SCIENCE OF CAPTURE AND STORAGE: UNDERSTANDING EPA'S CARBON RULES

JOINT HEARING

BEFORE THE

SUBCOMMITTEE ON ENVIRONMENT &
SUBCOMMITTEE ENERGY

COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

HOUSE OF REPRESENTATIVES

SECOND SESSION

MARCH 12, 2014

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CONTENTS

March 12, 2014

Appendix I: Answers to Post-Hearing Questions

Appendix II: Additional Material for the Record

SCIENCE OF CAPTURE AND STORAGE: UNDERSTANDING EPA'S CARBON RULES

WEDNESDAY, MARCH 12, 2014

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENVIRONMENT AND SUBCOMMITTEE ON ENERGY,
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY,
Washington, D.C.

The Subcommittees met, pursuant to call, at 10:07 a.m., in Room 2318 of the Rayburn House Office Building, Hon. David Schweikert [Chairman of the Subcommittee on Environment] presiding.

LAMAR S. SMITH, Texas
CHAIRMAN

EDDIE BERNICE JOHNSON, Texas
RANKING MEMBER

Congress of the United States
House of Representatives

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Subcommittee on Environment
and
Subcommittee on Energy

Science of Capture and Storage: Understanding EPA's Carbon Rules

Wednesday, March 12, 2014
10:00 a.m. – 12:00 p.m.
2318 Rayburn House Office Building

Witnesses

Panel 1

David Hawkins, Director of Climate Change Programs, Natural Resources Defense Council

Robert G. Hilton, Vice President, Power Technologies for Government Affairs, Alstom Power Inc.

Robert C. Trautz, Senior Technical Leader, Electric Power Research Institute

Scott Miller, General Manager and CEO, City Utilities of Springfield Missouri, American Public Power Association

Panel 2

Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
SUBCOMMITTEE ON ENVIRONMENT
SUBCOMMITTEE ON ENERGY

HEARING CHARTER

Science of Capture and Storage: Understanding EPA's Carbon Rules

Wednesday, March 12, 2014
10:00 a.m. – 12:30 p.m.
2318 Rayburn House Office Building

PURPOSE

The Subcommittees on Environment and Energy will hold a joint hearing entitled *"Science of Capture and Storage: Understanding EPA's Carbon Rules"* on Wednesday, March 12th, at 10:00 a.m. in Room 2318 of the Rayburn House Office Building. This hearing will explore the basis for the Environmental Protection Agency's (EPA) conclusion that carbon capture and storage systems (CCS) are adequately demonstrated as a technology for controlling carbon dioxide emissions in full-scale commercial power plants. Technical experts will focus on the potential use of CCS in both coal and natural gas fired power plants and the challenges associated with long-term geologic sequestration of carbon dioxide. The hearing will examine the EPA's rationale in proposing New Source Performance Standards (NSPS) for commercial power plants.

WITNESS LIST

Panel 1

- **David Hawkins,** Director of Climate Change Programs, Natural Resources Defense Council
- **Robert G. Hilton**, Vice President, Power Technologies for Government Affairs, Alstom Power Inc.
- **Robert C. Trautz**, Senior Technical Leader, Electric Power Research Institute
- **Scott Miller**, General Manager and CEO, City Utilities of Springfield Missouri, American Public Power Association

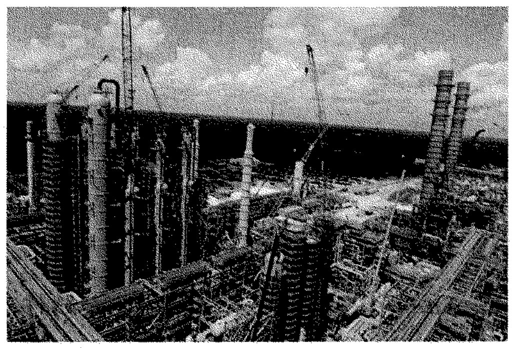
Panel 2

- **Janet McCabe,** Acting Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency

BACKGROUND

Regulatory Context:

Section 111 of the Clean Air Act (CAA) establishes a unique technology-based mechanism for controlling emissions from stationary sources. Section 111(b) provides EPA authority to promulgate performance standards which apply to new and modified sources. Specifically, EPA is directed to set standards based on "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."[1] In setting the standard EPA is given some flexibility in that "emission limits may be established either for equipment within a facility or for an entire facility."[2]



Southern's Kemper Project in Progress: "The Kemper plant will use two commercial-scale TRIG™ units to gasify lignite (low-rank coal that is mined next to the facility) to produce syngas. After the syngas leaves the gasifiers, it will be cleaned and used as fuel for two combined-cycle power generating units with a net output of 582-megawatts of electricity." *Global CCS Institute Status of CCS.*

EPA first proposed a New Source Performance Standards (NSPS) for emissions for carbon dioxide (CO2) from power plants in 2012. However, after more than 2.5 million comments on the original proposal, EPA decided that a new approach was warranted and rescinded the original proposal.[3]

Simultaneously, on September 20, 2013 Administrator Gina McCarthy announced EPA's re-proposed CO2 NSPS for new fossil fuel-based electric generating units (EGUs), explaining, "These proposed standards reflect separate determinations of the best system of emission reduction (BSER) adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines."[4]

Under the proposal, EPA concluded that CCS has been adequately demonstrated as a technology for controlling CO2 emissions in full-scale commercial applications at coal-fired EGUs, while reaching the opposite conclusion—that CCS is not adequately demonstrated—in the case of gas-fired EGUs. Based on this determination, EPA proposed an emissions limit for coal-fired sources of 1,100 lbs of CO2 per mega-Watt-Hour (MWH) and proposed standards for natural gas combined cycle sources

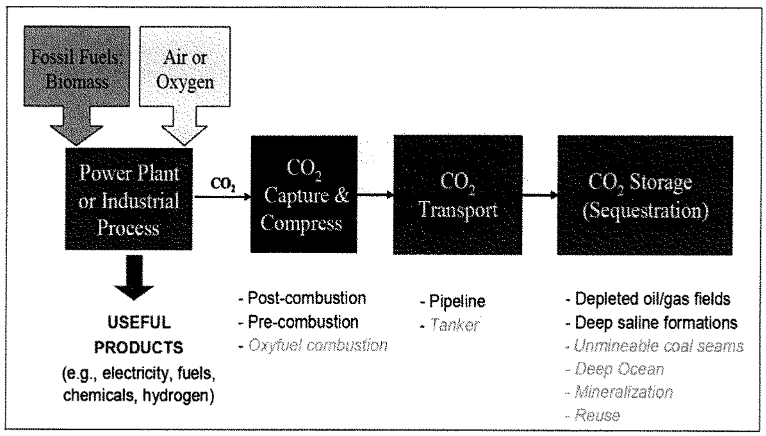
[1] Clean Air Act § 111(a)(1), 42 USCA § 7411(a)(1) (2006).
[2] http://www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf
[3] Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Proposed Rule, Preamble p. 14-5, Sep. 20, 2013.
[4] *Id.* at 15.

from 1,000 to 1,100 lbs CO2/MWH depending on the size and type of unit.[5] Electric Generating Units that primarily fire biomass are exempted from the proposed rule.[6]

In examining the regulatory impact, EPA asserted that "coal units built between now and 2020 would have CCS, even in the absence of this rule." In light of this modeling, "EPA projects that this proposed rule will result in negligible CO2 emissions changes, quantified benefits, and costs by 2022."[7] EPA sought comment for its proposal.

Technical Background:

Carbon capture and storage (CCS) methods capture CO2 from fossil fuel combustion before it is released into the atmosphere and store it underground in geological formations. Unlike some emission control devices, CCS is not simply one piece of technology; it requires a system of coordinating elements for successful implementation. Broadly speaking, there are four links in the CCS chain: capture, compression, transportation, and storage. Each link in the chain poses separate and distinct technology challenges. Among these components, capture is the most technology-intensive and costly. Storage, on the other hand, poses the greatest liability and regulatory obstacles.



