BEFORE THE HOUSE SUBCOMMITTEE ON ENVIRONMENT AND THE SUBCOMMITTEE ON ENERGY OF THE COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

TECHNOLOGIES TO MEET EPA'S PROPOSED NEW SOURCE PERFORMANCE STANDARD FOR CARBON DIOXIDE EMISSIONS FROM ELECTRIC GENERATING UNITS

TESTIMONY OF KURT WALTZER
MANAGING DIRECTOR
ON BEHALF OF THE CLEAN AIR TASK FORCE
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Chairman Stewart, Chairman Lummis and Ranking Members Swalwell and Bonamici, thank you for the opportunity to testify today. My name is Kurt Waltzer and I am the Managing Director of the Clean Air Task Force. The Clean Air Task Force is an environmental non-profit dedicated to catalyzing the development and global deployment of low carbon energy technologies, and other climate protective technologies, through research, public advocacy leadership, and partnerships with the private sector.

The purpose of this hearing is to explore the technological requirements of EPA's proposed New Source Performance Standard. Before addressing this topic specifically, I'd like to make some general points.

First, wide-scale deployment of CCS technology is vital to averting the worst aspects of climate change. Almost two-thirds of the roughly 30 gigatons of CO_2 emissions released from human activity can be addressed through CCS technology. That's because CCS can be applied to two key emissions sectors—power plants and large-scale industrial plants. My remarks today will focus on the power sectors, where global emissions from fossil fuel power plants total about 11.9Gt per year. If no action is taken, annual power plant emissions will nearly double (24 Gt) by 2050. In developing countries, new coal plants are being built at an astounding rate. By 2015, 900 GW of coal power plants will be in operation in China—three times the size of US fleet. The vast majority of these plants are new. The vast majority of these plants are new. It is extremely important to drive controls on these plants, in the US and abroad, because plants such as these regularly last for fifty years or more, and if such development occurs without any control, we simply will not be able to achieve the deep reductions in CO2 emissions that are necessary to reduce the risk of catastrophic climate change.

Second, wide-use of CO_2 captured from power and industrial plants is vital to driving expanded use of enhanced oil recovery (EOR) in the US that will increase US oil production and decrease dependence of foreign oil. EOR recovers oil from aging oil field by injecting CO_2 deep into oil formations. The CO_2 mixes with the oil, freeing it from tight pores in the rock, and moving it to producing wells. EOR currently accounts for about 6% of US oil production. But new estimates from DOE suggest that there is enough capacity in US oil fields to store half the CO_2 emissions from the power sector over the next 30 years. That would produce almost 80 billion barrels of oil, or about 4 million barrels a day, which is over 50% of current US oil production.

Third, despite what some in industry have said, EPA's proposed CO_2 NSPS regulations are not the end of coal, but the beginning of CCS. In examining the proposed EPA's rules, the committee should consider the flexibility in the rule's structure and implementation, and how the rule helps drive CCS technology adoption. The flexibility of the proposed rules includes these features:

- An emission limit of 1100 lbs/MWh that can be met through partial, rather than full CO_2 capture. Partial capture is less expensive to implement than full capture (90% or more) on power plants.

- The proposed rules allow up to eight years to meet the rule's emission standard. This flexibility has a profound and positive impact on new coal plants. It means that a new plant can go into operation and if delays with establishing storage sites or pipelines are encountered, the plant can continue to run.

So as the subcommittees consider the status of CCS to meet the proposed EPA standards, it's key to focus the discussion within the context of the proposed rule. The rule is based upon partial, not full capture. The rule provides ample flexibility to meet this standard. And as I will describe later, at today's low natural gas prices, it is unlikely that any form of new coal plant will be built in the next decade whether or not it has CCS controls. Taken together, EPA's proposed rule is clearly a "Best System of Emission Reduction" for new coal plants[1].

I'd like to turn now to the status of CCS technology.

