the industry will move forward given the requirement for CCS. EPA assumes that the cost of CCS will decrease over time, yet the Agency cannot know how much or how quickly costs will come down and indeed does not undertake any analysis in this regard. EPA cannot base its compliance requirements on vague estimates of CCS expansion. EPA contradicts itself in the proposed rule when it assumes both that no new coal fired EGUs will be built and that CCS technology will continue to develop over the next ten years.With the current abundant supplies of low-priced natural gas, and no clear path to reducing the costs of CCS nor resolving storage issues, the Agency has offered a compliance option for coal that is completely unrealistic.

EPA argues on one hand that the 30-year compliance option evidences the reasonableness of its NGCC based BSER by allowing an alternative pathway for coal as CCS technology matures. But, EPA also argues it is not proposing that CCS itself is BSER, and therefore there is no need to show that CCS is "adequately demonstrated." How does the proposed rule meet the section 111(a)(1) requirement that the standard of performance takes into account "energy requirements" and be "adequately demonstrated"? By not designating CCS as BSER, the "adequately demonstrated" requirement is avoided. By asserting that coal will not be used to meet any energy requirements and what little might occur can be met with government subsidized CCS projects through use of the alternative compliance option, the energy requirements standard is met. Coal without CCS is abundant and cost competitive with natural gas, even at low natural gas prices, but this proposed rule eliminates this important option.

B. ELECTRIC GENERATORS WILL NOT COMMIT TO CONSTRUCTION OF A MULTI-BILLION DOLLAR PROJECT ASSUMING THAT CCS TECHNOLOGY WILL BE AVAILABLE AND ADAPTABLE IN YEAR ELEVEN OF A PROJECT'S LIFE, AND FINANCIAL MARKETS WILL NOT FUND SUCH PROJECTS

Under the "alternative compliance option" owners have the option to build a coal plant today and add an integrated CCS system in later years to meet a 30-year, 1000 lb. CO_2/MWh average emission rate.[25] First-generation CCS technologies, however, are just moving into the demonstration phase. DOE has a suite of CCS demonstrations projects that are in various stages of development, most of which are still in the engineering phase. If these projects move ahead at a reasonable pace, it will still be at least 3-5 years before they complete construction and another 3 years after that before these CCS projects will have operated long enough to determine their success or failure.

In addition, given the cost and technology risk associated with CO_2 capture, a small number of successful demonstration projects will not be sufficient to provide widespread acceptance of the technologies as proven. Any successful demonstration projects must be followed by a first round of early adopter CO_2 capture projects that will take at least 10 more years to develop, permit, procure, erect, and commission. Following start-up, the plants will then have to successfully operate for 3-5 years to prove the technologies are commercially viable. Only after several of these early adopter CCS projects are proven successful will CO_2 capture technologies gain widespread acceptance for commercial deployment. As can be seen, this reasonable technology development timeline will require many years before anyone can expect CCS to be commercially deployed.

Furthermore, challenges remain with permanent CO_2 storage. While CO_2 storage technology development is advancing, property rights and liabilities associated with permanent CO_2 storage remain to be addressed.

For an owner to choose to build a coal-fired facility today with the requirement to have an integrated CCS system implemented within the next 10 years, they would have to know today that CO_2 capture is a proven and cost-competitive technology and that CO_2 storage sites can be permitted and will be accepted by the public as safe. Given the technological, economic, and legal risks of integrating an expensive and untested technology to what is already a very costly power plant, owners will not build (and lenders will not finance) coal-fired electric generation projects under this proposed rule. Adoption of this rule as written will stop commercial

[25] 77 Fed Reg 22392, 22406 (April 13, 2012).

development of new coal-based electric generation. With the reality that no coal plants will be built, CCS technologies will have little incentive and little opportunity for continued development.

C. 1,800 LB. CO_2/MWH BASELINE IS NOT AN APPROPRIATE STANDARD UPON WHICH TO PREDICATE THE ALTERNATIVE COMPLIANCE OPTION FOR VARIOUS TYPES OF COAL PLANTS.

The EPA proposed an alternative compliance option whereby power plants would be limited to 1,800 lb. CO_2/MWh on a gross basis for the first 10 years of operation and then be required to install an integrated CCS system. It is not appropriate to apply this baseline to all ranks and types of coals, which differ in their pollution characteristics. The normal operation of power plants, including start-up and level of load operation, demonstrate that it is not possible, in all instances, to achieve the stringent standard EPA has proposed.

The EPA reviewed data from its Clean Air Markets Database and concluded that this annual standard is appropriate for all new coal-fired power plants, regardless of fuel type. Specifically, EPA states that this standard is achievable by a supercritical coal plant.[26] Advanced coal-based electric generation technologies have the potential to achieve this emission level for selected fuels and optimal operating conditions. However, coal-based power plants are not always steady-state operations. In practice, the performance of such units varies due to fuel characteristics, load cycles, site/ambient conditions, and equipment degradation, among other factors. These variations will make compliance with the proposed 1,800 lb. CO_2/MWh limit challenging and uncertain. These factors will create a risk profile that will effectively preclude consideration of coal as an option for future power generation because it will not be possible to guarantee compliance with the rule, even prior to the CCS requirement.

Table 1 shows the expected CO_2 emissions rates for selected U.S. fuels, ranging from bituminous coal to lignite, being combusted in modern pulverized coal ("PC") power plants operating at full load conditions. Natural gas is included for comparison. This table shows that the 1,800 lb. CO_2/MWh limit may be achievable *at full load conditions* for bituminous coals, barely achievable for subbituminous coals, and unattainable for lignite coals.

Table 1: Specific CO_2 Emissions Rates vs. Fuel Type at Full Load

Fuel	lb. CO_2/Mwh-gross
Texas Lignite	1827
North Dakota Lignite	1857
Wyoming Sub-Bit	1781
Illinois High Vol Bit	1698
Natural Gas	922

There are a number of other factors that impact plant heat rate and thus CO_2 emissions and such additional factors also must be taken into account. All of these factors make the proposed EPA standard much more difficult or impossible to achieve. Each of these factors is described below:

[26] 77 Fed Reg 22392, 22406 (April 13, 2012).

Partial Load Operation

The plant heat rate increases as the plant operating load is reduced, which corresponds to increases in the specific CO_2 emissions rate. Based on the performance of a specific modern commercial power plant, the heat rate increases 1% at 75% load and 6% at 50% load. The heat rate increases more dramatically at even lower loads, rising by almost 20% at 35% load. The heat rate has a great impact on the specific CO_2 emissions rate as a result of normal plant load variations. Coal-based power plants typically follow either a base load or cycling operation load profile, depending upon factors such as the plant's dispatch cost and grid requirements. These situations have quite different patterns of load variations and corresponding emissions rates, and the EPA has not taken this reality into account when setting the standard.

Base load Operation

All power plants have some load variation that will impact heat rate and CO_2 emissions rate. A typical PC base load plant may operate 60% of the time at 100% load and another 35% between 50-75% load. The average capacity factor would be about 85% and it would have an average heat rate typically about 1% higher than at 100% load. This variation alone would be sufficient to increase the specific CO_2 emissions rate from a PC plant firing Wyoming subbituminous coal from 1,781 to 1,799 lb. CO_2/MWh. This example highlights the limited compliance margin, if any, that is afforded by the 1,800 limit. In turn, it identifies the challenges and compliance risk that will be experienced over the life of the unit.

Cycling Operation

A typical PC cycling plant may operate 30% of the time at 100% load, another 55% between 50-75% load with the balance of operation at even lower loads. The average capacity factor would be about 70%, and it would have an average heat rate typically about 4-5% higher than at 100% load. A 5% heat rate increase from cycling operations would increase the specific CO_2 emission rate of the Illinois bituminous coal from 1,698 to 1,783 lb. CO_2/MWh – already getting very close to the 1,800 limit. Plant cycling is particularly significant as more plants are expected to cycle in the future as renewables increase their share of power generation.

Degradation Due To Plant Age

Power plants are designed to operate for many years, they are long life assets and many have cost effectively operated for 50 years and more. Normal expected wear and tear has a detrimental impact on a plant's heat rate. Looking solely at the steam turbine, a plant's heat rate could deteriorate by about 1% after 10 years of operation based on a steam turbine degradation curve known as the PTC6 curve.

Site Factors

Other factors can impact the design of an advanced coal-based power plant that can also have a negative impact on plant heat rate and thus the CO_2 emissions. For example, areas with limited water resources could require an air-cooled condenser rather than water cooling. Local water temperature can also have an impact on condenser operating pressure and heat rate.

Table 2 summarizes the impact of an increase in plant heat rate due to the above factors on the specific CO_2 emissions rate for a state-of-the-art ultra-supercritical PC power plant. A plant that is required to cycle would likely have a heat rate 5% higher than its design 100%-load heat rate. In this scenario, a bituminous coal-fired unit, under ideal conditions, would achieve the standard with minimal compliance margin, while the lower rank fuels would exceed the 1,800 lb. CO_2/MWh rate. It is likely that the bituminous plant would also exceed this target after appropriately accounting for site specific factors, impacts of startup, shutdown, and age deterioration. The cycling impact could be even more significant in the future as renewables assume a larger portion of the total power generation.

Table 2: Impact of Heat Rate Degradation on Specific CO_2 Emissions Rates

Heat Rate Increase (%)	0%	1%	2%	3%	4%	5%
	Specific CO2 Emissions					
Fuel Type	lb CO2/MWh-gross					
Texas Lignite	1827	1845	1863	1881	1900	1918
North Dakota Lignite	1857	1875	1894	1912	1931	1949
Wyoming Sub-Bit	1781	1799	1817	1835	1852	1870
Illinios High Vol Bit	1698	1715	1732	1749	1766	1783
NGCC	922	931	940	949	958	968

EPA Clean Air Markets Database

The EPA cited data from their Clean Air Markets Database to support their proposed 1,800 lb. CO_2/MWh limit. A review of the database showed that the bulk of the reporting plants exceeded it by a wide margin. After removing obvious outliers, the average specific CO_2 emissions rate from 230 plants was 1,916 lb. CO_2/MWh.

Table 3 shows a comparison of the four supercritical PC plants that the EPA cited in justifying the proposed 1,800 lb. CO_2/MWh target. The Agency stated that it considered these four plants as representative of a new coal-fired power plant. An independent check was made of this data by reviewing the hourly emissions reported in the Energy Velocity database. The results show similar CO_2 emission rates. It was apparent, however, that the capacity factor for each of these four plants was high. All four units were clearly operating as base load plants, with capacity factors in the mid-80% range for three units. EPA should have taken into consideration that none of these units would have met the proposed limit if they were operated as typical cycling units.