Source: E. S. Rubin, "Will Carbon Capture and Storage be Available in Time?" Proc. *AAAS Annual Meeting, San Diego, CA, 18-22 February 2010*, American Academy for the Advancement of Science, Washington, DC.

In the NSPS proposal, EPA notes four projects that—with significant governmental financial assistance—are designed to use some type of capture technology. Although none of these projects have been completed, EPA anticipates at least one of these demonstration projects

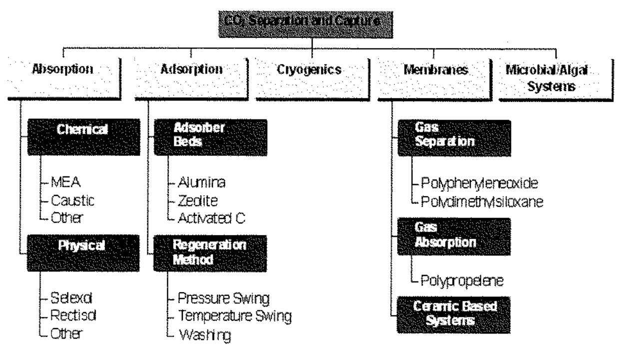
[5] *Id.* at 15-6.
[6] *Id.* at 30, fn. 8.
[7] *Id.* at 16-7.

will be operational in the near future. EPA cites Southern Company's Kemper County Energy Facility in Mississippi (pictured on p. 2), SaskPower's Boundry Dam CCS Project in Canada, The Texas Clean Energy Project in Odessa, and Hydrogen Energy California, LLC. Each of these projects, when completed, will utilize some elements of the CCS system EPA has selected in this proposal.

However, despite the promise of CCS technologies in power systems, currently there are no electric power plants operating with the CCS technology on a commercial scale.

Capture

CO2 capture may be achieved through pre-combustion, post-combustion, or oxy-combustion technologies. **Pre-combustion** removal methods typically require the high-concentration of CO2 associated with expensive gasification systems. **Post-combustion**, on the other hand, utilizes nitrogen-based solvents to scrub the CO2 from the flue gas. However, because post-combustion capture requires substantial heat input to release the CO2 and regenerate the solvent, it results in significant reductions in overall plant efficiency and a substantial increase in cost. A third process, **oxy combustion**, requires expensive and energy intensive air separation units. While oxy systems hold promise, they are more experimental. Overall, while capture technologies exist, the new challenges associated with operating at a larger scale will not become clear until after full-scale deployment.



Source: A.B. Rao and E.S. Rubin, "A Technical, Economic and Environmental Assessment of Amine-Based CO2 Capture Technology for Power Plant Greenhouse Gas Control," *Environmental Science & Technology. (See CRS Report 41325, p. 10.)*

Compression & Transport

Once the CO2 is captured, it must be compressed. As with capture, compression is an energy-intensive process. After compression, transportation to a storage site is required. Although dedicated CO2 pipelines have potential, technical challenges remain to ensure safe and reliable transport. Given the numerous policy and legal issues related to siting, permitting, and environmental requirements, creation of a full-scale CO2 pipeline infrastructure requires substantial capital investment and further regulatory development.[8]

[8] CONGRESSIONAL RESEARCH SERVICE, *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology.* Feb. 8, 2011. Available at: http://www.crs.gov/pdfloader/RL34307.

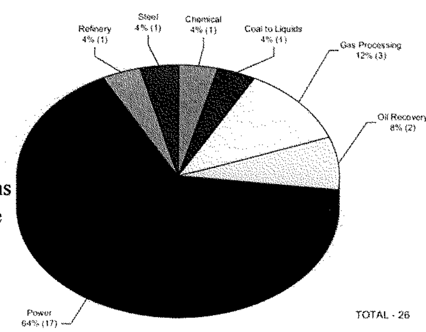
> **"To date, there are no commercial ventures in the United States that capture, transport, and inject large quantities of CO2 (e.g., 1 million tons per year or more) solely for the purposes of carbon sequestration."** *CRS Report 42496, p. 24, Feb 10, 2014.*

Storage

The final step in a CCS system is storage. However, permanently storing emissions is highly dependent on neighboring geology to the power plant. Geological storage is potentially available in deep saline formations, depleted oil fields, un-mineable coal seams, or for enhanced oil or gas recovery (EOR). However, lessons learned from failed storage sites in Africa demonstrate that maps of promising geologic formations do not always equate to locations where carbon storage should occur. Consequently, unresolved issues related to property rights acquisition, pore space management, regulatory structure, environmental protection issues, and liability remain a challenge. Significantly, EPA is unable to release operators from liability and litigation risk if a problem occurs in storing the CO2.[9]

Because of these challenges and the potential to offset the significant cost of CCS, the proposed rule focuses on the use of the captured CO2 for enhanced oil recovery (EOR). EOR has been used as a way to increase production in depleted oil fields by injecting CO2 and pumping previously unrecoverable oil to surface. While EOR provides outstanding opportunities to increase oil production in some regions, many locations do not have access to an EOR market. Absent a robust EOR market, CO2 would simply be stored geologically. Some have questioned whether EOR operators would be able to meet new reporting requirements contained in the NSPS proposal.[10]

> **According to the Global CCS Institute's 2013 report, 64% of the 26 <u>cancelled or delayed</u> projects are in power generation.**



Future of CCS Demand:

As discussions of new climate strategies continue, pressure for additional CO2 restrictions will likely increase. Simultaneously, worldwide energy demand, particularly in emerging economies, is growing rapidly. Much of the current and future demand for energy will

[9] CONGRESSIONAL RESEARCH SERVICE, *Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy.* Feb. 10, 2014. Available at: http://www.crs.gov/pdfloader/R42496.

[10] Philip M. Marston. GLOBAL CCS INSTITUTE. *A CO_2-EOR regulatory update from the US.* Feb. 17, 2014. Available at: http://www.globalccsinstitute.com/insights/authors/philipmarston/ 2014/02/17/co2-eor-regulatory-update-us.

continue to be supplied by fossil fuels. Consequently, projections suggest a strong long-term need for affordable technologies that can supply low-carbon energy from fossil fuels.[11]

Additional Reading:

CONGRESSIONAL RESEARCH SERVICE, *Carbon Capture: A Technology Assessment*. Nov. 5, 2013. Available at: http://www.crs.gov/pdfloader/R41325.

CONGRESSIONAL RESEARCH SERVICE, *Carbon Capture and Sequestration (CCS): A Primer*. July 16, 2013. Available at: http://www.crs.gov/pdfloader/R42532.

CONGRESSIONAL RESEARCH SERVICE, *Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy*. Feb. 10, 2014. Available at: http://www.crs.gov/pdfloader/R42496.

CONGRESSIONAL RESEARCH SERVICE, *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology*. Feb. 8, 2011. Available at: http://www.crs.gov/pdfloader/RL34307.

GLOBAL CCS INSTITUTE, *Global Status of CCS: 2013*. Oct. 10, 2013. Available at: http://www.globalccsinstitute.com/publications/global-status-ccs-2013/online/117741.

Hearing Charter. HOUSE SCIENCE, SPACE, AND TECHNOLOGY, SUBCOMMITTEE ON ENERGY AND ENVIRONMENT HEARING. *The Future of Coal: Utilizing America's Abundant Energy Resources*, July 25, 2013. Available at: http://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-20130725-SD001%20.pdf.

Philip M. Marston. GLOBAL CCS INSTITUTE. *A CO_2-EOR regulatory update from the US*. Feb. 17, 2014. Available at: http://www.globalccsinstitute.com/insights/authors/philipmarston/2014/02/17/co2-eor-regulatory-update-us.

Robert Meltz. CRS Legal Sidebar: EPA's Proposed CO2 Standards for New Fossil-Fuel-Fired Power Plants: Likely Legal Challenges. Sep. 26, 2013. Available at: http://www.crs.gov/LegalSidebar/details.aspx?ID=686&Source=search.