Status of CCS Technology

Large, integrated CCS projects began in the United States in the 1970 and 1980s at industrial facilities[2] where CO_2 was sold for enhanced oil recovery (EOR). Some of these projects capture and store 1 million tons CO_2 per year, 5 million tons CO_2 per year, and 7 million tons of CO_2per year. From its beginning in industrial facilities, CCS has migrated to power plants where it can reduce CO_2 emissions by greater than 90%. This combined industrial and power plant experience is significant. In the US we have over 4,000 miles of existing CO_2 pipelines and 40 years worth of experience with injecting managing and ultimately geologically trapping nearly a billion tons of CO_2 due to CO_2 enhanced oil recovery.

Because the component pieces of what we call CCS systems have been in widespread and safe use, separately, for 40 years or more, they are more than adequately

[1] section 111(a)(1) of the Clean Air Act (CAA) directs EPA to set standards of performance that: [R]eflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. 42 U.S.C. § 7411(a)(1).

[2] These include Val Verde natural gas processing plant, Enid Fertilizer project, Shute Creek natural gas processing plant, Great Plains Synfuels plant, Century natural gas processing plant

demonstrated to form the basis for an emissions standard for power plant combustion of fossil fuels. Indeed, the component parts of CCS systems are not only "adequately demonstrated" they are commercially available.

The absence of a U.S. regulatory driver has hampered the expansion of this technology. It is hard to convince an investor to put money into controls that are not required, or to convince a utility commission to grant rate recovery for investment in pollution controls that aren't required. That is true even though the enormous potential for future carbon emissions reductions associated with CCS systems makes investment in these systems very cost-effective. We need these systems to be the norm in the future, if our country is to continue to generate electricity using coal. We are not talking about an expensive technology with only marginal benefits. Instead, simply put, CCS systems are the only currently available technology that can permit the use of coal and gas for the production of electricity, at *near zero* carbon – and conventional air pollution -- emissions levels.

The migration of CCS technology to the power sector has started, and with stronger regulatory drivers, this migration will accelerate. Key projects for coal CCS include:

- The Dakota Gasification Plant (a lignite coal to Synthetic Natural Gas plant) located in North Dakota has been using pre-combustion capture technology since 2000, capturing 90% of its emissions and shipping it to permanent EOR sequestration in oil fields in Canada. The plant converts 18,000 tpd of lignite to SNG using gasification technology, capturing 1.8 MT CO_2/yr using Rectisol. The plant has been fully operational since 2000.

- In Kemper County Mississippi, Plant Radcliffe is a new 582 MW coal power plant currently under construction. When it opens in 2014, the plant will capture 65% of its CO_2 and sequester them deep underground through EOR activity. The emissions from this plant are estimated at 550 lb/MWWh (gross).

- In Odessa Texas, the Texas Clean Energy Project (TCEP) is expected to break ground later this year. The 400 MW project will turn coal into base load power, and fertilizer, and will produce CO_2 that will be sequestered deep underground through EOR activity. TCEP will capture over 90% of the CO_2 it would otherwise emit. The carbon dioxide emission rate for this plant when it goes into operation in 2015 will be 228 lb/MWWh (gross).

- FutureGen 2.0 is an oxy-combustion plant that will use Babcock & Wilcox (B&W) and Air Liquide technology. The 200MW plant will capture 90% of its carbon dioxide resulting in 1 MT/yr CO_2 captured, and will sequester all of that CO_2 in deep saline (non oil-producing/non-EOR) geologic layers in the Mt. Simon formation. The plant is expected to come online mid-2016.

- Plant Barry, Alabama- This post-combustion capture demonstration captures a slip stream of about 150,000 tons of carbon dioxide per year which is injected in a saline formation about 16 miles from the plant.

- Boundary Dam, Saskatchewan, Canada (Sask Power)- This retrofit of capture and sequestration technology onto an existing 110 MW pulverized coal unit will capture 90% of its CO_2 (1 million tons per year) for EOR and saline permanent sequestration. Start-up of the CCS controls will begin in late 2013 and go into full operation in spring of 2014.