Table 3: Comparison of EPA Clean Air Markets and Energy Velocity Databases

	Data from EPA Clean Air Markets Database			Data from Energy Velocity Database		
Facility	Time Period	Primary Fuel	Max 12 month CO2 Emissions Rate - lb CO2/MWhr-gr	Time Period	Max 12 month CO2 Emissions Rate (lb CO2/MWhr-gr)	Average Capacity Factor (%)
Bull Run 1	2009-2010	Bituminous	1740	2009-2011	1753	86
Weston 4	2008-2010	Subbituminous	1740	2007-2011	1740	84
WH Zimmer 1	2005-2009	Bituminous	1760	2005-2009	1721	86
Walter Scott Jr 4	2007-2010	Subbituminous	1800	2005-2011	1815	77

EPA states that marginal units can still achieve the proposed standard by applying costly improvements, such as double reheat, coal drying (for lignite coals), or co-firing with natural gas. These modifications all add additional equipment at the expense of increased capital/operating cost and potentially decreased availability. EPA should not be requiring the installation of this type of equipment in order to achieve their target. These requirements would be added expense and makes coal-fired technology less competitive.

Next, the long-term limit should be designed so that applicable limits during the non-CCS phase of operations (which in the proposed rule would be ten years) accurately reflect the best demonstrated emission rate achieved by operating advanced coal technologies. The current assumed rate of 1,800 lb. CO_2/MWh should be revisited because it is not consistently possible for even very efficient new coal plants to meet the standard under varying conditions

D. Many of the planned CCS demonstrations will not be completed

A consensus conclusion in recent reports of the IATF on CCS chaired by EPA and DOE, the 2009 National Research Council Report titled "America's Energy Future: Technology and Transformation", and the National Coal Council report "Low-Carbon Coal: Meeting U.S. Energy, Employment And CO_2 Emission Goals With 21st Century Technologies" (December 2009), was that five to ten large-scale integrated CCS projects will need to be underway by 2015 for the technology to be commercially ready by 2020. In this context, "large-scale" is considered to mean greater than 1 million tonnes per year of CO_2 captured and either stored in geological formations or put to beneficial use (i.e. EOR). The current DOE research, development, and demonstration program for CCS, which is the most robust and ambitious in the world, is comprised of the Clean Coal Power Initiative (CCPI), the Industrial CCS program (ICCS), the FutureGen 2.0 project, and the Regional Carbon Sequestration Program (RCSP), as well as certain tax credit and loan guarantee programs. These programs have announced support for ten major integrated CCS or CCUS demonstration projects, six of which are coal- or petcoke-based power generation projects, only one of which has broken ground for construction, and only one of which is coal-based power generation with non-EOR CO_2 sequestration.

A recent report by the Congressional Research Service titled "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" (April 2012), recognizes that "…the CCS RD&D program in 2012 is just now embarking on commercial-scale demonstration projects for CO_2 capture, injection, and storage. The success of these demonstration projects will likely bear heavily on the future outlook for widespread deployment of CCS technologies…" That report goes on to describe in great detail the difficulties experienced by the FutureGen project as it attempted to move forward, and concludes that "if all the CCS demonstration projects encounter similar changes in scope, design, location, and cost as FutureGen, the chances of meeting goals laid out in the DOE 2010 Strategic Plan—namely, to bring at least five commercial-scale CCS demonstration projects online by 2016—may be in jeopardy."

The National Coal Council also evaluated the adequacy of the CCS demonstrations programs in collectively achieving the advancements needed for CCS technology on coal-based generation to be commercially ready by 2020, and reported in "Expedited CCS Development: Challenges & Opportunities" (March 2011) that "the current DOE CCS development program, although robust by world standards, has not moved fast enough and is not on pace to have the level of impact hoped for by 2020. At the current rate, CCS technologies will continue to be in an early development stage by 2020." Moreover, it stated that "on the basis of the past experience with the DOE's large-scale demonstration programs, it is unlikely that more than two or three projects of the existing suite will initiate the injection of 1 million tonnes of CO_2 per year into geologic formations (excluding EOR) by 2020." Thus, it appears likely that few of these CCS demonstration projects will proceed to completion and that the demonstration program will be insufficient to allow CCS technology to be commercially ready by the early 2020s. In light of this information, it is doubtful that any power generator would proceed with committing $2 billion or more in a new coal-fired power plant under EPA's proposed alternative compliance plan for at least the next ten years. Thus, the rule's Alternative Compliance option is not a real alternative at all.

III. OTHER CONCERNS REGARDING THE APPLICATION OF THE PROPOSED RULES TO CCUS

In addition to the central issues addressed above, EPA's proposed rule contains several additional technology-related concerns. These include the rule's creation of barriers to CCS development, the inadequacy of enforcement provisions, EPA's failure to recognize the consequences of the precedents which would be established by promulgation of the proposed rule, EPA's superficial assessment of energy and economic impacts (both of which are statutory determinants of the standard itself), and issues related to modified and reconstructed sources.

TECHNOLOGY BARRIERS. As an entity constituted primarily to advance improved coal utilization technologies, CURC is particularly sensitive to regulatory actions which create additional barriers to new coal-related technologies. CURC believes that adoption of the proposed rule would create, not mitigate, such barriers to CCS technology. We offer the following concerns for consideration:

1. A hard regulatory requirement ties regulators' hands when working with developers of an innovative technology like CCUS.
2. Adding additional compliance and enforcement risks to already significant technical and financial risk will effectively eliminate new coal builds, and with it the economic motivation of a future market that technology developers need to justify their investment.
3. An effective mandate to apply integrated CCS systems will eliminate the ability of the power facility to receive full market value for CO_2 sold for EOR purposes, as EOR project developers correctly assess the disadvantaged position of power plant operators who must "get rid of" their CO_2 under a mandatory rule. While significant payments for

CO_2 to be used in EOR may be insufficient to make CCUS projects economically competitive at current costs of capture, failure to realize this significant revenue stream for CO_2 will almost certainly prohibit coal-based projects in the near and medium term, even where additional subsidies or economic incentives are provided.

4. A 1000 lb. CO_2/MWh limit effectively moves the case-by-case negotiations for determining New Source Review BACT to a more restrictive zone.

CURC believes that the existing New Source Review requirement for case-by-case BACT determinations has established a reasoned weighting of factors which might lead to a choice to require CCS on a new coal-fueled electric generating unit when the technology is commercially and technically viable at utility scale, and maintains appropriate pressure for technology developers to provide resources for CCS development.

INADEQUATE ENFORCEMENT PROVISIONS. The proposed rule does not provide an adequate basis for determining compliance if a source chose to put on an integrated CCS system. The rule is focused solely on stack emission rates, and basic compliance requirements but procedures for meeting the emission limit by using CCS or CCUS are not discussed in the preamble or included in the Part 60 regulatory language. Some have suggested, for example, that oil produced by EOR does not displace traditional oil production, and the credit for injected CO_2 should be diminished by the CO_2 which would be emitted if the produced oil were burned.[27] Such an approach would effectively terminate interest in EOR as a storage mechanism for CO_2. It is impossible to understand the ultimate cost, environmental impact, energy impact, or practicality of CCS or CCUS if the full regulatory requirements are not defined as part of the rule.

HARMFUL PRECEDENTS. Promulgation of the proposed rule would create precedents which would have dramatic adverse economic and energy impacts. The most significant of these precedents is probably the proposal to reverse EPA's historic practices and regulate all fossil fueled power plants by a standard achievable only by the lowest emitting fuels and technology. This precedent should not be applied to the upcoming Section 111(d) regulation of existing power plants. The inescapable result will be the wholesale closure of much or all of the existing coal-fired power plants. Since these existing units produce power for 2-3 ¢/kWh, and any replacement power system would produce power costing at least 7-10 ¢/kWh, the economic impact on the nation would be dramatic as the macro-economic effects of higher electricity costs percolate through the economy, destroying consumer purchasing power and adversely impacting the competitiveness of U.S. manufactured goods in international markets. Similarly, once EPA has established the principle that it has the authority to "redefine" a proposed new source to use a fundamentally different fuel and technology than included in the permit request, permitting authorities will be free to specify that a proposed new fossil-fueled power plant should instead be a nuclear power plant or a renewable energy power plant. Some might argue that EPA has already assumed such authority, citing decisions by the EPA Environmental Appeals Board,[28]

[27] See for example, Life Cycle Inventory of CO2 in an Enhanced Oil Recovery System, P. Jaramillo, et. al., Carnegie Mellon University, *Environmental Science & Technology*, 2009, Vol. 43, No.21, 8027-8032.

[28] See Order Denying Review In Part and Remanding In Part, USEPA Environmental Appeals Board, PSD Appeal No. 08-02, February 18, 2009.
http://yosemite.epa.gov/oa/eab_web_docket.nsf/Filings%20By%20Appeal%20Number/06DBEC31EBFD8C3E852575620052318B/$File/Denying%20and%20Remanding...79.pdf In this decision, EPA remanded a permit by the Michigan DEQ for a new heating plant at Northern Michigan University. The proposed permit for a multiple fuel

but the proposed rule would greatly expand EPA's authority to dictate fuel choice and power plant design. CURC believes that there is no statutory authority for such regulatory measures.

INADEQUATE ENERGY AND ECONOMIC ANALYSIS. Using what can appropriately be described as "heroic assumptions", EPA has concluded that the rule will have no economic, energy, or environmental impact. Many of these assumptions are embedded in the model used by U.S. DOE/EIA to project future electricity markets in both the AEO-2011 (cited by EPA), and the more recent AEO-2012. However, EIA acknowledges that it considers only current regulatory requirements. Moreover, EIA's expectations for future conditions change from year to year and in the past have changed a great deal regarding natural gas price expectations – which are primarily responsible for EIA's recent projections regarding limited future coal builds. Government estimates of domestic natural gas reserves have fluctuated wildly over the past two years, as the implications of new extraction technologies have been considered by EIA and the USGS. For example, the USGS increased its estimate of Marcellus shale resources by 40 fold in August 2011,[29] but this estimate remained about one-fifth the magnitude of EIA's estimate in the AEO-2011. It remains unclear how much of whatever estimate of "technically recoverable" resources will move into the "proven reserve" category that implies a fuel is economically and environmentally practical for commercial use. Future EPA regulations on natural gas production, changing natural gas markets such as increasing LNG exports, competition for natural gas by industrial and chemical applications, and volatility in oil prices (which impact demand for coproduced gas and natural gas liquids) are but a few of the factors which could significantly change the future domestic supply of dry natural gas and natural gas prices.