U.S. ENERGY INFORMATION ADMINISTRATION, *International Energy Outlook 2013: With Projections to 2040*. Available at: http://www.eia.gov/forecasts/ieo/pdf/0484(2013).pdf.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *Draft UIC Program Guidance on Transitioning Class II Wells to Class VI Wells*. Dec. 2013. Available at: http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13004.pdf.

[11] *See e.g.*, U.S. ENERGY INFORMATION ADMINISTRATION, *International Energy Outlook 2013: With Projections to 2040*. Available at: http://www.eia.gov/forecasts/ieo/pdf/0484(2013).pdf.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO2) Streams in Geologic Sequestration Activities*. Dec. 17, 2013. Available at: http://www.epa.gov/wastes/nonhaz/industrial/geo-sequester/prepub-co2-sequestration.pdf.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Final Rule*. 40 CFR Parts 72, 78, and 98. Dec. 1, 2010. Available at: http://www.gpo.gov/fdsys/pkg/FR-2010-12-01/pdf/2010-29934.pdf.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*. 40 CFR Part 60. Sep. 20, 2013. Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

Chairman SCHWEIKERT. The joint hearing of the Subcommittee on Environment and the Subcommittee on Energy will come to order, and there is the gavel.

I want to thank everyone for joining us today. Welcome to today's joint hearing titled "Science of Capture and Storage: Understanding EPA's Carbon Rules."

In front of each Member are packets containing the written testimony, biographies and Truth in Testimony disclosures for today's witnesses.

Before we get started, since this is a joint hearing involving two subcommittees, I want to explain how we will operate procedurally to all the Members and understand how the question-and-answer periods are going to work. After recognition of the Chair, and Ranking Members of the Environment and Energy Committee, we will recognize those Members present at the gavel in order of seniority on the Full Committee? Okay. It probably should be—well, we will go with the full Committee because that is how we wrote it before. And those coming in after the gavel will be recognized in order of arrival.

Let me recognize myself for just a couple minutes as sort of an opening statement. And I always drive staff a little nuts when I do this. I am going to go somewhat off script. I spent the last two days trying to read everything I get my hands on, the individual testimonies, data and information provided from the EPA and other just random articles. Fascinating subject area.

But my fear is, let us see if I can find an elegant way to express this, is sort of the law of unintended consequences. So as we are having the weaving of the discussion, what I would love woven into that discussion is the underlying technology, the underlying science. And symbolically, let us see if I can make this make sense. At home in my desk, I have the first-generation iridium phone—many of you remember that—will a little plaque on it saying just because you can engineer it, doesn't mean you should do it. That actually sort of weaves through this. We have much of the scientific capability, at least theoretically, but have we stressed it? Do we truly understand the unintended consequences? Do we also understand what carbon sequestration, or ACO_2, as it is often referred to in the literature, where we would be 50 years from now, 100 years from now, even after some of those capturing facilities have been shuttered? Where are we truly technology-wise? And then also then the weaving of the discussion of the proposed rule sets and are those rule sets appropriate, robust, and what is the cost curve on those for adoption, you know, have we made the cost curve something where now it is a theoretical discussion that we have now actually priced out of practice.

[The prepared statement of Mr. Schweikert follows:]

PREPARED STATEMENT OF ENVIRONMENT SUBCOMMITTEE CHAIRMAN DAVID SCHWEIKERT

I want to thank the witnesses for being here today. Your expertise is invaluable in helping this committee understand the practical and sometimes negative and damaging effects of EPA rulemaking. We are here to learn the facts about carbon capture and storage. And more specifically, we are here to see whether those facts support what EPA has proposed.

When I look at the EPA's new source performance standards proposal, I'm reminded of the Air Force's plans to develop a nuclear powered plane. That's right—a nuclear powered plane! They called it Project Pluto or "The Flying Crowbar."

Americans knew the power of atomic weaponry and military tools. The components had been tested. We had jet planes and nuclear reactors.

But something happened in moving from a dream to reality. The reality was that nuclear power worked, but only under specific controlled conditions, and in limited applications. And with a lot of supervision, testing and well trained staff.

Of course in hind sight, we understand that "Project Pluto's" nuclear powered aircraft would have been a disaster—and we luckily avoided that. We never built a fleet of "Flying Crowbars." In this way, Carbon Capture Storage is similar. It might work under specific conditions, but not everywhere. And we have no reason to believe it will work at the scale EPA is expecting us to believe.

This Administration has made no secret that it is an enemy to affordable fossil fuels, including coal. From what I have witnessed it appears the Administration would rather see carbon capture and storage fail altogether.

It was candidate Obama who famously said that if you want to build a coal plant you can—it's just that it will bankrupt you. With this rule it looks like the President is keeping that old campaign promise—to bankrupt coal. But at least they are being upfront about CCS for coal power. What's more troubling is what's hinted at but left unsaid. I want to know what this rule will really do, not just today but five, ten, twenty years down the road.

While the Administration likes to tout the economic benefits the natural gas revolution is bringing us, they are simultaneously attacking this affordable and renewable energy source. Likewise, this rule is at odds with the Administration's claimed goal: addressing global CO2 concentrations. The EPA's rule on carbon capture and storage would actually halt CCS research and development.

These rules are simply a thinly veiled attempt to prevent new coal power and eventually take down natural gas.

Does the EPA think Americans cannot see past their empty rhetoric? There are towns and communities all across this nation that want this administration to uphold their all of the above energy strategy.

But even if environmental extremists could prevent American's from enjoying reliable and affordable fossil fuels, developing countries have no intention of giving up fossil fuels. So an EPA rule that derails carbon capture and storage development will be disastrous.

Here's the bottom line: The Administration's rhetoric is disingenuous at best.

America is long overdue for a frank conversation about the future of our domestic energy solutions. No more hiding-the-ball. Let's take a step back from the end-of-the-world-scenarios-on both sides. Gather the facts. And have an honest discussion about the consequences of our policy choices. EPA's new source performance standards rule requires something that doesn't exist yet-full-scale power with at least 40% carbon capture and storage.

The Agency largely justifies the proposal on an assumption that captured CO2 will be used in enhanced oil recovery (EOR) operations.

The EPA has touted that the sale of CO2 would help offset the incredible costs of the capture side of CCS systems. But EPA's new source performance standards for power plants require full scale power with at least forty perfect carbon capture systems. In addition, the standards add new requirements to enhanced oil recovery options that effectively remove it as a compliance option.

These Oil Recovery operators can't comply, leaving power plants with no option but geologic sequestration. But permanent geologic sequestration has serious, unresolved scientific, legal, and regulatory problems.

This rule twists the clear language of the Clean Air Act and allows the EPA to require energy producers to use unproven technology. It sets up obstacles to compliance that undercut the very technology it claims to promote. This isn't about climate change. It's about expanding federal power and it sets a dangerous precedent.

Let's have a discussion that plays this rule out to its logical conclusion. Then we can consider if that's a place we want to go as a nation.

Chairman SCHWEIKERT. So with that as an opening statement, I will turn to my Ranking Member, Ms. Bonamici, for her opening statement.

Ms. BONAMICI. Thank you very much, Mr. Chairman, and thanks to the Chair of the Energy Subcommittee—I know Ms. Lummis is on her way—for holding this morning's hearing.

Today we are going to be discussing the performance standards proposed by the Environmental Protection Agency —EPA—for carbon dioxide emitted from new power plants. This is a hearing that is similar to one we held last fall, but this time we have the opportunity to hear directly from the EPA about this important issue, and I would like to thank Acting Administrator Janet McCabe for being here today and I would also like to thank the witnesses on our first panel for their thoughtful testimony, which I have reviewed.

Last year, President Obama laid out an agenda to address one of the biggest environmental challenges of our time: climate change. A key component of that plan, and any effort to reduce the amount of carbon emitted by the United States, is the need to significantly lower the amount of carbon produced during electricity generation. Emissions from power plants represent about a third of the greenhouse gases produced by the United States, and EPA's proposed rule takes an important first step in tackling this major source of carbon pollution.