Clean Air Act Frame and Costs

The Clean Air Act's framework recognizes that new sources of air pollution are generally in the best position to integrate pollution controls into project designs and to invest in new pollution controls. That is why the statute takes a forward looking and technology forcing perspective on performance standards, and requires every 8 year reviews to accommodate advances in technologies that have occurred in response to the standards. This approach has been an important contributor to the fact that U.S. air quality has gotten consistently better throughout the 40 years since the statute was passed in its current form. And it remains true, for CCS technology, although the Sask Power retrofit also shows that where an existing unit can accommodate it, CCS retrofits on older plants also are possible.

As noted above the Act directs EPA to set allowable pollutant emissions rates/standards of performance that take into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements.[3]

The courts also have articulated this inquiry as ensuring that the costs imposed by the standard are not "greater than the industry could bear and survive" but instead are costs to which the industry can "adjust" in a "healthy economic fashion to the

[3] The D.C. Circuit has fleshed out this mandate through a series of cases decided across several decades. *See*, *e.g.*, *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Lime Assoc. v. EPA*, 627 F.2d 416 (D.C. Cir. 1980); *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999). For instance, the court in *Essex* held that the standard must be based on a system of pollution control that: [H]as been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way*. 486 F.2d at 433 (emphasis added).

end sought by the Act as represented by the standards prescribed." *Portland Cement Assoc. v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

Thus, the statute requires EPA to balance the environmental and economic and energy related costs of requiring emissions rate-base performance standards. EPA is given a good deal of discretion to do this, although that discretion is not unbounded. The cost-effectiveness of any particular standard is particularly relevant to EPA's ultimate evaluation of whether the industry can bear the costs, as are questions about what the investment in new units in an industry looks like even before the standard has issued.

Here, the fact that CCS offers the opportunity for near zero emissions from coal generated electricity production, combined with the fact that the industry, as a matter of pure market economics, is now not investing in coal, are going to be significant factors. Courts have said that in situations like this, EPA's decision-making based on the future of the industry during the regulated period will be upheld. Additionally, EPA's past standards have required significant investments in controls representing, for example, 12 percent of the full investment in plant, and 5-7 percent annual operating cost increases, and in other instances 10s of billions ov dollars over a 20 year period, and have been upheld as reasonable given the pollution benefits to be achieved (and that we today benefit from). So, the relevant points in this inquiry are how much reduction in the pollution in question is available through application of the standard, and what the relevant price impacts of the standard will be where the industry is one that produces a commodity.

With this frame in mind, and to investigate the price impacts of partial CCS on a mid-western coal plant, CATF published a whitepaper in December, 2012 analyzing the potential cost of EPA's then-proposed 1000 pounds per megawatt hour standard for CO2, coupled with a longer time frame for compliance.[4] The analysis is based on cost estimates developed by NETL, but considers the flexibility mechanisms in terms of longer term compliance periods included in the initial proposed rule and as well as potential income from enhanced oil recovery. The current proposal also contains flexibilities, which are tied to the regulatory period of 8 years between review cycles for NSPS, whereas the original proposal included a 30 year averaging period for compliance, under which the CCS system needed to be operating in year 10. So, while our 2012 report is based on the 30 year

[4] "How Much Does CCS *Really* Cost? - An Analysis of Phased Investment in Partial CO_2 Capture and Storage for New Coal Power Plants in the United States", Clean Air Task Force, December 20, 2012. In its initial proposal, the Agency allowed for CCS phase in over a 30 year averaging period, wherein the partial capture and sequestration system did not need to be operational until year 10 of the plant's lifetime, and the emissions rate needed to be met over a 30 year annual averaging period. The current proposal also includes a longer time frame, which is tied directly to the "regulatory period" of 8 years between reviews.

averaging provision, it still requires immediate work on construction and near term operation of the CCS systems.