Additionally, NEMS, the EIA model used to project future power demand, has not yet been programmed to address the complex issues associated with CO_2 EOR markets. To the extent that the EPA rule discourages development of CCS technology or CCUS employing EOR (as discussed above), the economic impact of the rule could be hundreds of billions of dollars over the next several decades.

EPA's decision to evaluate economic impacts over an 8 year period is inappropriate for evaluating a far-reaching technology like CCS. By taking a short term perspective based on a weak technical foundation, the proposed rule could fail to identify unintended and potentially profound long-term economic consequences which eliminate coal as a domestic energy resource. Furthermore, as discussed above, the rule is more likely to have an adverse, not beneficial, effect on the rate of development of technology that will ultimately be necessary to slow, halt, and finally reduce emissions of anthropogenic CO_2. The US is the global leader in CCS development and taking the US out-of-play will effectively defer or even halt CCS and CCUS development.

As discussed above, the Section 111(b) rule tends to define the outer limits of reasonable action, as well as reasonable approaches for the upcoming Section 111(d) rule. Extending the principles proposed in this rule to existing sources will cause major economic disruptions.

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circulating fluidized bed boiler, which was designed to use coal as a primary fuel, was rejected by EPA because it did not adequately assess using wood as the source's primary fuel in order to reduce sulfur dioxide emissions.

[29] Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011, US Geological Survey, US Department of Interior, Fact Sheet 2011-3092, August 2011.

<u>MODIFIED AND RECONSTRUCTED SOURCE ISSUES</u>. CURC agrees with EPA that the proposed rule should not apply to modified sources. We believe, however, that EPA has offered an incomplete justification for this policy. The reasoning EPA offered for transition sources – that the units have already been configured for a non-CO_2 limiting regulatory environment and would experience much higher costs for retrofitting – applies even more so to existing sources. Additionally, retrofitting CCS may be wholly impractical for many facilities, due to lack of space or lack of sufficient cooling water for the additional equipment introduced by carbon capture technologies. A third factor favoring exclusion of modifications from the rule would be that such a policy would be environmentally counterproductive, discouraging possible efficiency improvements which could reduce CO_2 emissions.

CURC also agrees with EPA's decision to exclude reconstructed facilities from the proposed rule. However we are concerned that an existing facility which elected to retrofit CCS, potentially to enter EOR markets for example, might become a "reconstructed" facility for purposes of non-CO_2 NSPS, given the high cost of CCS technology. Retrofits are a key platform for technology demonstration and validation. EPA rules state that: *"'Reconstruction' means the replacement of components of an existing facility to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part."*[30] Reconstructed plants are subject to the NSPS, MATS, and potentially other requirements, even if the reconstructed source has no increase in regulated emissions. Absent an exclusion of reconstructed sources related to CCS, the addition of carbon capture could trigger re-permitting under these rules. Although the proposed rule would exclude reconstructed sources from application of the CO_2-NSPS, it does nothing to insulate projects which retrofit CCS from reconstruction provisions applicable to other air emissions. CURC encourages EPA to consider ways to eliminate such barriers to the voluntary use of carbon capture.

<u>COMBINED HEAT AND POWER.</u> New combined heat and power (CHP) facilities would be subject to the same CO_2 performance standard as other covered EGUs. Because CHP facilities generate useful thermal energy as well as electrical output the Agency proposes to adjust the manner of calculating the CO_2 emissions rate from these facilities. The proposed rule would provide that a CHP unit divide its total CO_2 emissions by the sum of its gross electrical energy output and its useful thermal energy output to determine compliance with the proposed standard. In addition, a CHP facility whose useful thermal output represents at least 20% of its total energy output would increase its electrical output by 5% to reflect avoided transmission and distribution losses. Both adjustments would increase the apparent energy output of a CHP facility, thereby lowering the CO_2 emissions rate per unit of output.

EPA should exempt combined heat and power (CHP) sources whose useful thermal output is at least 20% of their total output, on the basis that CHP is a highly desirable configuration for both reduced emissions and conservation of fuel, and the exemption will promote its adoption.

[30] 40CFR60.15(b).

IV. RECOMMENDED ALTERNATIVE APPROACH TO ADDRESSING GHG NSPS FOR NEW COAL-FUELED POWER GENERATION.

A. EPA MUST ADOPT FUEL SPECIFIC EMISSION LIMITS FOR NEW SOURCE PERFORMANCE STANDARDS.

EPA concludes that CCS is not an appropriate technology on which to base NSPS "best system of emission control" for natural gas power plants, and that requiring an efficiency limit that reflects a performance level achieved by the vast majority of NGCC units built between 2006 and 2010 is reasonable.[31] CURC is not commenting upon whether NGCC units are capable of meeting the proposed standard, rather it is the approach used by the Agency in determining a standard for natural gas which is an approach that would also be appropriate for coal-based power plants. This can only be achieved by establishing a separate coal standard that reflects the "best system of emission control" for coal. Further, an appropriate performance standard for coal-fired units must be based on data from operating coal-based generation units, not on a design specifications or expected performance levels. It is imperative also that such a performance standard account for the use of different coal types, different combustion technologies (that is, pulverized coal boilers or fluidized bed boilers), and differences in plant operating conditions (i.e., base load, load following, load cycling) all of which will impact average heat rate and CO_2 emissions rate. Finally, such a standard for coal must also accommodate startup/shutdown or these periods need to be excluded from compliance calculations.

Under Clean Air Act § 111,[32] the EPA, in establishing performance standards for new sources, must consider a standard which has been "achieved in practice."[33] In order to set standards, "the Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards."[34] Historically, the setting of standards has included utilizing different standards for fuels and technologies that have different characteristics. This process allows for various fuels to meet the highest possible pollution control levels, without summarily removing one type of fuel or technology from the marketplace because it cannot meet the standard which another fuel can meet.

Contrary to prior precedent, in the proposed GHG NSPS , the approach proposed by the Agency would combine NGCC units and coal steam boilers and require both to meet the same standard, a standard achievable only by a new NGCC unit .[35] This approach is contrary to EPA's practice

[31] NSPS Preamble, 77FR22414, April 13, 2012

[32] 42 USC § 7411(b).

[33] "When implementation and enforcement of any requirement of this chapter indicate that emission limitations and percent reductions beyond those required by the standards promulgated under this section are achieved in practice, the Administrator shall, when revising standards promulgated under this section, consider the emission limitations and percent reductions achieved in practice." 42 USC §7411(b).

[34] 42 USC §7411(b)(2).

[35] EPA states that it is "proposing to combine electric utility steam generating units (boilers and IGCC units, which are currently in the Da category) and combined cycle units that generate electricity for sale and meet certain size criteria (which are currently included in the KKKK category), into a new category for new sources (the TTTT category) for the purposes of GHG emissions." 77 Fed. Reg. 22394 (April 13, 2012). The standard proposed is 1,000 lb. Co2/MWh.

under the CAA, which has historically allowed for fuel diversity. In order to continue this practice and comply with the intent of the Clean Air Act, EPA should either create separate categories for different types of fuel and technology, or if it wishes to have one combined category for GHGs from base load EGUs, such as category TTTT in the proposed rule, it should subcategorize by fuel and boiler types to allow for an achievable standard for each fuel.

It is important for EPA to appropriately categorize fuels to determine achievable Best System of Emission Reduction (BSER) requirements. EPA should not have a system wherein coal and natural gas are combined into one category and the BSER standard is applied to all base load power sources, as the agency has done in this rule. The combination of source categories has historically been based on the characteristics of the fuel or the source, not the *use* of the source (e.g. base load power). Here EPA combines categories into one, TTTT, for all base load EGUs solely because EPA asserts that they perform the same function, not because of similar characteristics or pollution control procedures. Indeed only within the last several years has a large percentage of NGCC units operated as base load units. Prior to the period of low prices for natural gas such natural gas fired units operated as cycling plants and therefore did not perform the same function as base load coal-fueled power plants.

Instead of combining categories in this way, EPA should look to the best performing units with respect to different types of major coal usage and conversion, and define categories and subcategories around such different fuel types and sources. We strongly suggest that EPA consider the type of technology and the type of fuel and create categories and subcategories that reflect these differences and address their effects on achievability, in order to comport with the CAA and to maintain the goal of fuel diversity.

B. EPA MUST NOT RELY ON CCS AS A COMPLIANCE OPTION BECAUSE IT IS NOT COMMERCIALLY AVAILABLE.

In the proposed rule, EPA asserts that Carbon Capture and Sequestration (CCS) is commercially available and therefore is a reasonable control technique to be employed by coal-fired EGUs. However, the EPA is mistaken in its assessment concerning the level of technology development that has occurred, as well as the current state of the CCS market.

There are no commercial-scale electricity generation facilities fully integrated with CCS operating anywhere in the world. Even the DOE, in its CCS Roadmap, finds that the technology will be ready to "begin commercial deployment in 2030."[36] Studies, including a report by the CRS, have noted that CCS is still in the demonstration phase and that there are no full scale commercial (non-subsidized) applications of CCS to date.[37] Indeed, in 2012 DOE's CCS RD&D program is just now embarking on commercial-scale demonstration projects for CO_2 capture, injection, and storage. In short, an integrated CCS system on a coal fueled electric generating

[36] Department of Energy, Carbon Capture and Storage Roadmap, found at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

[37] Carbon Capture: A Technology Assessment, CRS Report, Peter Folger, July 19, 2010. http://www.cnie.org/NLE/CRSreports/10Aug/R41325.pdf, which notes, "At present, there are still no full-scale applications of CO2 capture on a coal-fired or gas-fired power plant (i.e., a scale of several hundred megawatts of plant capacity)."

unit has simply not been commercially tested and is not available, and therefore should not be viewed as a compliance option by EPA.

Indeed, even the current slowly-progressing CCS demonstration projects are not indicative of industry readiness because they are heavily dependent on federally subsidized financing incentives and have unique characteristics, like proximity to a site for enhanced oil recovery (EOR). One of the rationales that EPA provides for setting a standard that will require the installation of CCS is that there are a number of CCS demonstration projects that are currently slated to be completed by 2016. Planning to have a CCS demonstration does not in itself make CCS commercially available. Whether or not these projects are actually completed by that time, they have many factors that make them non-replicable, including large subsidies and very specific geographic placement, and therefore such projects should not be used to suggest that the industry as a whole is ready to employ this technology.