To emphasize: the proposed rule sets carbon limits on new power plants, not existing plants or those under construction. Looking at current and future market conditions, especially competitive natural gas prices, it is likely that many if not most new power plants will be able to meet the proposed carbon limits. It is the market, not the proposed rule, that is contributing to the proliferation of natural gas power plants over coal. In my home State of Oregon for example, our last coal plant is scheduled to be closed by 2020, and some of that generation capacity will be replaced with a natural gas plant.

The proposed EPA rule will create a market incentive for the continued development and promotion of carbon capture and storage, or CCS, technologies. The advancement of CCS technologies is essential if new coal power plants are to operate in the low-carbon future we must achieve.

I also want to point out that when EPA determines the best system of emission reduction, it is actually required to promote the development of technology. I am sure we will hear much more on the state of CCS technologies from today's witnesses. That technology development is good for the economy and good for the earth.

Last week, we debated the EPA's proposed carbon limits on the House Floor. Some called into question whether CCS was adequately demonstrated because the technology is not commercially available. There is a difference between the two. The legal requirement is "adequately demonstrated," and the EPA has met that burden.

Let me close by saying that I know many of my colleagues across the aisle are skeptical about whether humans contribute to climate change. But the scientists, overwhelmingly, are not. And my constituents are not, and indeed they are seeing the impacts of climate change and asking policymakers to act. This winter's reduced snowpack not only means a shorter ski season and less of an economic boost from tourism, but it means less water for agriculture and salmon migration this spring and summer. The acidity of the Pacific Ocean is increasing, putting Oregon's fisheries and shellfish industries at risk. Warmer temperatures are leading to increased outbreaks of the mountain pine beetle, harming the Northwest's forest industry. And warmer temperatures are making it more challenging to grow our region's famous Pinot Noir grapes, a big part of the economy in Oregon.

So the impacts are real and we must do all that we can to mitigate the effects of climate change. The carbon dioxide we release now will affect generations to come. I am supportive of the Administration's efforts to transition the United States to a lower-carbon economy, and the EPA's proposed rule for new power plants is a critical step in that direction.

Thank you. I yield back, Mr. Chairman.

[The prepared statement of Ms. Bonamici follows:]

PREPARED STATEMENT OF ENVIRONMENT SUBCOMMITTEE RANKING MEMBER SUZANNE BONAMICI

Thank you, Mr. Chairman, and thanks to the Chair of the Energy Subcommittee, Ms. Lummis, for holding this morning's hearing.

Today we will discuss the performance standards proposed by the Environmental Protection Agency (EPA) for carbon dioxide emitted from new power plants. This hearing is similar to a hearing we held last fall, but this time we have the opportunity to hear directly from EPA on this important issue. I'd like to thank Acting Assistant Administrator Janet McCabe for being here today. I'd also like to thank the witnesses on our first panel for their thoughtful testimony.

Last year, President Obama laid out his agenda to address one of the biggest environmental challenges of our time-climate change. A key component of that plan, and any effort to reduce the amount of carbon emitted by the United States, is the need to significantly lower the amount of carbon produced during electricity generation. Emissions from power plants represent about one-third of the greenhouse gases produced by the United States, and EPA's proposed rule takes an important first step in tackling this major source of carbon pollution.

To emphasize—the proposed rule sets carbon limits on new power plants, not existing plants or those under construction. Looking at current and future market conditions, especially competitive natural gas prices, it is likely that many if not most new power plants will be able to meet the proposed carbon limits. It's the market, not the proposed rule, that is contributing to the proliferation of natural gas power plants over coal. In my home state of Oregon, our last coal plant is scheduled to be closed by 2020, and some of that generation capacity will be replaced with a natural gas plant.

The proposed EPA rule will create a market incentive for the continued development and promotion of carbon capture and storage, or CCS, technologies. The advancement of CCS technologies is essential if new coal power plants are to operate in the low carbon future we must achieve. I also want to point out that when EPA determines the "best system of emission reduction," it is actually legally required to promote the development of technology. I am sure we will hear much more on the state of CCS technologies from today's witnesses. That technology development is good for the economy and the earth.

Last week, we debated the EPA's proposed carbon limits on the House floor. Some called into question whether CCS was "adequately demonstrated" because the technology is not commercially available. There is a difference between the two. The legal requirement is "adequately demonstrated," and the EPA has met that burden.

Let me close by saying that I know many of my colleagues across the aisle are skeptical about whether humans contribute to climate change. But the scientists, overwhelmingly, are not. And my constituents are not, and indeed they are seeing the impacts of climate change now and asking policymakers to act. This winter's reduced snowpack not only means a shorter ski-season and less of an economic boost from tourism, but it means less water for agriculture and salmon migration this spring and summer. The acidity of the Pacific Ocean is increasing, putting Oregon's fisheries and shellfish industries at risk. Warmer temperatures are leading to increased outbreaks of the mountain pine beetle, harming the Northwest's forest industry. Warmer temperatures are making it more challenging to grow our region's famous Pinot Noir grapes.

The impacts are real and we must do all that we can to mitigate the effects of climate change. The carbon dioxide we release now will affect generations to come.

I am supportive of the Administration's efforts to transition the United States to a low carbon economy. The EPA's proposed rule for new power plants is a critical step in that direction.Thank you and I yield back.

Chairman SCHWEIKERT. Thank you, Ms. Bonamici.

Mr. Swalwell.

Mr. SWALWELL. Thank you, Chair, and thank you for holding this hearing today, and I agree with my colleague, Ms. Bonamici: global climate change is one of the greatest challenges of our time, and last September the Intergovernmental Panel on Climate Change released a report which states with 95 percent certainty that human activities are indeed responsible for climate change, and this report was based on a rigorous review of thousands of scientific papers published by over 800 of the world's top scientists. And this report makes it clear that if we don't take steps now, if we don't take steps today to halt what is causing climate change, the repercussions for humans and the environment will be catastrophic.

And the problem, as I see it, is that right now too few recognize that this is happening. I was giving a college lecture just 2 nights ago, and a student asked me, well, isn't it that Republicans think climate change isn't happening and Democrats think climate change is happening and it is caused by mankind, and I told the student, I look at this as I would look at my cases when I was a prosecutor, and as a prosecutor, if I was proving a homicide and I had DNA evidence, I wouldn't sit in a witness chair and testify, I would call an expert DNA analyst to the witness chair and that expert, based on that expert's training and experience and education, would tell the jury that indeed the DNA evidence was present and relevant, he is qualified as an expert. And here as I look at it with climate change, it is no different. We have called in the experts, and the experts are Republican scientists and the experts are Democratic scientists, and they have reached a bipartisan, nonpartisan, actually, conclusion, which is that humans are affecting climate change, and I think the sooner we all agree on that, the sooner we all sing off of the same sheet of music, the better off we will be and the better suited we will be to address what we can actually do to reduce its impact.

And so I have repeatedly said on this Committee that I am for an all-of-the-above approach to energy production as we transition to clean energy technologies, but I have also made it clear that this all-of-the-above approach we must make sure that we are taking steps to reduce our greenhouse gas emissions and lessening their impact on human health, the environment, and global climate.

And so I want reinforce also that the proposed standards going forward are only for new plants that may be built and are not intended and will have no effect on existing plants, so we are not going to see a wave of shuttered plants and massive layoffs as a result of their implementation. So again, I want to repeat this for folks in the coal industry who rightfully may be fearful of what this means. These regulations from the EPA are for future plants, not for existing plants. And there are in-depth discussions underway right now about establishing standards for existing plants, which the EPA currently plans to produce in June, but there is an ongoing, extensive engagement with all the stakeholders to make sure that those standards will be flexible and won't have negative effects on state economies and job creation.

So my colleagues on the other side of the aisle often talk, and I think for good reason, about not wanting to saddle our children with our national debt, and for that same reason, that same principle, I think we want to make sure that we do not saddle our children with the effects of climate change. So I am interested in what this hearing produces and what our witnesses have to say about carbon sequestration and what we can do to address climate change.