CATF's Modeled Cost Estimates Based on Performance Standard

CATF published a whitepaper in December, 2012 analyzing the potential cost of EPA's first proposed NSPS rule from April, 2012[5]. The analysis is based on cost estimates developed by NETL, but considers the flexibility mechanisms included in the proposed rule as well as potential income from enhanced oil recovery. It's important to note these cost estimates included scenarios where developers delayed the installation of CCS for up to a decade, based on the proposed rule flexibility. Under the current proposed rule, developers would likely delay installation seven or eight years at most. Thus while the cost numbers will directionally stay the same, they may be somewhat higher than is outlined below. CATF will update this analysis based on the most recent proposal in the future.

The results are summarized in Figure 1 below. We found that the 2017 COE for a new natural gas combined cycle plant would be $56/MWh (Case 4), while that for a new supercritical coal power plant without CCS would be $100 per MWh (Case 0), and that for a new supercritical coal power plant with enough CCS to meet EPA's Day 1 standard would be $124 per MWh (Case 1, including revenue from sales of CO_2 for EOR). $124 per MWh represents roughly a 24% premium on the price of power the facility owner must charge in order to comply with the proposed Day 1 standard by using CCS, if it is assumed to get full rate recovery in the investment in the technology. If, however, the investment in CCS is delayed by 10 years, and the appropriate anticipatory work is done, a new supercritical coal power plant with CCS might be constructed which meets EPA's Phased standard for only $113 per MWh, representing only a 13% power price premium over the uncontrolled coal case (again after accounting for revenue associated with selling the CO2 for EOR sequestration).

For Case 1 (50% CCS from Day 1), without EOR

For Case 1 (50% CCS from Day 1) without EOR revenue the COE premium is 36% (versus 24% with EOR revenue). For Case 3 (70% CCS, Phased approach) without EOR revenue the COE premium rises is 19% (versus 13% with EOR revenue). These cases are labeled Case 1b and Case 3b, respectively in Table 2. Relative power costs for our primary cases are indicated in Figure 1 below.

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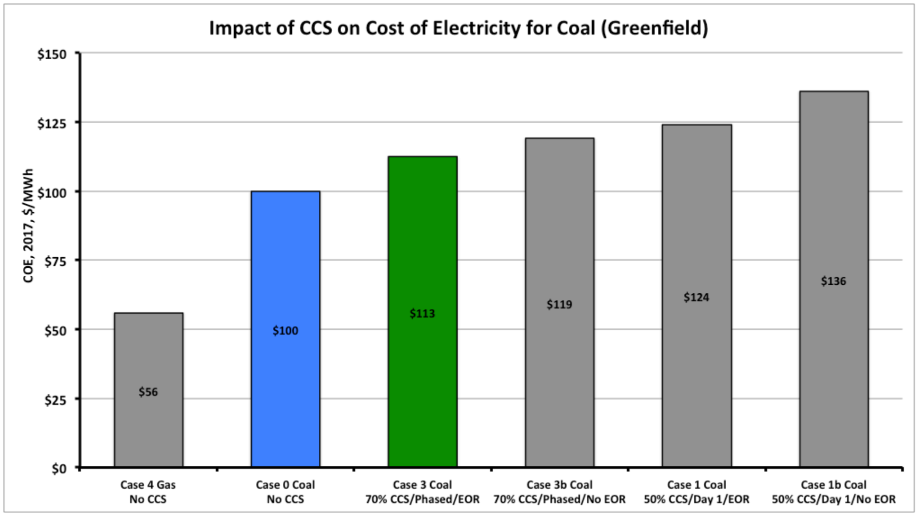
5 "How Much Does CCS *Really* Cost? - An Analysis of Phased Investment in Partial CO2 Capture and Storage for New Coal Power Plants in the United States", Clean Air Task Force, December 20, 2012

Figure 1



Cost Relationship to NSPS

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Carbon Capture

CCS is demonstrated and available for use at new coal- (and gas-) fired power plants and its core processes (CO_2 capture, transportation and sequestration) have already been utilized at large scale.