Given that CCS is not commercially available for coal-based generation, CURC recommends that the agency undertake a thorough review of currently operating coal-fueled electricity generating units and thereafter establish reasonable performance standards based upon this "best in class" examination. It is important to recognize that size of the power generation facility, type of coal conversion technology applied (e.g. pulverized coal versus circulating fluidized bed (CFBs)), and ranks and characteristics of specific coals need to be considered in setting performance standards for new coal fueled power plants. The agency is required by statute to periodically review and revise the NSPS requirements. Under the Clean Air Act, "the Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[38] It is premature for the EPA to include CCS technology as a compliance option. The EPA should wait until the next round of changes to the NSPS to re-evaluate the status of CCS and only if technically and economically available integrate CCS into the compliance system. By that time it is more likely that the technology will have been demonstrated and may then be commercially available thereby providing real technology application upon which to make a decision requiring widespread application.

C. EPA SHOULD RELY ON THE EXISTING PSD PERMITTING PROCESS AND CASE-BY-CASE BACT TO ASSESS GHGS FROM NEW COAL PLANTS.

Instead of creating an NSPS with an unachievable standard and a compliance option based on unproven technology, the EPA should rely on the existing Prevention of Significant Deterioration (PSD) permitting structure and individual BACT determinations to address GHGs from new coal plant development. This case-by-case approach is better able to include a number of factors that are important to the development of the CCS industry without requiring applications that are not commercially available or possible.

For instance, in the near-term to medium-term some new coal plants may be able to employ CCS if they are heavily subsidized and located near EOR opportunities. These plants have unique characteristics that would make it reasonable to include CCS in their BACT determinations, and the process of undertaking a PSD permit with such requirements will assist the agency in determining the factors that do make CCS feasible in particular instances.

[38] 42 USC §7411(b)(1)(B).

The case-by-case process will also allow for new coal plant development in areas of the country requiring additional sources of base load power but where capturing CO_2 and sequestering into deep geologic formations or using it for EOR is not feasible. Such a case by case approach would allow flexibility for state regulators to potentially permit the use of coal based upon the application of commercially available technology. It is imminently more reasonable to require that these determinations be made on a case-by-case basis in which CCS may be selectively included in sites where it is possible. CCS for all new coal-fueled developments should not be required until it is commercially available on coal-fueled electric generation units and at a non-prohibitive cost.

CONCLUSION:

The CURC respectfully requests that the EPA make significant revisions to the proposed rule. Coal resources in the United States are vast, accessible and proven to be a dependable, cost competitive source of fuel for electricity generation. By its own finding the Agency has concluded that only a very modest amount of new coal plant construction is contemplated for several years into the future. To avoid jeopardizing progress being made in the development of CCS technologies the Agency should table or significantly alter these proposed rules as suggested in these comments. Such action will provide industry, now partnering with government, the time needed to mature CCS technologies and thereby insure commercial availability for use in the electricity generation sector.

Carbon Capture and Storage: Technology Status, Cost, Deployment and Timing for Electric Power Generation

Summary

The U.S. enjoys significant economic and energy security benefits from the use of coal. Coal is used primarily for the production of electricity, but can also be converted to transportation fuels, synthetic natural gas or serve as a source of feedstock for the chemical industry. Concerns about climate change have led to requirements to reduce greenhouse gas emissions (i.e. carbon dioxide, CO_2) from coal based processes. To maintain the ability for the U.S. to continue to use this abundant and low cost resource effective and affordable carbon capture and storage (CCS) technologies must be developed and brought to commercial deployment. This paper l focuses on CCS technologies that can be integrated with coal-based power plants.

Much progress has been made in the development of technologies required to capture, compress, transport and utilize or store CO_2. Many of the components required to enable CCS have already been developed and employed in other industries. However, these technologies have not been integrated into electric generating facilities at any scale nor has the application of CCS been demonstrated as cost-effective. Further, the use of CCS technology requires a substantial amount of energy from the power plant itself in order to operate. This use of parasitic power adds to the cost of generation and the need for replacement electricity from other sources. A recent analysis conducted by CURC calculated that incorporating current CCS technology into a coal-based power plant could roughly double the cost of electricity from the facility.[39]

Progress has occurred in the storage of captured CO_2. For example, underground injection and storage (in saline formations) of CO_2 has been used at small scale for over 20 years in Alberta, Canada, and a few large scale operations on non-power applications also exist. The US Department of Energy (DOE) has implemented a multiyear R&D program to develop a better understanding of the physical and chemical behavior of CO_2 stored in deep saline formations. CO_2 from the Dakota Gasification facility in Beulah, North Dakota, has been used for enhanced oil recovery (EOR) operations at the Weyburn EOR project[40]. , The use of "natural" CO_2 for EOR has been commercially applied in the U.S. since 1972. However, CO_2 from a commercial scale coal-fueled electric generating facility has yet to be captured, compressed, transported and used for EOR or stored in deep geologic formations.

[39] Levelized cost of electricity (LCOE), based on 90% capture and storage in a saline formation, versus a supercritical pulverized coal power plant without CCS.
[40] Weyburn Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/weyburn.html .

In addition to ongoing R&D, several commercial scale CCS demonstration projects are underway in collaborative efforts by the public and private sectors (see Attachment 1). The first of these facilities (Southern Company's Kemper County IGCC) is scheduled to commence operation in 2014.

The challenge for CCS is four-fold:

- ***Continue to support the on-going First Generation CCS demonstration facilities now under construction or in planning.*** These projects will integrate many of the components needed to demonstrate CCS at commercial scale electric generation facilities so that we may start "learning by doing." These plants are not expected to be commercially competitive absent the substantial government subsidies that are being provided. It is expected that second and third generation CCS facilities may also be economically challenged but their construction and operation is essential if we are to maintain progress and mature the technology.
- ***Accelerate research and development*** on second generation advanced CCS systems, especially capture technology (which contributes most of the total cost of CCS), to dramatically reduce cost and improve performance.
- ***Fund Second Generation CCS demonstration facilities*** to verify that the products of R&D will operate as expected at commercial scale.
- ***Create a legal framework*** for permanent storage of CO_2 that addresses private property rights and questions about the long-term liabilities related to CO_2 storage.

Introduction

CCS technology has been cited by most authoritative sources on climate change mitigation, including the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA), as a critical, if not the most important, technology to enable society to meet stringent greenhouse gas (GHG) reduction goals.[41] U.S. emissions of CO_2 are dominated by the electric power industry and transportation which contributed 34% and 27% of total U.S. emissions in 2010, respectively.[42]

CO_2 emissions from electric power production can be reduced by generating less electricity, generating electricity more efficiently, relying on electricity sources which are less carbon intensive, or capturing CO_2 from power plants. In 2010, coal and natural gas generated 69% of total U.S. electricity. EIA projects that coal and natural gas will still generate 66% our electricity in 2035.[43] This continued reliance on fossil fuels for power generation suggests that systems to capture and store CO_2 from power

[41] See: Energy Technology Perspectives – 2008, International Energy Agency, June 2008; and Carbon Dioxide Capture and Storage, Intergovernmental Panel on Climate Change, 2005.
[42] U.S. GHG Inventory – 2012, Table ES-7, USEPA, April 2012.
[43] Annual Energy Outlook – 2012, USDOE/EIA, http://www.eia.gov/forecasts/aeo/er/ .

plants will be essential to reducing CO_2 emissions not only in the United States but globally where use of fossil fuels in developing countries is projected to increase dramatically.

The technologies needed to capture CO_2 and store CO_2 are separate, and each faces its own set of challenges. The three primary technologies for capturing CO_2 are in various phases of commercial development and include post combustion capture using amine based solvents, pre-combustion capture systems associated with integrated gasification combined cycle (IGCC) and oxycombustion-based capture systems.

These three CO_2 capture technologies as well as the processes used to clean, compress, transport, and store CO_2 are reviewed in this paper.

Carbon Capture

Three types of carbon capture systems are currently under development::

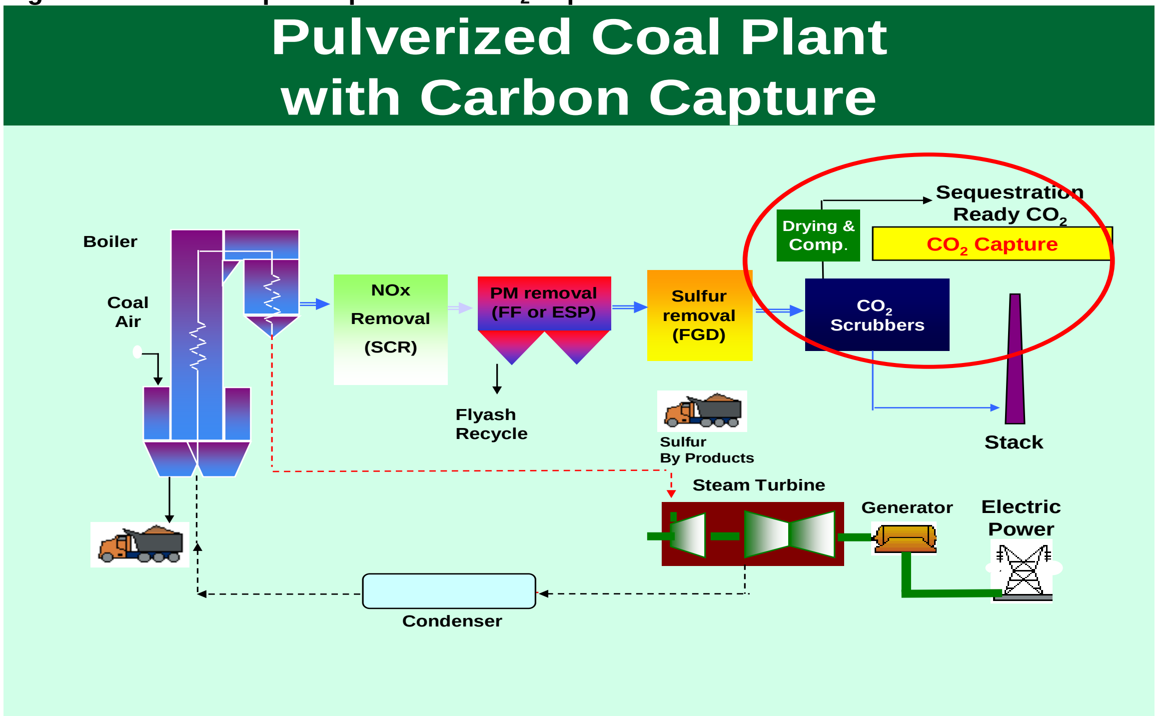
- Post-combustion capture (PCC) systems, which utilize chemical-based solvents, are used to separate and concentrate CO_2 from the flue gas stream of a coal fired boiler. Other non-solvent based PCC technologies are also under development.
- IGCC technology converts coal to a combustible gas (synthesis gas) and separates the CO_2 from the synthesis gas prior to combustion (rather than from the flue-gas after combustion).
- Oxy-combustion systems, that resemble traditional coal-fired power plants, use pure oxygen mixed with recycled flue gas rather than air for combustion. Oxycombustion produces a flue gas stream that is highly concentrated with CO_2. This concentrated stream of CO_2 can be more easily separated, cleaned and compressed than the CO_2 in the flue gas of a conventional air fired boiler. Once the CO_2 has been captured it must be compressed into a liquid form, transported by pipeline, injected into deep saline formations for permanent storage or used beneficially for other purposes, including enhanced oil recovery (EOR).