And with that, I yield back.

[The prepared statement of Mr. Swalwell follows:]

PREPARED STATEMENT OF ENERGY SUBCOMMITTEE RANKING MEMBER ERIC SWALWELL

Thank you Chairman Stewart and Chairman Lummis for holding this hearing, and I also want to thank the witnesses for their testimony and for being here today.

Global climate change is one of the greatest challenges that we face. Last September, the Intergovernmental Panel on Climate Change released a report which states with 95 percent certainty that human activities are responsible for climate change. This report was based on a rigorous review of thousands of scientific papers published by over 800 of the world's top scientists. The report also makes it clear that if we don't take steps to halt this change, the repercussions for humans and the environment will be catastrophic. We now need to move forward and take the necessary steps to combat the warming of our planet before these impacts become inevitable.

We know that humans are impacting the climate in a number of ways—through emissions from the vehicles we drive, deforestation, and changes in agricultural practices among other things.But electricity generation is the biggest producer of greenhouse gasses, accounting for roughly a third of our total emissions.

I have repeatedly said that I am for an "all of the above" approach to energy production as we transition to clean energy technologies. But I have also made it clear that, as part of this "all of the above" approach, we must take steps to ensure that we are reducing greenhouse gas emissions and lessening their impact on human health, the environment, and the global climate.

That is exactly what the proposed standards for new coal and natural gas burning plants aim to do, which is why I support their implementation. And, like Ms. Bonamici, I want to reinforce that these are only proposed standards for any new plants that may be built and will have no effect on existing plants, so we aren't going to see a wave of shuttered plants and massive layoffs as a result of their implementation. There are in-depth discussions underway about establishing standards for existing plants, which the EPA currently plans to propose in June, and there is ongoing, extensive engagement with all stakeholders to make sure that those standards will be flexible and won't have negative effects on state economies and job creation.

It has been my hope that Congress would act on this issue immediately. Unfortunately, too many of my colleagues choose to ignore the scientific consensus that human beings are playing a significant role in the warming of our planet, so I'm not expecting that much will be done legislatively to sufficiently address this issue anytime soon. The President has made it clear that, in the absence of Congressional action, his Administration is going to take the lead in efforts to reduce greenhouse gas emissions. These proposed standards reflect that commitment, and I fully support the President in this effort.

My colleagues on the other side of the aisle often say that our children and grandchildren are going to be left holding the bag if we don't reduce our deficits and the national debt, and I agree that it would be irresponsible of us not to take serious steps to put our fiscal house in order. Similarly, future generations will be the ones who will suffer if we don't take immediate and meaningful steps to confront climate change, and in this case—as the global scientific community has made clear again and again—the consequences of our inaction could be far more severe.

With that I yield back the balance of my time.

Chairman SCHWEIKERT. Thank you, Eric—I mean, excuse me, Mr. Chairman—or excuse me, Ranking Member, and let us hope it stays that way.

Chairwoman Lummis.

Mrs. LUMMIS. Thank you Mr. Chairman. I want to congratulate you on your new position on the Committee, and I look forward to working with you through the rest of this year. Our Environment and Energy Subcommittee joint hearings should be interesting, and I am happy to have you on board.

Last fall, the Science Committee held a similar hearing on the status of technology for carbon capture and storage. It was confirmed that CCS is not operating in any commercial-scale power plant in the United States and thus should not be considered adequately demonstrated technology under EPA's New Source Performance Standards.

Today we will also discuss the transportation and storage of captured carbon and what viable solutions currently exist for industry. I look forward to the hearing and hearing from EPA witness as well on the storage options under the proposed NSPS. Is recycling carbon in enhanced oil recovery possible on a large scale or will untested long-term geological sequestration be needed?

The EPA has implied that the rule does not need to speak to the issue of sequestration, that the cost and feasibly of carbon storage is outside the scope of their rulemaking. Staying silent on the last steps of the process proves the lack of demonstrated commercial viability.

Instead of focusing on real solutions, the EPA assumes this proposed rule will result in negligible CO_2 emissions changes, quantified benefits, and costs by 2022. Since it effectively bans the building of new coal plants, it has no impact.

The EPA is ignoring the consequences of their rulemaking to instead set a legal precedent for mandating unproven technologies. They need to go back and assess the impacts of this rule on non-air issues. There is no science behind the de facto mandated storage requirement. This is a policy of picking winners and losers through environmental regulations. New natural gas-fired units, boilers and heaters and existing plant standards are next. We need to see an all-of-the-above energy policy, not one based purely on politics.

I look forward to hearing from this first panel of witnesses on the larger effects of this rulemaking to the energy supply chain from research to delivery. I thank you for joining us.

I might also comment that in my State of Wyoming, in Gillette, Wyoming, the Neil Simpson coal-fired power unit will be shut down on March 21st, just in about 10 days. That is a unit that is only shutting down because of EPA regulations on industrial boiler MACT. The maximum obtainable control technologies don't exist to allow that boiler to continue through its remaining useful life of ten years, so it is going to be shut down. They are going to run it right up until the day that the EPA rules take effect because it is the most economical way to deliver affordable energy to the consumers it serves. It will be replaced by something more expensive. So rather than allowing it to continue through its useful economic life, it is being retired. It will be disassembled. It will be moved to another country. It will be reassembled and burn in another country. This is not sound policy.

So I am looking forward to hearing what sound policy that we can derive as a result of EPA's work.

Thank you, Mr. Chairman, and thank you, panel, for joining us.

[The prepared statement of Mrs. Lummis follows:]

PREPARED STATEMENT OF ENERGY SUBCOMMITTEE CHAIRMAN CYNTHIA LUMMIS

Thank you Chairman Schweikert. I want to congratulate you on your new position on the Committee and look forward to continuing our work through environment and energy Subcommittee joint hearings this year.

Last fall, the Science Committee held a similar hearing on the status of technology for Carbon Capture and Storage. It was confirmed that CCS is not operating in any commercial scale power plant in the U.S. and thus should not be considered adequately demonstrated technology under EPA's New Source Performance Standards (NSPS).

Today we will also discuss the transportation and storage of captured carbon and what viable solutions currently exist for industry. I look forward to hearing from the EPA witness on the storage options under the proposed NSPS. Is recycling carbon in enhanced oil recovery (EOR) possible on a large scale or will untested long-term geological sequestration be needed?

The EPA has implied that the rule does not need to speak to the issue of sequestration—that the cost and feasibly of carbon storage is outside the scope of their rulemaking. Staying silent on the last steps of the process proves the lack of demonstrated commercial viability.

Instead of focusing or real solutions, the EPA assumes "this proposed rule will result in negligible CO2 emissions changes, quantified benefits, and costs by 2022." Since it effectively bans the building of new coal plants, it has no impact.

The EPA is ignoring the consequences of their rulemaking to instead set a legal precedent for mandating unproven technologies. They need to go back and assess the impacts of this rule on non-air issues—there is no science behind the "de facto" mandated storage requirement.

This is a policy of picking winners and losers through environmental regulations. New natural gas fired units, boilers and heaters and existing plant standards are next. We need to see an all-of-the-above energy policy, not one based purely on politics.

I look forward to hearing from this first panel of witnesses on the larger effects of this rulemaking to the energy supply chain—from research to delivery. Thank you for joining us.

Chairman SCHWEIKERT. Thank you, Chairwoman Lummis.

If any of the Members wish to submit additional opening statements, your statements will be added to the record at this point, and I believe you can do that for—in this Committee, it is seven days? Or two weeks. to be able to add an opening statement.

[The prepared statement of Ms. Johnson follows:]

PREPARED STATEMENT OF FULL COMMITTEE RANKING MEMBER EDDIE BERNICE JOHNSON

Thank you Mr. Chairman. I am pleased that we will be able to hear testimony on this very important topic, and I want to thank the witnesses for appearing before us today.