Pre-combustion capture of CO_2 is the process by which CO_2 is removed from the syngas of a gasification plant so that the remainder is mostly hydrogen. A 2010 U.S. DOE database of gasification projects lists 125 individual coal gasifiers (and 2 petcoke gasifiers) at 19 commercial projects which are used to produce either ammonia, substitute natural gas (SNG), or gaseous feedstock for liquid fuels production.[8] All three of those processes (ammonia production, SNG, and liquid fuels production) entail significant amounts CO_2 capture as a part of a purification process of the industrial gas products. *The total thermal capacity of these projects exceeds 20,000 MW, and some have been operating for decades.*

As noted above, CO_2 captured at the Dakota Gasification project is transported by pipeline to Canada, where it is used for enhanced oil recovery (EOR) and sequestered (see more below). CO_2 from the Coffeyville project is currently vented, but reportedly agreements have been signed to transport the CO_2 to Oklahoma for EOR and sequestration.

Summit's TCEP coal IGCC project in Texas will also use Rectisol®, and it was the basis for the CO_2 emission limits in a May 7, 2012 Indiana Department of Environmental Management (IDEM) air quality permit for a proposed gasification plant in Rockport, Indiana that would manufacture substitute natural gas from coal.[9]

In the coal gasification to power process, the CO2 must results in elevated-hydrogen syngas, which must be burned in a combined cycle combustion turbine to produce electricity for sale. This change presents no unreasonable technical challenges to the turbine, however. By 2006 Siemens had already accumulated more than 750,000 hours of operation with elevated- hydrogen fuels in

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[8] CATF analysis of DOE data. The DOE data is available at http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html,.

[9] *See* Permit IDEM No. T147-30464-00060, Condition D.4.9 (Available at http://permits.air.idem.in.gov/30464p.pdf).

combustion turbines,[10] and GE had accumulated over 900,000 hours.[11] Another turbine and gasification vendor, MHI, also offers an IGCC with Selexol™ to achieve 60-65 percent CCS.[12] As a result, in their evaluation of high-hydrogen combustion turbines for the HECA IGCC project with 90 percent CCS, HEI determined that "commercial guarantees for F class turbines operating on high-hydrogen fuels would be likely."[13]

Post-combustion capture is based on aqueous solutions of amines (a family of nitrogen compounds similar to ammonia) that are commonly employed in industrial processes outside the power generation industry. These systems have been applied successfully to exhaust from natural gas (including a combined cycle power plant) and coal plants.

Table 1

Vendor	**Location**	**Exhaust Stream**	CO_2 **Use**
ABB	Searles Valley,	Coal Boiler	Chemicals Industry
ABB	Warrior Run, MD	Coal Boiler	Food Industry
ABB	Shady Point, OK	Coal Boiler	Food Industry
TPRI	Shanghai, PRC	Coal Boiler	Food Industry
TPRI	Beijing, PRC	Coal Boiler	Demonstration, Food
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Aonla, India	NG fired SR flue gas*	Urea Production
MHI	Phulpur, India	NG fired SR flue gas*	Urea Production
MHI	Kakinada, India	NG fired SR flue gas*	Urea Production
MHI	Vijaipur, India	NG fired SR flue gas*	Urea Production
MHI	Bahrain	NG fired SR flue gas*	Urea Production
MHI	Phu My, Vietnam	NG fired SR flue gas*	Urea Production
MHI	Fukuoka, Japan	NG fired SR flue gas*	General use
MHI	Abu Dhabi , UAE	NG fired SR flue gas*	Urea Production
MHI	District Ghotoki,	NG fired SR flue gas*	Urea Production

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[10] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009) (citing Brown, P., *Siemens Gas Turbine H2 Combustion for Low Carbon IGCC*, (Oct. 2007)).
[11] Shilling, N., Testimony of Norman Shillingon Behalf of Joint Petitioners in Cause No. 43144 Before the Indiana Utility Regulatory Commission (Oct. 24, 2006).
[12] Sakamoto, K., "Commercialization of IGCC/Gasification Technology for US Market", Oct. 7, 2008.
[13] HEI, *HECA Feasibility Study Report #2 – Power Block Gas Turbine Selection* (May 29, 2009).

MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas*	Urea production
MHI	Plant Barry, AL	Coal Boiler	Demo (amine)
Fluor	Bellingham, MA, USA	Gas Turbine Exhaust	Food Industry
Fluor	Lubbock, TX, USA	Natural Gas	Enhanced Oil
Fluor	Carlsbad, NM	Natural Gas	Enhanced Oil
Fluor	Santa Domingo, DR	Light Fuel Oil	Enhanced Oil
Fluor	Barranquilla, Columbia	Natural Gas	Food Industry
Fluor	Quito, Ecuador	Light Fuel Oil	Food Industry
Fluor	Brazil	NG / Heavy Fuel Oil	Food Industry
Fluor	Rio DeJanero, Brazil	Steam Reformer	Methanol Productio
Fluor	Sao Paulo, Brazil	Gas Engine Exhaust	Food Productio
Fluor	Argentina	Steam Reformer	Urea Plant Feed
Fluor	Spain	Gas Engine Exhaust	Food Industry
Fluor	Barcelona, Spain	Gas Engine Exhaust	Food Industry
Fluor	Bithor County, Romania	Heavy Fuel Oil	Food Industry
Fluor	Cairo, Egypt	Light Fuel Oil	Food Industry
Fluor	Israel	Heavy Oil Boiler	Food Industry
Fluor	Uttar Pradesh, India	NG Reformer Furnace	Urea Plant Feed
Fluor	Sechuan Province, PRC	NG Reformer Furnace	Urea Plant Feed
Fluor	Singapore	Steam Reformer	Food Industry
Fluor	San Fernando, Philippines	Light Fuel Oil	Food Industry
Fluor	Manila, Philippines	Light Fuel Oil	Food Industry
Fluor	Osaka, Japan	LPG	Demo Plant
Fluor	Yokosuka, Japan	Coal/Heavy Fuel OIl	Demo Plant

Fluor	Botany Australia	Natural Gas	Food Industry
Fluor	Alton, Australia	Natural Gas	Food Industry
Alstom	Mountaineer, WV	Coal Boiler	Demo (ammonia
Alstom	Mongstad, Norway	NG turbine/refinery	Demo (ammonia
Aker	Mongstad, Norway	NG turbine/refinery	Demo (amine)

All of these vendors above, except perhaps for ABB, offer commercial PCC systems for coal power projects. In fact, Fluor has said "[t]he Econamine FG+ technology is ready for full scale deployment in: Gas- and Coal-fired Power plants,"[14] and recent commercial activity supports their assertion. A January 2012 front-end engineering and design (FEED) study for Tenaska Trailblazer Partners LLC for a 760 MW (gross) pulverized coal power plant with 85 to 90 percent carbon capture to be located in Texas concluded that "Tenaska and Fluor achieved the goals of the [carbon capture plant] FEED study, resulting in ... establishment of performance guarantees which, after the addition of an appropriate margin, were consistent with the expected performance in Fluor's indicative bid."[56] Regarding their post-combustion CO_2 capture, technology, MHI says "[i]t must also be reinforced that MHI is NOW ready to provide large scale, single train commercial PCC plants for natural gas fired installations (with completed basic design for a 3,000 [tons per day] plant train) and intends to leverage this experience for application to large scale CO_2 capture for coal fired flue gas streams."

<u>CO2 Pipelines</u>

There are presently approximately 4000 miles of CO_2 pipeline connecting naturally mined and anthropogenic sources of CO_2 with enhanced oil recovery projects.[15] In total, this system now carries approximately 50 million metric tons per year of CO_2 throughput. The Denbury "Green" pipeline, completed in 2009, extends from Jackson MS to Houston TX, collecting and delivering both naturally mined and anthropogenic CO_2.

Based on IGCC and industrial coal gasification projects that were planned in the Ohio River Valley, Denbury had proposed 320-mile long extension of the Denbury Green pipeline to southern Illinois. While the CO_2-source projects failed to

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[14] Reddy, S., *Econamine FG Plus Technology for CO2 Capture at Coal-fired Power Plants* (August 2008).