<u>Post-combustion Capture systems</u>

Post-combustion CO_2 capture systems add a CO_2 “scrubber” to remove the CO_2 from combustion gases. The CO_2 scrubber is located after the traditional Air Quality Control System. Figure 1 presents a simplified diagram of a pulverized coal power plant equipped with post-combustion CO_2 capture and compression.

ATTACHMENT A

Figure 1. Pulverized power plant with CO_2 capture.



Current PCC systems use amine based solvents for capture. The amine is sprayed into an absorber vessel where the CO_2 is stripped from the flue gas. In a separate desorber vessel the liquid solution is heated and the CO_2 is released. The concentrated CO_2 gas can then be compressed into a liquid for pipeline transport.

While CO_2 capture systems using amine solvents are commercially available today, these systems operate under very different conditions from an electric generating facility. For example, amines have been used to separate CO_2 from other gases in the oil/gas processing and petrochemical industry for over 60 years. However, these systems typically operate under high pressures (20 – 30 times atmospheric pressure) and a pressure swing process can be used to separate the CO_2 from the solvent. This is not the case in power plants where PCC systems will operate at roughly atmospheric pressure.

There are several impediments to deployment of PCC technology:

- Due to the low operating pressure, a power plant system will need to use heat to force the release of CO_2 from the solvent. This operating condition requires that a huge amount energy from the plant be used to heat the solvent in order to release the CO_2. The solvent must then be cooled before being returned and reused in the absorber tower. This requires additional energy, as well as additional cooling water for the facility.
- A large amount of electricity is needed for CO_2 compression. In total, the energy requirement for CO_2 capture and compression is about 30-35% of the total energy produced by the power plant.

- Contaminants in the flue gas can degrade the solvents and corrode process equipment. New designs and process adaptations must be developed to avoid these problems.
- No existing power plant has integrated commercial scale carbon capture and power production. System integration is critical to the successful application of PCC systems for CCS.
- The application of CCS to power generating facilities can double the cost of electricity from the plant compared to a conventional pulverized coal system without CCS.[44]

Progress on CCS technologies is expected to result from multiple cycles of research and development as well as complementary commercial scale demonstrations (learning by doing). Two power plants utilizing first generation CCS technology are under development and will demonstrate post combustion capture technology. The two projects are:

- The Tenaska Trailblazer plant, a 600 MW(net) supercritical pulverized coal power plant located near Sweetwater, TX. The unit will achieve 85-90% CO_2 capture using the Fluor Econamine FG Plus solvent technology. Captured CO_2 will be used for EOR in the nearby Permian Basin. The project, estimated to cost $3 billion, has obtained needed permits and completed its detailed Front End Engineering Design (FEED) study.[45] The project has not been awarded federal funding, but it may be eligible for state financial incentives.
- The W.A. Parish retrofit project, Houston, TX. The project will also apply Fluor Corporation's Econamine FG Plus post combustion capture technology. The system will be retrofit to a partial flue gas stream from the existing Parish power plant to remove 90% of that gas stream's CO_2. Captured CO_2 would be used for EOR in Texas Gulf Coast oil fields. The project was initially conceived at 60 MW with about 500K tons per year of CO_2 captured. However upon further evaluation it was determined that the volume of CO_2 supplied by the plant was insufficient to interest oil producers to use the CO_2 for EOR and the project size was increased to 240 MW. This increased the cost of the project by at least 3 times the original projection of $334 million. The project is presently looking into ways to fund this additional cost and DOE is evaluating the potential for added federal cost share.[46] Other CO_2 post combustion capture projects in the United States, Canada, Australia and Germany were announced and pursued but later abandoned due to costs, public opposition or other reasons.

Ongoing CCS R&D for conventional coal-fired power plants, conducted primarily via collaborative efforts by the public sector and the private sector, is described in DOE publications.[47] DOE-supported post-combustion capture projects currently include laboratory and bench scale research on 11 capture

[44] Based on calculations performed by CURC as part of the CURC-EPRI 2012 Fossil Energy Technology Roadmap assessment.
[45] Trailblazer Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/tenaska.html .
[46] W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/wa_parish.html ..
[47] The US DOE's CO_2 Capture RD&D Program, J. Ciferno, NETL, Presented at 2011 NETL CO_2 Capture Technology Meeting, August 2011, http://www.netl.doe.gov/publications/proceedings/11/co2capture/index.html#mon1. Other presentations available at this same website have additional detail on specific R&D projects.

solvents, 4 solid sorbents, and 4 membranes. Pilot-scale research is being performed on 4 solvents and 1 membrane technology. In addition to R&D in second generation capture systems, R&D is also underway to improve the efficiency of the basic power plant, which reduces the amount of CO_2 produced.

As first generation capture systems are demonstrated, R&D in second generation CSS technologies must proceed. If adequately funded, these R&D activities can result in development of second generation PCC demonstrations by 2025.[48] Given successful demonstration, these advanced PCC technologies could begin commercial operation by 2030.

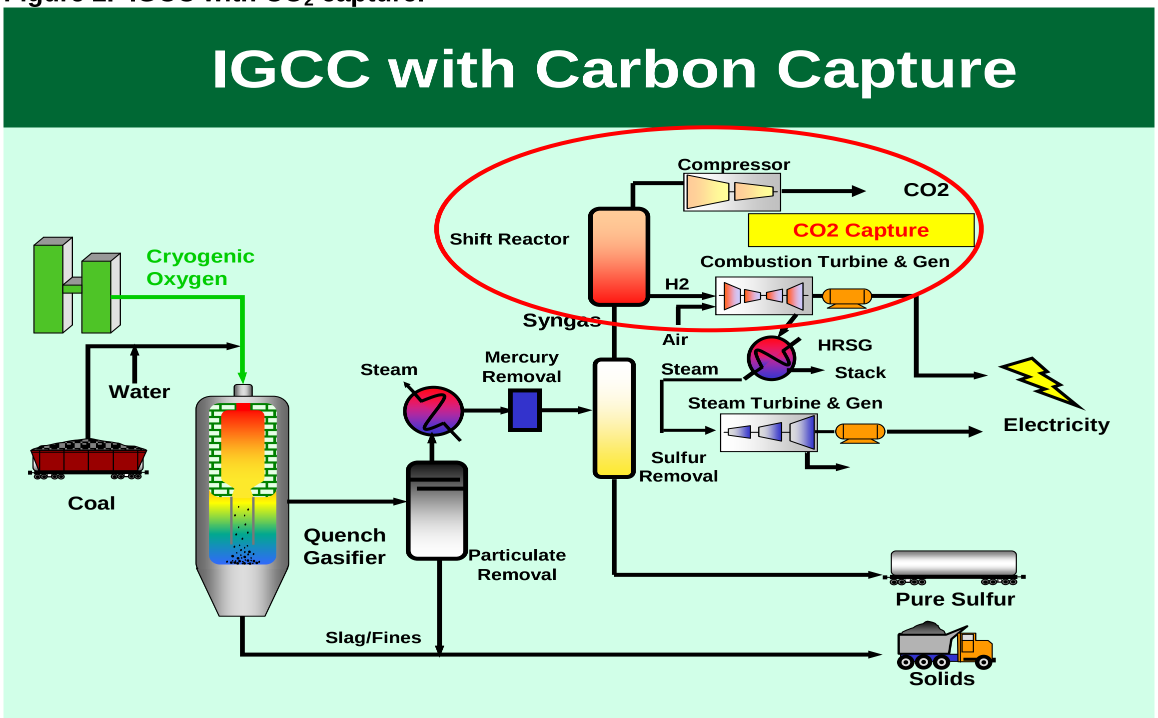
Gasification Based Systems

Gasification based CO_2 capture systems work in a different manner than post-combustion systems. These systems take advantage of the fact that coal gasification produces a pressurized fuel gas (referred to as "synthesis gas") from the gasifier. This synthesis gas is converted to mostly hydrogen and CO_2, stripped of CO_2, cleaned, and then used to generate electricity in a combined cycle power system known as Integrated Gasification Combined Cycle (IGCC).[49] Figure 2 presents a simplified diagram of an IGCC power plant with pre-combustion CO_2 capture and compression.

[48] Op. Cit., CURC, 2012.
[49] Gasification systems can also be configured to produce synthetic natural gas, or to be converted to liquid fuels or chemical feed stocks, which are not included here.

ATTACHMENT A

Figure 2. IGCC with CO_2 capture.



A substantial amount of CCS R&D has been completed on IGCC systems. As a result, three DOE sponsored commercial-scale first generation demonstration projects are under development.

- The Texas Clean Energy Project (TCEP), led by Summit Power, is a "polygeneration" facility, designed to produce 245 MW of electricity, urea fertilizer, and CO_2 for EOR The plant will employ Siemens gasifiers and gas turbine/generators, and will use the Rectisol technology to capture 90% of the CO_2 produced. Overall project cost is reported to be $2.3 billion. The facility was originally announced to start operations in 2014.[52] The company has signed engineering, procurement, and construction contracts.[53] The construction start has been delayed.
- The Kemper County IGCC Project, led by Mississippi Power, a subsidiary of Southern Company, is a lignite fired IGCC. The plant is a 524 MW unit designed for 65% carbon capture with captured CO_2 being used for EOR. The project employs the Transport Integrated Gasification (TRIG) system developed by Southern Company and KBR with the support of DOE. The project is estimated to cost $2.4 billion and is currently under construction. Start-up is scheduled for 2014.[54]
- The Hydrogen Energy California (HECA) Project is another polygeneration project designed to gasify coal and petcoke and will produce 250 MW of electricity, urea for fertilizer and CO_2 for EOR. The facility will use the Rectisol technology to capture 90% of the CO_2 produced by the plant. Construction was originally scheduled to begin in 2012, with plant operation scheduled for late 2016.[55] The construction start has been delayed.

More R&D is needed to reduce the cost and improve the performance of IGCC systems equipped with CO_2 capture systems. Current R&D addresses both fundamental design of the IGCC system,[56] and improvements specific to capture systems. As with post-combustion systems, DOE and industry are collaborating on a range of innovative CO_2 separation techniques at laboratory, bench and pilot-scale.[57]

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power output and better efficiency but these H class turbines are not ready for use in IGCC systems that capture most of the CO_2.