Our climate is changing. These changes are resulting in more extreme weather, rising sea levels, and altered food webs. We must accept these new climate realities and be open to solutions if we are at all serious about protecting the health of American families. So I am happy to join my colleagues Ms. Bonamici and Mr. Swalwell in expressing my approval of the steps being taken by the Administration and by EPA, to advance clean energy technologies and protect future generations from the harmful effects of carbon pollution.

Throughout history industry has often resisted addressing environmental problems that emerge from a greater scientific understanding of how human activities impact the environment and our health. And in many of these cases, industry simply refuses to act without regulatory intervention and proper government oversight. The technology which we are discussing today, carbon capture and storage, or CCS technology, is an example of the type of innovative solutions that will not be implemented without a regulatory incentive to lower the amount carbon being emitted.

I, like many of my colleagues, wish that Congress would enact legislation to address climate change. Unfortunately, the current political realities will not allow us to act. So I say let us not stand in the way of EPA and necessary change. Let the Administration continue to move us forward, so that the U.S. can be a leader and we as Americans can do what we always do—rise to the challenge and move with great purpose to solve this crisis. I challenge industry to be leaders, and be a helpful partner in reducing our carbon emissions going forward.

I look forward to the testimony of our witnesses. Thank you again, and I yield back the balance of my time.

Chairman SCHWEIKERT. Having read all of your statements, you are all very, very bright and you are very smart. I will beg of you as we go through this hearing, I see this is a technical hearing, help us raise our level of technical understanding of this technology. And so instead it is less policy, it is more math and science, shall we say.

Our first witness is David Hawkins, Director of Climate Change Programs at the Natural Resource Defense Council. He joined NRDC in 1971 as one of the organizers' first staff members. In 1977, Mr. Hawkins was appointed to be the Assistant Administrator for Air, Noise and Radiation at EPA under the Carter Administration. In 1981, he returned to NRDC's Air and Energy Program, and in 2000 became director for NRDC's Climate Center. Instead of introducing everyone at once, I thought we will introduce each person as they get ready.

Mr. Hawkins, five minutes. And you know the routine: yellow light; talk faster.

TESTIMONY OF DAVID HAWKINS, DIRECTOR OF CLIMATE CHANGE PROGRAMS, NATURAL RESOURCES DEFENSE COUNCIL

Mr. HAWKINS. Thank you very much for inviting me to testify on behalf of NRDC. Several points I would like to make.

First, as numerous scientific and industrial organizations have concluded, we have to act with urgency to bring low-carbon electricity resources to market. We can't protect the climate without them.

Second, the Clean Air Act, passed by a bipartisan vote and signed by President Nixon, calls on EPA to set standards for pollutants like CO_2 that present a danger to health and welfare. Now, Congress did not give EPA free rein in setting these standards but it did not tie EPA's hands either.

The Act sets sensible limits on EPA's authority for these standards. First, EPA must show that the technology is available that could be applied to meet the proposed standards, and second, it must show that the cost of meeting those standards is reasonable. The EPA proposal is on solid ground legally and technically in the standards for new coal plants that it has proposed based on the capability of carbon capture and storage, or CCS, because in writing the Act, you did not require that EPA must point to a technology that is already in use in the regulated industry. To have done so would have been to put the polluters in charge of deciding whether they would ever have to clean up. Instead, the law directs EPA to survey approaches that can work in a given sector, even if there is little or no current use of those approaches in the category that is being regulated, and that is a commonsense approach.

As my testimony details, carbon capture and storage is proven technology at industrial scale with decades of experience for each of the component processes. Even without a standard in place, there are several vendors who are already offering commercial carbon capture systems and pipeline transport and geologic storage of CO_2 is fully commercial. EPA in its record has established a substantial body of evidence to support its technology conclusions, and the courts will review those conclusions when they consider challenges to the rule.

Turning to costs, EPA conducted a comprehensive analysis using Department of Energy research and concluded that the cost of making electricity at a new coal plant with CCS would fall in the range of the costs for new nuclear or biomass energy plants. Now, compared to production costs of a new coal plant with CCS to a new coal plant without CCS, the costs of the plant with CCS as EPA found would be about 20 percent higher, and that is without considering any revenues for enhanced oil recovery. But customer rate impacts would be much less than 20 percent, and that is because the cost of any given single unit is diluted by being folded into the rate base for that system.

Now, some in the coal industry and some owners of coal plants are lobbying Congress to intervene and try to block EPA's standards. This would be profoundly bad policy. If we prevent EPA from setting sound standards, that will not allow us to escape the threat of climate disruption. That will continue no matter what laws Congress tries to enact. Instead, it would perpetuate uncertainty about what investments should be made in the power sector. Investors who are asked to commit billions of dollars to a new power plant will not believe that a Congressional bar on action by EPA, in the very unlikely event that such legislation were signed into law, will be a stable basis for making those billions of dollars of investments. New coal plants take ten years to build and another 15 or 20 years to earn their investment back in the best of times, and if you believe that there are investors out there that are willing to take the risk that no limits on carbon pollution will be forthcoming during that long period of time, I suggest you hold another hearing and invite them to testify.

My advice to Members of Congress who are genuinely interested in creating space for coal to play a continuing role in the American economy would be to reject these efforts to hamstring EPA and instead support efforts that could enjoy bipartisan support to provide financial incentives for CCS used for enhanced oil recovery, for example. NRDC is on record supporting those kinds of initiatives, and we would be happy to work with Members that are interested in pursuing that approach to this important problem.

Thank you very much.

[The prepared statement of Mr. Hawkins follows:]

BEFORE

the

**SUBCOMMITTEE ON ENVIRONMENT
AND THE SUBCOMMITEE ON ENERGY**

of the

**HOUSE COMMITTEE ON SCIENCE,
SPACE AND TECHNOLOGY**

on

**EPA'S PROPOSED
NEW SOURCE PERFORMANCE STANDARDS
FOR CARBON DIOXIDE
FOR ELECTRIC GENERATING UNITS**

**TESTIMONY
OF
DAVID G. HAWKINS,**

**DIRECTOR, CLIMATE PROGRAMS,
NATURAL RESOURCES DEFENSE COUNCIL**

MARCH 12, 2014

Summary

The United States and other large carbon-polluting nations urgently need to take sensible steps to create an affordable, reliable energy system that is compatible with protecting the climate.

The Clean Air Act, passed by Congress more than 40 years ago, allows EPA to set reasonable standards that can cut harmful carbon pollution. EPA has already adopted successful carbon pollution standards from cars and trucks, the second largest source of U.S. carbon pollution.

EPA has proposed standards for new coal plants that are based on carbon capture technology, which has been proven through use on other large industrial categories. Partial carbon capture can easily achieve EPA's proposed standard with costs that are within the range of alternative investments for new plant owners who may be considering options other than natural gas combined-cycle plants.

Carbon capture systems have three components, each of which has been operated in large-scale commercial use for decades: separation of carbon dioxide (CO_2) from industrial gas streams; compression and transport of captured CO_2 by pipeline; injection of compressed CO_2 into geologic formations capable of retaining the gas until it has been converted through natural processes into a harmless mineral. EPA's assessment of the technical feasibility and economic reasonableness of the proposed standards rests on ample evidence and is fully consistent with the requirements of the laws Congress has written and the courts' interpretation of those laws.

Efforts to block EPA's sensible carbon pollution safeguards are bad policy. They would result not only in increased threats to human health and the environment; they would also reduce the prospects for developing and marketing carbon capture and storage systems that could be produced by American firms.

Chairmen and members of the Subcommittees, thank you for inviting me to present NRDC's views on the need for carbon pollution standards for fossil-fueled power plants and on the availability of technology to meet the standards recently proposed by the Environmental Protection Agency (EPA) under the Clean Air Act.

NRDC is a nonprofit organization with more than 400 scientists, lawyers and environmental specialists dedicated to protecting the environment and public health in the United States and internationally, with offices in New York, Washington D.C., Montana, Los Angeles, San Francisco, Chicago, and Beijing. Founded in 1970, NRDC uses law, science and the support of 1.4 million members and online activists to protect the planet's wildlife and natural environment, and to ensure a safe, healthy environment for all living things. NRDC's top institutional priority is curbing global warming and building a reliable, affordable and clean energy future.