[15] Advanced Resources International, *U.S. Oil production potential from accelerated deployment of carbon capture and storage* (2010) (Available at http://www.adv-res.com/pdf/v4ARI%20CCS-CO2-EOR%20whitepaper%20FINAL%204-2-10.pdf).

materialize (due to several factors including low gas prices and withdrawal of state support) the extension would have connected these Midwest anthropogenic sources to fields in Mississippi, Louisiana, and Texas. Advanced Resources Inc. has estimated that three 800 mile-long pipelines could result in the storage of 30 years of Ohio River Valley EGU coal plant CO_2.[16]

There are half a million miles of natural gas and hazardous liquids pipelines rights-of-way, of which some routes might also provide rights-of-way for the build-out of CO_2 pipeline network. Elliott and Celia (2012)[17] have analyzed the storage resources in the proximity of the largest U.S. CO_2 sources in the U.S. – they report that large sources emitting 2.2 Gigatons of CO_2 are located within 20 miles of a saline reservoir.

Geologic Storage

Decades of experience in enhanced oil recovery (EOR), wastewater injection, and natural gas storage, combined with very large geologic CO_2 storage capacities in the U.S., provide confidence that long term CO_2 storage is both available and a best system of emissions reductions (BSER).[18] While commercial-scale deep saline CO_2 injection and storage experience is more limited, deep geologic injections and storage of wastewater, natural gas and for enhanced oil recovery (EOR) are commonplace in the U.S. CO_2 injection technology is grounded in a half- century of oil industry CO_2 management expertise. Moreover, natural gas companies routinely use deep geologic storage for natural gas reserves at over 400 sites in the U.S. injecting and storing natural gas in saline aquifers, depleted natural gas reservoirs and salt deposits. Including geologic wastewater injections, billions of tons of fluids are injected each year in the U.S.[19] Capacities for deep geological storage of CO_2 amount to hundreds, if not thousands of years, of present day CO_2 emissions rates. The U.S. Department of Energy's North American Carbon Storage Atlas (NACSA) released in 2012 estimates that there are approximately 500 years

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[16] Kuuskraa, V., Advanced Resources International, *Challenges of implementing large-scale CO_2 enhanced oil recovery with carbon capture and storage* (2010) (Available at http://web.mit.edu/mitei/docs/reports/eor-css/kuuskraa.pdf).

[17] Elliot T.R. and Celia M.A., *Potential restrictions for CO2 sequestration sites due to shale and tight gas productioni,* 46 Environmental Science and Technology, 4223-4227 (2012).

[18] Benson, S., *Monitoring carbon dioxide sequestration in deep geological formations for inventory verification and carbon credits*, Society of Petroleum Engineers SPE paper 102833 (2006) (Available at http://www.energy.utah.gov/government/docs/forum/dec2006/spe102833.pdf).

[19] Wilson, E. *et al*., *Regulating the ultimate sink: managing the risks of CO2 storage*, 37 Environmental Sci. & Tech 3476-3483 (2003).

of storage capacity for CO_2 emissions in North America.[20] Geologic formations that can accept CO_2 are widespread in the U.S., particularly in states that are rich in coal reserves. This means that where power plants are built close to coal resources, they will also be proximal to deep geologic storage resources. Furthermore, substantial capacity and transportation and injection infrastructure are currently available in EOR fields in the parts of the Rocky Mountains, Midwest, Southeast and parts of California. Cooperative research in the western U.S. is wisely evaluating development of storage resources near existing CO_2 pipelines.