[51] Op. Cit., CURC, 2012.
[52] TCEP Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/tcep.html .
[53] Summit's TCEP reaches major milestone, Summit Power, February 14, 2012, http://www.summitpower.com/in-the-news/summits-texas-clean-energy-project-reaches-major-milestone/ .
[54] Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/kemper.html .
[55] HECA Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/heca.html .
[56] Gasification Systems, USDOE/NETL, http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/project-information.html .
[57] Op. Cit., NETL, August 2011.

With success of the First Generation demonstration facilities and the DOE's ongoing R&D program, Second Generation pre-combustion CCS systems with substantial improvements in cost and performance could be demonstrated at commercial scale by 2025.[58] Replications of these demonstration projects could lead to deployment of commercial systems by 2030.

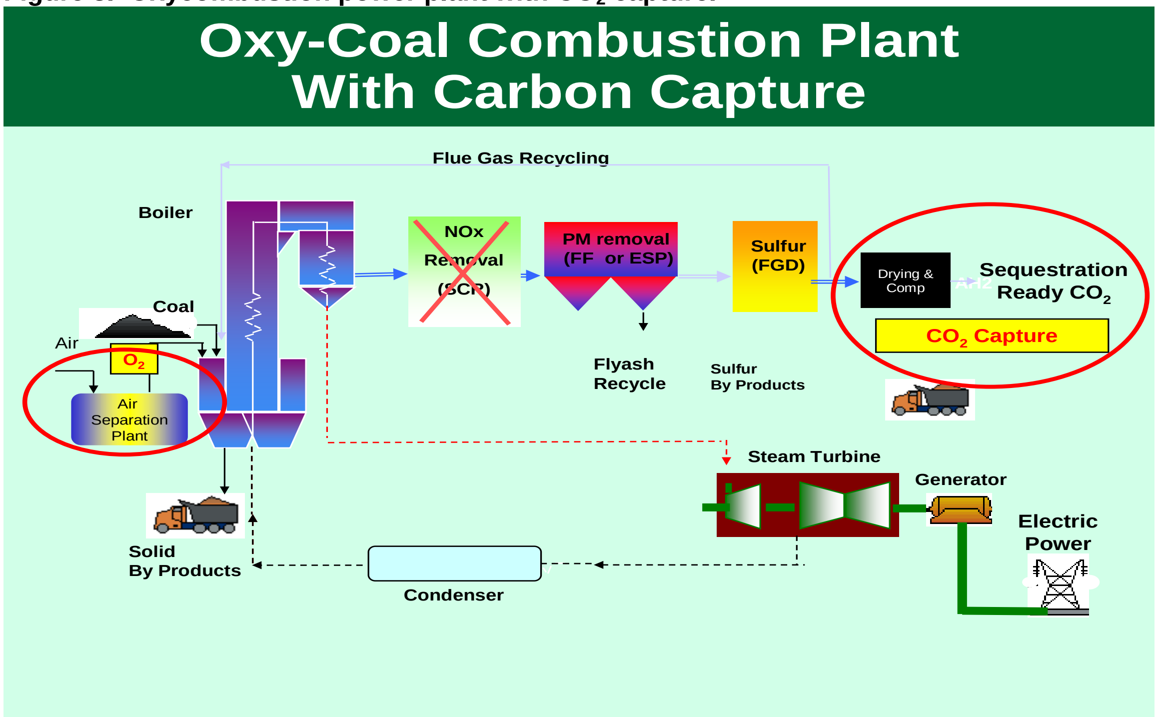
Oxy-combustion systems

Oxy-combustion systems generally resemble traditional pulverized coal or circulating fluidized bed power plants. However, there are some differences. First, high purity oxygen, instead of air, is used in the combustion process. At present Air Separation Units (ASU) are used to provide the large volume of oxygen needed for the oxycombustion process. Second, as the combustion of coal with high purity oxygen would produce flame temperatures that are too high to use in a conventional boiler design, a portion of the flue gas from the boiler is recycled and mixed with the oxygen to reduce the flame temperature and provide sufficient flue gas volume to support the proper heat transfer process in the boiler. Third, the CO_2 rich flue gas must be cleaned and processed to remove particulates, SOx, NOx, mercury, water vapor and other contaminants prior to compression, transport and storage.

The inherent advantage of oxycombustion systems is that the CO_2 in the flue gas is much more concentrated (and therefore less costly to capture) than CO_2 in the flue gas from a traditional power plant using air as an oxidant. However, this advantage is diminished somewhat by the capital and operating cost of the oxygen plant. Figure 3 shows a simplified diagram of an oxycombustion power plant with CO_2 capture and compression.

[58] Op. Cit., CURC, 2012.

Figure 3. Oxycombustion power plant with CO_2 capture.



There are several challenges that Oxy-combustion systems must overcome:

- Oxycombustion has yet to be demonstrated at large scale. The only experience to date comes from pilot scale facilities the largest of which is approximately 10 MW electric.
- An oxygen plant (ASU) is required to supply the oxygen for the oxycombustion process. It is an expensive and energy intensive process.
- A means of compression and purification (CPU) of the captured CO_2 is required. While compression is common to all CCS process it is still an expensive and energy intensive process to integrate into the plant operation.
- The integration of a large ASU and CPU into the operation of a power plant has never been demonstrated.
- The recirculation of large volumes of flue gas has never before been demonstrated.
- Similar to the cost of electricity from the other first generation CCS systems, the cost of electricity from oxycombustion power plants is expected to be very high.[59,60] Without a significant subsidy, the cost of electricity from any of the first generation CCS systems will not be competitive with conventional generating facilities.

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[59] The Cost of CO_2 Capture, Zero Emissions Platform, July 2011.
[60] Economic Assessment of Carbon Capture and Storage Technologies – 2011 Update, WorleyParsons and Schlumberger, for Global CCS Institute, 2011.

Oxycombustion technologies are considered to be less mature than pre-combustion and post-combustion CCS technologies. The FutureGen 2 project will repower an existing 200MW oil fired electric generating unit located in Meredosia, Illinois with a commercial-scale coal fired oxycombustion boiler design. This project is a collaborative effort between DOE and the FutureGen Industrial Alliance. The design calls for 90% capture of the CO_2 produced in the boiler with the CO_2 stored in a nearby geologic saline formation. Construction was scheduled to begin late in 2013, with start-up in 2015.[61] Due to a change of ownership in the project the construction start will be delayed by at least 1 year.

R&D on oxycombustion technology is on-going, including research on corrosion, CO_2 purification, chemical looping combustion, and lower cost methods of oxygen production.[62,63]

CO_2 Compression and Transport

Compression and pipeline transport of CO_2 are relatively mature technologies. Before the CO_2 can be transported by pipeline, it must be purified of any oxygen, sulfur compounds, water and other contaminants. It is then compressed into a liquid at about 2,200 psig for transport via pipeline. The petroleum industry has extracted "natural" CO_2 from underground reservoirs, cleaned, compressed and transported it by pipeline for various uses for over 30 years. As significant power is needed to compress CO_2 to liquid form, research is underway to develop less energy intensive methods of CO_2 compression.

CO_2 Storage

Two approaches are being pursued for CO_2 storage.[64] The first approach is injection into deep underground geologic saline formations. This resource has the potential to store over 450 years of U.S. CO_2 emissions at current emission rates.[65]

The second storage approach under consideration is use of captured CO_2 to enhance oil recovery (EOR) from mature oil fields. CO_2 injected into partially depleted oil reservoirs mixes with the remaining oil and lowers its viscosity allowing more oil to be extracted from the field. EOR has the potential to double the output from an existing oil field. Eventually the CO_2 displaces the oil in the underground reservoir and is left there to be permanently stored. EOR is a mature technology and has been in commercial use

[61] FutureGen Fact Sheet: Carbon Dioxide Capture and Storage Project, MIT CCS Project Database, http://sequestration.mit.edu/tools/projects/futuregen.html .
[62] Op. Cit., NETL, August 2011.
[63] Oxycombustion CO_2 Control, USDOE/NETL, http://www.netl.doe.gov/technologies/coalpower/ewr/co2/OxyCombustion.html .
[64] Carbon Storage, FAQ Information Portal, USDOE/NETL, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonstorage2.html .
[65] Carbon Storage, FAQ Information Portal, USDOE/NETL, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonstorage2.html .

since 1972. EOR projects are generally supplied CO_2 from low cost naturally occurring underground CO_2 reservoirs or the CO_2 is separated at relatively low cost from raw natural gas. Sale of CO_2 for EOR could partially offset the cost of capture for power generating facilities with CCS. However, with the relatively high cost of CO_2 capture from power plants using current technology, this revenue stream is still insufficient to make the cost of electricity from CO_2 capture plants competitive with conventional power generating facilities.

Research is ongoing to explore other opportunities for productive use of captured CO_2 such as converting the CO_2 into solid byproducts.[66]

Saline storage

It is believed that permanent CO_2 storage in deep underground geologic formations will be viable on a widespread basis. However, many financial, institutional, regulatory, and technical hurdles remain.[67] A variety of intermediate and large-scale CO_2 injection tests in diverse geologies are required to adequately characterize and validate this U.S. geologic storage resource. Much of this work is already underway through collaborative efforts by DOE and the private sector.[68]

The basic process for injecting CO_2 underground begins with identification of a suitable porous rock formation that is naturally "capped" by an impermeable rock strata. This cap permanently seals the injected CO_2 in the target formation so that it cannot escape back to the surface or into drinking water formations. Once the target formation is identified a well is drilled into the porous structure, and supercritical liquid CO_2 is injected with enough pressure to overcome the pressure within the porous formation.

Suitable storage formations are typically one-half mile to over one mile below the earth's surface. Depending on the size of the plant, the volume of CO_2 produced and the size and porosity of the saline formation it is anticipated that several injection wells could be needed over operating life of a power plant. Other test wells are needed to monitor the spread of CO_2 within the geologic formation to ensure that the CO_2 remains confined to the planned storage area.

[66] Carbon Storage, CO_2 Utilization Focus Area, USDOE/NETL, http://www.netl.doe.gov/technologies/carbon_seq/corerd/co2utilization.html .

[67] To address these challenges, multiple integrated, large scale (> 1 million tons / year) CO_2 capture and storage system projects are needed to prove out the technology.

[68] Carbon Storage: Program Overview, USDOE/NETL, http://www.netl.doe.gov/technologies/carbon_seq/overview.html .