We urgently need effective measures to cut dangerous carbon pollution from U.S. power plants and EPA is proceeding appropriately to use the authority Congress directed it to use in the Clean Air Act. Adopting sensible safeguards to cut carbon pollution is long overdue and must not be delayed longer.

Manmade "greenhouse gas" GHG pollution, including CO2, is disrupting the climate that has supported the rise of modern civilization over the past 20,000 years. If we do not act now to cut these harmful pollutants, we will lock in dangerous changes to our climate system that will result in death, disease and misery for billions of people over hundreds of years into the future.

Because our climate has been so stable for so many centuries, we tend to forget how much our well-being depends on that stability. All of our lives are built around the climate that has prevailed for millennia as our communities have been settled and expanded. Our daily existence depends on the smooth functioning of numerous energy, transport, water supply, and waste water systems that have cost trillions to put in place. Nearly all of these complex engineered systems have been designed and constructed based on assumptions that the climate of the past is a reliable predictor of the climate of the future. Thus, we have standards to design against the "100-year flood" for example. But we can no longer assume that the 100-year flood event of the past will be the 100-year flood of the future. Climate change rules out that assumption as a basis for prudent decision-making.

The potential threats of a disrupted climate for infrastructure are huge. Just last week, two major reports on the extent of these threats were released: one by the U.S. Government Accountability Office (GAO)[1] and one led by the Oak Ridge National Laboratory.[2] The GAO report documents that numerous components of our energy system (including drilling platforms, refineries, pipelines, barges, railways, storage tanks, power plants, power lines, and substations) are vulnerable to a range of climate change impacts. GAO notes that "impacts to infrastructure may also be amplified by a number of broad, systemic factors, including water scarcity, energy system interdependencies, increased electricity demand, and the compounding effects of multiple climate impacts."

The Oak Ridge report contains a number of findings underscoring the threats posed by climate change to infrastructure and urban areas:

"Regarding implications of climate change for infrastructures in the United States, we find that:

- Extreme weather events associated with climate change will increase disruptions of infrastructure services in some locations.
- A series of less extreme weather events associated with climate change, occurring in rapid succession, or severe weather events associated with other disruptive events may have similar effects.
- Disruptions of services in one infrastructure will almost always result in disruptions in one or more other infrastructures, especially in urban systems, triggering serious cross-sectoral cascading infrastructure system failures in some locations, at least for short periods of time
- These risks are greater for infrastructures that are:
    - Located in areas exposed to extreme weather events
    - Located at or near particularly climate-sensitive environmental features,

[1] U.S. G.A.O., "Climate Change – Energy Infrastructure Risks and Adaptation Efforts," GAO-14-74. http://www.gao.gov/assets/670/660558.pdf

[2] U.S. Department of Energy, "Climate Change and Infrastructure, Urban Systems, and Vulnerabilities," http://www.esd.ornl.gov/eess/Infrastructure.pdf

- such as coastlines, rivers, storm tracks, and vegetation in arid areas
- Already stressed by age and/or by demand levels that exceed what they were designed to deliver
- These risks are significantly greater if climate change is substantial rather than moderate

"Regarding implications of climate change for urban systems in the United States, we find that:

- Urban systems are vulnerable to extreme weather events that will become more intense, frequent, and/or longer-lasting with climate change
- Urban systems are vulnerable to climate change impacts on regional infrastructures on which they depend
- Urban systems and services will be affected by disruptions in relatively distant locations due to linkages through national infrastructure networks and the national economy
- Cascading system failures related to infrastructure interdependencies will increase threats to health and local economies in urban areas, especially in locations vulnerable to extreme weather events
- Such effects will be especially problematic for parts of the population that are more vulnerable because of limited coping capacities."[3]

The threats posed by a disrupted climate go far beyond impacts on infrastructure. They include adverse health impacts from disease, vectors, and heat stress. And they threaten food production through drought, floods, and disruption of pollinators.

Our political system may ignore these threats today but the natural systems we are disturbing will not pay attention to our politics. They will proceed to react to our continuing loading of the atmosphere with heat-trapping pollution, uninfluenced by any rationalizations we craft. More climate disruption will be locked in with every year that we fail to take it seriously.

Fortunately, the United States has the economic strength, technical know-how, and policy tools that can show the world we can address this threat in a manner that secures our economic future.

The Clean Air Act is one of those tools. In 2007 and again in 2011 the U.S. Supreme Court ruled that the Clean Air Act authorizes EPA to set sensible safeguards for CO2 and other GHG pollutants. EPA has already set GHG standards for new cars and trucks, with the cooperation of domestic and foreign

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[3] DOE report, note 2, at viii-ix.

manufacturers. EPA is now in the process of developing standards for the largest U.S. source of CO_2 pollution, fossil-fueled power plants.

Fossil-fueled power plants are also the largest CO_2 source globally. We cannot protect ourselves from the harms of a severely disrupted climate system unless we set effective standards to limit carbon pollution from these plants.

As you know, EPA has proposed, and reproposed, CO_2 standards for new natural gas and coal power plants. Under the Clean Air Act, EPA bases new source emission standards on the demonstrated capability of known technology, although source operators are free to use any approach they choose to meet the emission limits. Under the Act, EPA's standards must be based on a record that shows that two tests are met. First, the standards must be shown to be achievable using technologies that EPA has found to be demonstrated as technically feasible. Second, EPA must show that the costs of applying those technologies are reasonable. There are numerous cases interpreting these provisions in the context of previous New Source Performance Standards dating back to the early 1970s. As I will discuss, EPA's proposed CO_2 standards for new fossil plants are based on showings that are fully in accord with the Act and the prior court rulings interpreting it.

In its recent reproposal, EPA based the proposed standard for new coal plants on currently available systems that capture CO_2 from large industrial gas streams. Once captured, CO_2 is compressed and transported, typically via pipeline, to geologic formations, where it can be permanently isolated from the atmosphere, eventually being converted back into a mineral form.

As I will discuss in more detail below, all aspects of these carbon capture and storage (CCS) systems have been demonstrated at commercial scale industrial facilities for decades. They have operated reliably over multi-year periods to capture, transport, and safely dispose of millions of tons of CO_2. They can be readily applied at power plants, although until now, CCS has been used only to capture a fraction of CO2 emissions at about a dozen power plants, typically for sale to the food and beverage industry.

To date, the power sector has not used CCS broadly; but not because of any technical shortcomings. Rather, the sector has not applied CCS to full exhaust streams because of a policy failure. Up to now, there has been no national requirement to limit carbon pollution from power plants. CCS systems, like SO2 scrubbers, mercury controls, fine particulate controls, and nitrogen oxide controls, are not free. With rare exceptions, none of these other systems were used before there were regulatory requirements to control these pollutants. Congress wisely decided to give EPA the authority to impose clean air requirements to protect our health and welfare and this has resulted in trillions of dollars in benefits—exceeding compliance costs by a factor of 40 to 1.[4] Likewise, in the absence of any requirement to limit CO2 pollution from new or existing power plants, there has been simply no reason for owners and builders of power plants to install CCS systems.

Large coal-based power companies themselves have argued that they cannot finance CCS systems without federal CO2 standards. For example, in announcing the abandonment of a large-scale CCS project in 2011, the CEO of American Electric Power stated, "as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share."[5]

As with other control technologies, there are some rare pioneers for CCS. Currently several plants that will include CCS are either under construction or in the advanced pre-construction stage. Southern Company's new Kemper County, Mississippi coal plant and the refurbished coal plant at the Boundary Dam site in Canada are examples of CCS-equipped coal power projects nearing the end of construction.

[4] See EPA Benefits and Costs of Clean Air Act reports at http://www.epa.gov/air/sect812/index.html
[5] http://www.aep.com/newsroom/newsreleases/Default.aspx?id=1704

The Summit Power project in Texas and the Hydrogen Energy project in California are examples of CCS-equipped projects in the advanced pre-construction stages.