Seismicity

An MIT report from April 2012 assessed the availability of geologic storage in the U.S., taking into account both geology and the fluid mechanics of injected CO_2, concluded that CCS is a geologically viable climate change mitigation option and that CCS can play a "major role" within the portfolio of climate change mitigation options even when taking into account pressure limitations[21]. MIT's model-based assessment of storage capacity for CO_2 captured from the power sector serves to counterbalance some of the broad, poorly supported assertions concerning pore pressure-based limitations and related seismic risk of large scale CCS made by Zobrak and Gorelick in their June 2012 piece. Such pressure limitations were also identified as a potential – but unknown – risk factor for induced seismicity in the National Academy of Science's June 2012 Report entitled "Induced Seismicity Potential in Energy Technologies". The MIT Report's analysis demonstrates that ample storage capacities are available for current and future power sector CO_2 emissions, even taking into account the purported pore pressure limitations.

Unlike Zobrak and Gorelick's commentary, which based its analysis solely on the Illinois basin, the MIT Report's analysis is based on storage supply curves for 11 sedimentary basins across the U.S., utilizing a model that accounts for CO_2 migration and trapping physics during the injection and storage process. Exh. Supp-2 at 5186. The MIT Report estimates that pressure-limited storage capacity for existing and future fossil fuel-fired power plants (including coal and natural gas) in the eleven identified basins would be adequate to stabilize CO_2 production from power generation for a century or more. This will continue to be true even if fossil fueled energy production continues to increase at current rates. Moreover, and

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[20] Press Release: "Energy Department Announced New Mapping Initiative to Advance North American Carbon Storage Efforts" (May 1 2012) (Available at http://energy.gov/articles/energy- department-announces-new-mapping-initiative-advance-north-american-carbon-storage. The 2012 North American Carbon Storage Atlas is available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf.

[21] Szulczewslki, M., et al., Lifetime of Carbon Capture and Storage as a Climate-Change Technology, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES Vol. 109, No. 14, at 5185-89 (April 3, 2012).

significantly, the eleven basins identified in the MIT report do not make up the entirety of potential saline storage basins in the U.S. Because the MIT Report describes only the sequestration potential capacity in those eleven U.S. basins, it underestimates U.S. CO_2 storage potential, as it does not take into account either the capacity available in offshore geologic formations or from next generation EOR projects.

Storage Regulations

A national regulatory framework now exists to support a determination that CCS is the best system of emissions reduction for any industry using that technology, and that CCS will be deployed in an environmentally protective manner. In 2010, EPA established a well class specifically designed for the geologic sequestration of CO_2 under the Federal Underground Injection Control program (UIC). *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells,* 75 Fed. Reg. 77,230 (December 10, 2010). These wells, deemed "Class VI" wells, are designed to ensure that injected CO_2 remains in a specified area and that CO_2 is properly monitored. EPA has also issued multiple guidance documents for Class VI wells that cover a variety of topics including, monitoring and testing, site characterization, area of review evaluation and corrective action, well construction, and financial responsibility.[22]

CO_2 sequestration may also concurrently occur in enhanced oil recovery (EOR) operations. UIC Class II injection permits are required for injections of CO_2 for EOR, and a process is available to obtain Class VI permit coverage for full-scale sequestration after oil production operations cease. *See* 40 C.F.R. §144.19 (2012).

Furthermore, under the U.S. Tax Code, 26 U.S.C. §45Q(d)(2), tax credits are available for those owners or operators who successfully sequester CO_2 from atmospheric release.

Therefore, facilities that utilize CCS must do so within a regulatory framework that ensures the CO_2 is properly accounted for, and has been isolated from atmospheric release, as well as that sequestration is occurring in a way protective of underground sources of drinking water. Where operators opt to conduct geologic sequestration of CO_2, as a part of or after conclusion of EOR operations, monitoring and reporting occurs pursuant to EPA's Greenhouse Gas Reporting rule under Subpart RR, 40 C.F.R. §98.440 *et seq.* (2012) (Geologic Sequestration of Carbon Dioxide).

The SDWA UIC Class VI and CAA Subpart RR rules, taken together, provide protection of underground sources of drinking water (USDW) and an accounting

[22] *See* EPA, Geologic Sequestration Guidance Documents (available at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm)

mechanism for measuring and crediting a source with the amount of CO_2 that is sequestered from atmospheric release.