When a formation has received its intended amount of CO_2, injection ceases, and the well is capped to ensure that it will not be a conduit for release of the permanently stored CO_2. Monitoring of the storage field will be required for some period of time to validate that the stored CO_2 does not migrate beyond the designated storage site and that it remains permanently stored in place.

The cost of transportation, injection and monitoring is projected to be relatively small compared to the costs of capturing CO_2. These costs will vary depending upon the local geology and the distance between the plant and the storage site.[69]

Injecting and storing gasses in deep geologic formations has been demonstrated to be technically viable. Natural gas has been successfully stored in geologic formations for many years. Injection of relatively low volumes of acid gasses into geologic formations has been in commercial use in Alberta, Canada since the 1980's. While large-scale injection experience has been promising, mainly in conjunction with EOR or enhanced gas recovery (EGR), there is limited CO_2 injection and storage experience from power plants.

A small number of industrial projects have demonstrated the feasibility of large scale (>1 million TPY) CO_2 storage in saline formations. The *Sleipner* project in Norway has been successfully storing about 1 million TPY of CO_2 co-produced with natural gas in deep saline formations since 1996, with no recorded leakage.[70] Two similar projects, the *In Salah* project in North Africa (1 million TPY) and the *Snohvit* project in the Barents Sea (0.7 million TPY), have been operational since 2004 and 2008, respectively, and are storing CO_2 produced from natural gas processing.[71]

The major barriers to deployment of saline CO_2 storage are:

- Geologic formations vary across the country. Some have features that make containment more certain than others. The best storage sites may not be located near existing power plants or where the power generation is needed.
- While the industry believes saline geologic storage of CO_2 can be as safe as natural gas storage and CO_2 use for EOR, the public's willingness to accept the geologic storage of large volumes of CO_2 remains uncertain. Education of all stakeholders is critical for successful implementation of large-scale storage facilities.

[69] Transportation cost of CO_2 varies almost proportionately with the length of pipeline required to transport the CO_2 from the power plant to the site of injection. If the captured CO_2 is transported over great distances then the cost of the pipeline could constitute a significant expenditure of the overall CCS system.
[70] The CO_2 sequestration project in Norway, the Sleipner project, uses an amine system to clean natural gas that is high in CO_2 content.
[71] Key Projects, Global CCS Institute, http://www.globalccsinstitute.com/ccs/key-projects .

- Monitoring, reporting, and verification (MRV) of CO_2 stored in saline reservoirs is required by regulation but remains an area of development.[72] Better tools must be developed to predict the capacity of storage reservoirs and monitor the lateral and vertical movement of injected CO_2 over time. Technology, know-how and experience from the oil and gas industries are expected to be useful in addressing this area of need.
- Regulations promulgated by EPA to protect underground sources of drinking water, pursuant to the Underground Injection Control (UIC) program include monitoring and financial assurances that last 50 years beyond the period in which CO_2 is injected into the formation.[73] This liability appears to be beyond the coverage available under existing insurance policies and could pose an unacceptable cost to power plant owners.
- Similarly a mechanism to address long-term storage integrity is also needed. A method to ensure perpetual monitoring and leak mitigation must be developed. The Interstate Oil & Gas Compact Commission (IOGCC) has published model rules[74] which offer one possible approach.

Basic research on storage is probably not as necessary to overcome these barriers as are experience and empirical data. To overcome these technical barriers some storage projects, preferably at well characterized sites that are inherently low risk, need to be built and tested to determine the true potential for safe and secure long term CO_2 storage.

EOR storage

Reports published by DOE/NETL conclude that 20 billion tonnes of CO_2 could be stored in the process of producing 67 billion barrels of oil via "next generation" CO_2-EOR.[75] For perspective, emissions of CO_2 from the U.S. electric power sector totaled 2.3 billion tonnes in 2010.[76] The concept of using CO_2 for productive purposes has generated the term: CCUS, or carbon capture, utilization, and storage.

From a power plant's perspective, the motivation for using CO_2 for EOR is twofold. First sale of CO_2 for EOR creates revenues that can partially offset the cost of capture and second, legal issues relating to property rights, monitoring, and long-term liability are more settled, and less stringent for EOR than for saline storage of CO_2.

[72] Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells, USEPA, 75FR77230, December 10, 2010.
[73] Ibid.
[74] CO_2 Storage: A Legal and Regulatory Guide for States, IOGCC, 2007, http://groundwork.iogcc.org/topics-index/carbon-sequestration/executive-white-papers/co2-storage-a-legal-and-regulatory-guide-fo .
[75] Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR), USDOE/NETL, June 20, 2011.
[76] Op. Cit., U.S. GHG Inventory.

In evaluating the economics of EOR projects, DOE has used a range of values for the price of CO_2 that are pegged to the global price of crude oil. For oil priced at $100 per barrel, the range equates to $38-58 per tonne of CO_2.[77] After subtracting transportation costs, (that could be significant depending on how far the EOR opportunity might be from the power plant) studies still suggest a significant offset to capture costs is possible.[78]

CO_2 storage in EOR fields also presents lower risk. With EOR storage, oil and water are withdrawn from the formation as CO_2 is injected, thereby limiting the increase in formation pressures. Lower pressure means diminished risk that the CO_2 will migrate from its intended storage area. Additionally, there is much more experience with EOR storage of CO_2 than with saline storage. This should mitigate some of the risks associated with storage liabilities.

Based on the DOE's analysis, EOR does not provide adequate capacity for storing CO_2 generated from all present and future fossil fuel power plants. Nevertheless, the fact that all but one of the current CCS demonstration projects are pursuing EOR storage suggests that EOR-based CO_2 storage (i.e., CCUS) may dominate CO_2 storage in the U.S. for decades.

DOE is working with industry to develop additional productive uses for CO_2 beyond EOR. Specific elements of the R&D can be found on the DOE's website for the CO_2 Utilization Focus Area.[79]

Legal ownership and Liability Issues Related to CO_2 Storage

Ownership issues associated with geological formations and the right to inject above, in or below minerals is an area of great uncertainty for CCS. Equally, the liability related to CO_2 injection operations and long-term maintenance remains uncertain and offers another potential barrier to large-scale storage projects.

Some states are advancing legislation to address the rights of land owners regarding mineral ownership and liabilities regarding CO_2 injection. The liabilities related to a CCS project include a local damage element during operations and post-closure phases, a global damage element for carbon reversal if there is leakage from the storage and personal injuries if there is personal or environmental damage that results from CO_2 leakage.

[77] Op. Cit., Improving Domestic Energy Security.
[78] It remains to be seen how much of this revenue will flow to the capture facility and how much will go to the owner of the connecting pipeline, or if the EOR developer will provide this much revenue. In some regions of the U.S., lower cost sources of CO_2 may be available.
[79] http://www.netl.doe.gov/technologies/carbon_seq/corerd/co2utilization.html .

Cost of CCS

Current technology

The addition of first generation CCS technology to a new coal fired power plant will approximately double the cost of electricity from that plant. A common cost metric used in the electric power industry is the "levelized" cost of electricity (LCOE). The LCOE represents the average cost over a defined period of operation, typically 30 years, and can be expressed in either nominal or constant (excluding the effects of inflation) dollars. LCOE includes annualized capital cost, fixed and variable operating and maintenance (O&M) costs, fuel costs, and in the case of CCS units, a cost for transportation and storage of captured CO_2. Table 1 and Figure 4 provide estimates of costs for 2010 vintage power plant technology, both with and without CCS, based on data from a 2011 analysis published by GCCSI.[80] As noted in Figure 4, the cost estimates in Table 1 and Figure 4 reflect an engineering assessment. No power plant equipped with commercial scale CCS has actually been built.

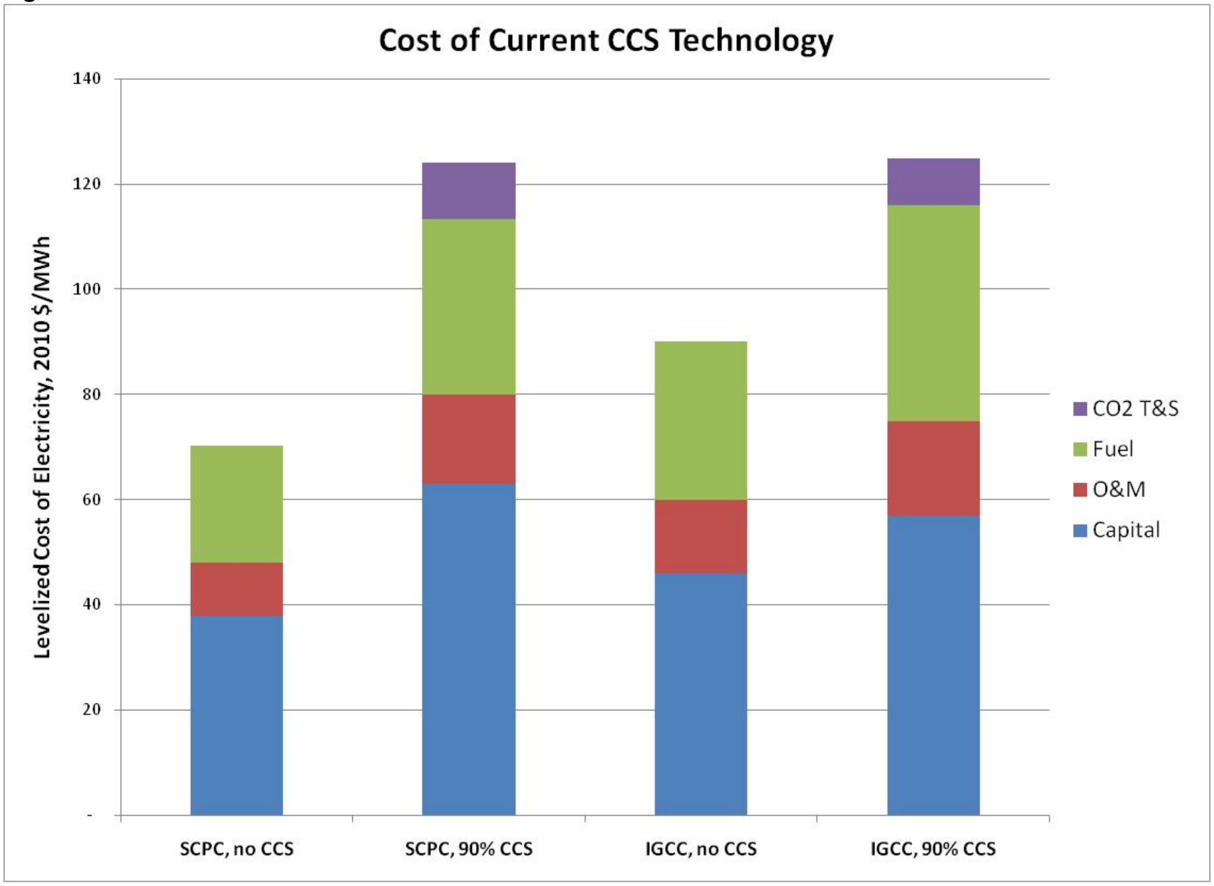
Table 4. Current CCS Technology Costs.

Cost in constant 2010 $/MWh	SCPC, no CCS	SCPC, 90% CCS	IGCC, no CCS	IGCC, 90% CCS
Capital	38	63	46	57
O&M	10	17	14	18
Fuel	22	33	30	41
CO2 T&S	-	11	-	9
Total	**70**	**124**	**90**	**125**

[80] Op. Cit., Economic Assessment of Carbon Capture and Storage Technologies. Published values were adjusted to reflect different assumptions regarding fuel costs and storage costs.

ATTACHMENT A

Figure 4. Current Power Plant CCS Costs.

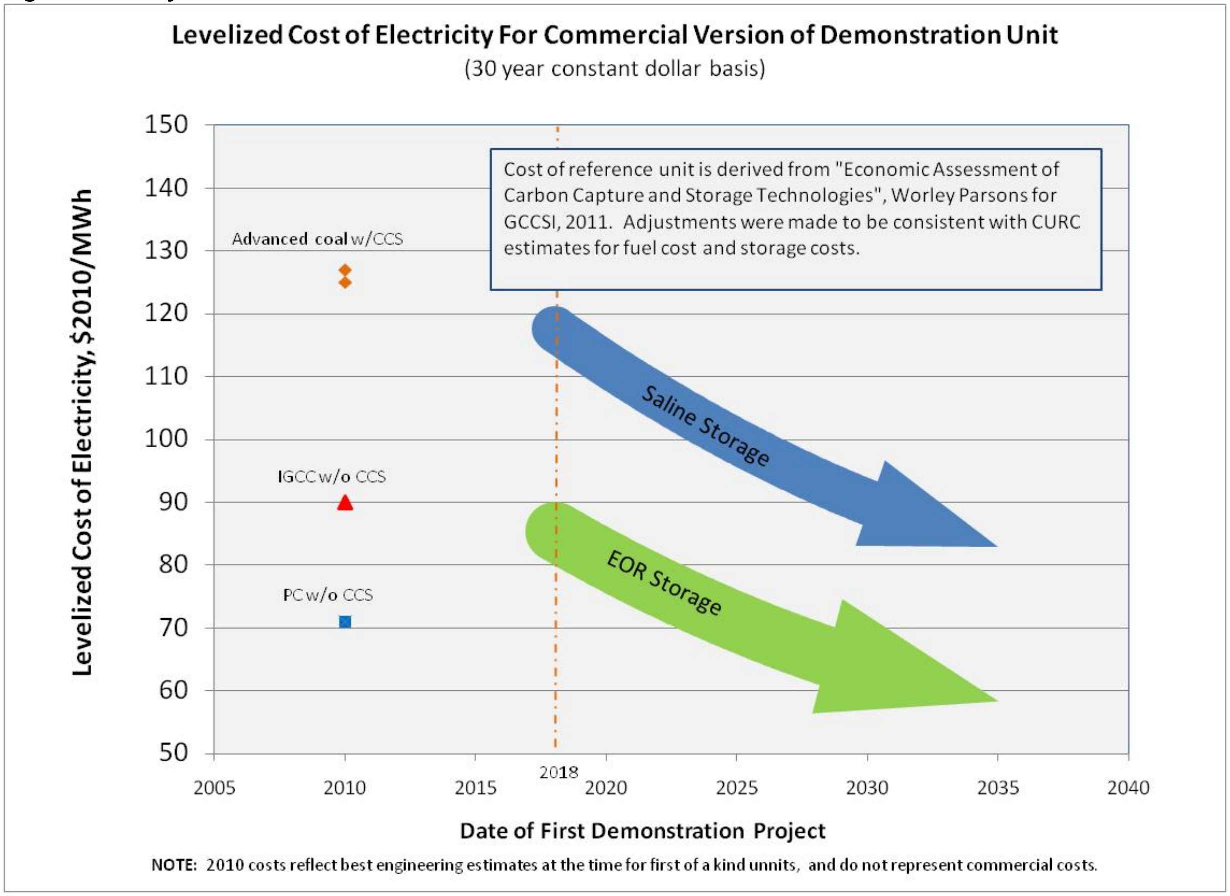


Future CCS Technologies

CURC projects that these costs could be dramatically reduced over the next 15 to 20 years through continued technology development via RD&D and the use of CO_2 from the capture plants for EOR. Revenue from CO_2 sales to EOR users would provide a revenue stream to offset a portion of the CO_2 capture cost. Figure 5 shows how these factors might combine for second and third generation power systems with CCS. Importantly, Figure 5 reflects the date at which a first of a kind demonstration of the technology is operational. A minimum of 4 to 7 years must be assumed before this initial demonstration project can be replicated and before a first commercial offering with guarantees of the replicated technology can be offered.

ATTACHMENT A

Figure 5. Projected costs of CCS.



Retrofit CCS Technology

The costs presented above reflect estimates for new coal-based power plants. Application of CCS to existing power plants will be more complicated and more costly. Much of the reduction in CCS system costs in the future is attributable to improvements in the basic power plant, such as higher operating efficiency. That type of fundamental redesign of the power plant is generally not practical for a retrofit CCS system.

Application of CCS to an existing power plant can double the facility's cooling water requirements, and requires large amounts of space – two factors that may prohibit the installation of CCS at many existing sites. An additional complication involves the large amount of energy that will be consumed by the CCS system. Lastly, some units are so small or so old that the large capital investment required by CCS would not be considered.

These factors make predictions regarding the current and future costs of retrofit CCS systems highly uncertain. The practice of applying a "retrofit factor", similar to what was done for less disruptive technologies like SO_2 scrubbers and NOx control systems may not be valid for a technology which poses the complex integration issues that come with CCS. That said, a rough estimate for current CCS technology cost at a plant meeting the general requirements of a good retrofit candidate would be 20-30% greater than the incremental cost of CCS on a new facility. In other words, if the incremental cost of CCS on a new pulverized coal system were $55/MWh, the cost of retrofitting that technology on an existing system might be $70/MWh.[81]

Three factors which could reduce the cost of CCS retrofit technologies are (1) capturing less than 90% of the CO_2, (2) selling the CO_2 for EOR; and (3) reduction in CO_2 capture costs through technology improvement

Conclusions:

CCS is an emerging technology which is likely to be demonstrated as technically feasible in first generation facilities over the next several years. However, these first generation CCS technologies are projected to double the cost of electricity and without significant subsidies these plants will not be competitive with alternative sources of electric power, such as coal or natural gas combined cycle systems that do not include CCS

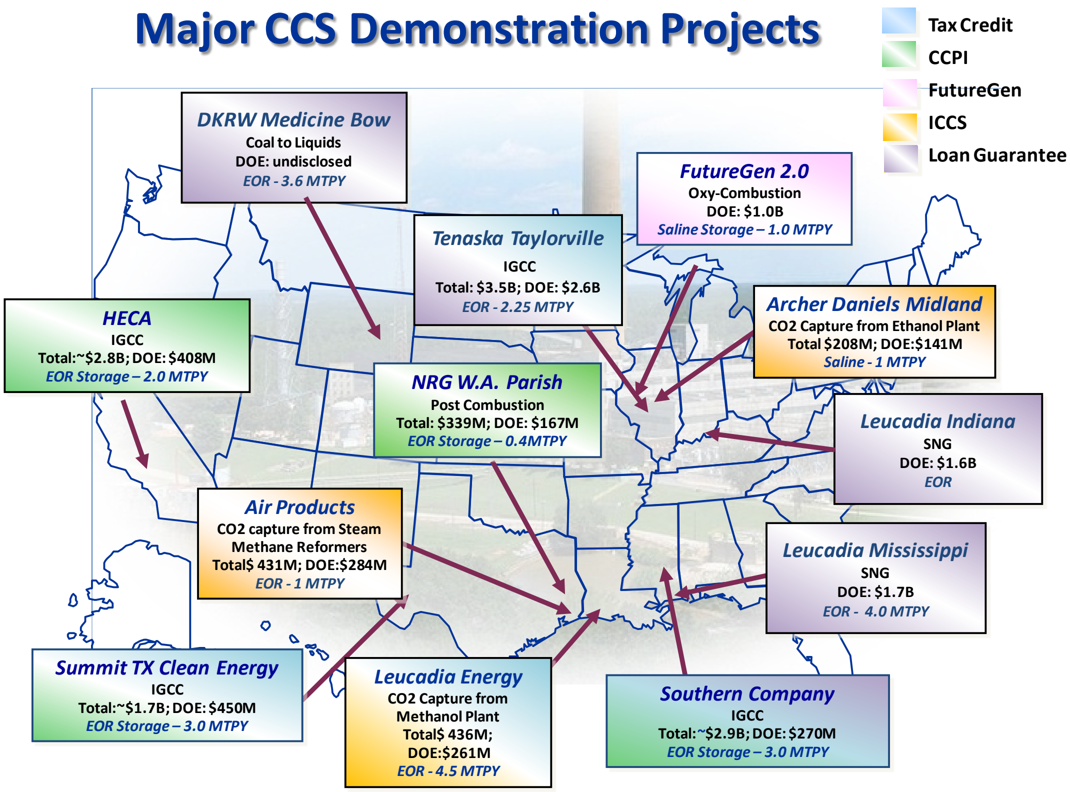
Continuing to pursue existing CCS RD&D programs, when combined with demonstration of second generation CCS technologies, could significantly improve the cost and performance of CCS systems by 2025. Deployment of these second generation systems could begin to occur as soon as 2030,

In addition to CCS technology development, we also need to overcome institutional barriers to CO_2 storage that include resolution of property rights, and creation of a system to address long-term monitoring and liabilities associated with CO_2 storage sites. The IOGCC has worked with a broad coalition of stakeholders to develop model legislation and regulations for states to consider in establishing these needed rules. Several states have already used the model rules to adopt such regulations and regulations are under development in other states.

[81] This cost would be additive to the current cost of electricity from the unit, typically about $30/MWh.

ATTACHMENT A

Attachment 1. Federally supported CCS demonstration projects.



*Additional Advances Coal Demonstration Projects include Duke Edwardsport IGCC (no C02 capture component) and Tenaska Trailblazer Energy Center (no public funds received)