Yet some industry critics of EPA's power plant carbon pollution proposal have argued that EPA cannot base a standard on CCS because it has not been used commercially at full scale on existing power plants. Congress wisely did not create such a Catch-22 obstacle under the Clean Air Act. Since, in many instances pollution control technology is not used in a particular industry until it is required, Congress did not write the Clean Air Act to bar EPA from basing standards on technology that was not yet in use in a particular industry. The Clean Air Act, adopted with strong bipartisan support, sets forth a sound policy for cleaning up pollution from large new industrial sources. EPA is directed to set New Source Performance Standards, which are to be set at a level that EPA can show are achievable as a technical matter and at reasonable cost. The Act does not compel EPA to put on blinders and look only at the prevailing practice in the industry it is attempting to clean up.

The courts have upheld EPA's authority under the Clean Air Act to base New Source Performance Standards for a given industrial category on technologies whose performance has been demonstrated at other industrial categories.[6] This is a common sense policy. If the law allowed a particular industry to immunize itself from requirements to use available, feasible control technologies just by refusing to adopt them voluntarily, the industry would be put in full control of whether it would ever have to improve its performance.

EPA's Proposed CO2 NSPS for Power Plants

Turning to EPA's proposal for new power plants, the agency considered several options for new coal plant CO2 limits, ranging from no CCS, partial CCS, and full (90%+ capture) CCS. EPA selected partial CCS as the basis for the proposed standard, after considering both technical and cost issues. EPA found that

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

partial CCS was well demonstrated at relevant industrial scales and that when applied to coal power plants, partial CCS would have reasonable economic impacts.

As to technical feasibility, the record shows ample evidence to support the finding that CCS is a technically viable system for new coal-fired power plants. EPA has recently published a Technical Support Document that provides an expanded summary of the real-world experience with all three elements of a full CCS system: separation/capture of CO2 from industrial gas streams; compression and pipeline transport of CO2; and injection of CO2 into secure geologic formations.[7]

CO2 Capture

EPA 's January 2014 Technical Support Document (TSD) notes that industrial CO2 capture experience dates back to the 1930s. It explains that there are three types of capture systems applicable to power plants: post-combustion capture; pre-combustion capture; and oxy-combustion. In the power sector itself, there exist three types of real-world experience: commercial small-scale capture systems at existing coal-fired power plants; demonstration projects at power plants; and larger-scale projects now under construction or in advanced planning and development. EPA's TSD mentions two U.S. coal-power plants that use commercial amine scrubbers to capture CO2 for sale to the food and beverage industry.[8] These markets are so small that only a small portion of each plant's flue gas is passed through the scrubbing system. But the technology is proven and is scalable to sizes needed for a new plant to meet EPA's proposed standard. As EPA points out, engineering studies, the Boundary Dam coal plant in Canada, (where the CO2 capture system for a refurbished 110MW unit has been completed on budget—

[7] US EPA, Technical Support Document, Jan 8, 2014, http://1.usa.gov/1l2qV7x
[8] EPA TSD at 18.

other parts of the unit refurbishment experienced some cost overruns), as well as a plant being developed by NRG Energy in Texas, demonstrate the scalability of such post-combustion systems.[9]

As an example of pre-combustion capture operating experience, there is the Dakota Gasification Company's Great Plains Synfuels plant in North Dakota. This plant, which gasifies coal and produces pipeline gas (methane) and other chemicals, captures its CO2 and pipelines it for injection into an oil field in Canada. As we know, methane is an increasingly popular fuel for combined-cycle power plants. Were the pipes at the Great Plains plant connected to a combined-cycle power plant we would have a large-scale operating example of a power plant using fuel derived from coal, where CO2 capture was applied. There are no technical issues presented by the fact that the gas in those pipes currently is distributed in the general gas supply network rather than running to a gas-fired generating unit directly.

These examples alone are sufficient under the Clean Air Act to demonstrate that CO2 capture is technically feasible for new coal power plants.

Experts in the power industry confirm the technical viability of CO2 capture at large power plants. For example, Mississippi Power Company stated the following to the Mississippi Public Service Commission in 2009 in its application for approval of its large new coal plant in Kemper County, Mississippi:

> "a process referred to as Selexol™ is applied to remove the CO2 such that it is suitable for compression and delivery to the sequestration and EOR process. ... The carbon capture equipment and processes proposed in this Project have been in commercial use in the chemical industry for decades and pose little technology risk."[10]

In elaborating on the viability of CO2 capture for this plant, the Vice President of Mississippi Power Company testified to the Commission as follows:

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[9] TSD at 18-19.

[10] Kemper County IGCC Certificate Filing at 18, MPSC Docket No. 2009-UA-0014. Filed, December 7, 2009. http://bit.ly/1dt3eUr

"The carbon capture process being utilized for the Kemper County ICGC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over forty years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable."[11]

Compression and Transport of CO2

There is no need to spend much time on this topic. It is beyond dispute that the technology to compress CO2 and transport it by pipeline in quantities pertinent to power plant operations is fully demonstrated, with decades of operational experience. As EPA's Technical Support Document notes, currently about 50 million metric tons of CO2 are transported annually in the U.S., through 3,600 miles of pipeline.[12] The sources of the CO2 do not include electric generating plants but that is immaterial to the question of the performance of this component of the CCS system.

Geologic Storage of CO2

The issue of whether large quantities of compressed CO2 can be safely placed for long-term storage in geologic formations is an important one and one which was a matter of substantial concern for me personally when I first examined the issue of CCS starting in 1997. I have devoted a considerable amount of time since then studying the literature and discussing the topic with a broad range of geologists. I also participated in a reviewer capacity in the IPCC's 2005 Special Report on Carbon Capture and Storage.[13]

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[11] Phase Two Direct Testimony of Thomas O. Anderson at 22. Filed, December 7, 2009. http://bit.ly/1g1lHs0 . Additional examples of commercial offerings can be found in the Appendix attached to this testimony.

[12] EPA TSD at 25.

[13] IPCC, 2005 - Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), Carbon Dioxide Capture and Storage,
Cambridge University Press, UK.

In my judgment, the IPCC and EPA are correct in concluding that large-scale geologic storage is technically viable as a means of isolating CO2 from the atmosphere until it is eventually converted into mineral form. The basics are easily understood: first one needs a formation of porous rock into which the compressed CO2 can be injected, at a depth sufficient to keep the CO2 in a compressed state; then because CO2 is less dense than the fluids in the injection zone, there needs to be an impermeable rock formation above the injection zone; finally, the impermeable rock formation needs to be free from faults, fractures, or well bores that could provide pathways to the surface or overlying water supplies. A number of surveys have documented that formations meeting these criteria are abundant in the United States. For example, a study by researchers at DOE's Pacific Northwest National Laboratory found that 95% of the largest CO2 emitters in the U.S. (nearly all of them coal power plants) are located within 50 miles of a candidate CO2 storage formation.[14]

There is substantial commercial industrial-scale experience with CO2 injection into geologic formations, both in the U.S. and internationally. Most of the injected CO2 has gone into U.S. oil fields for enhanced oil recovery (EOR) but there are also a number of large CO2 injection projects in operation at dedicated CO2 storage sites: under the North Sea, the Barents Sea, Algeria, and Australia.[15]

Costs

Under the Clean Air Act and court decisions interpreting it, NSPS standards are authorized if the costs of compliance are shown to not be "excessive" or "unreasonable."[16]

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[14] Dooley, J., et al. Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change; Joint Global Change Research Institute, Pacific Northwest National Laboratory: College Park, MD, May 2006, 2006; p 67. See also the U.S. Geological Survey Carbon Atlas: http://co2public.er.usgs.gov/viewer/

[15] This experience is detailed in EPA's TSD at 26-29.

[16] See citations in EPA's 2014 proposed rule at 79 FR 1464, Jan. 8, 2014.

EPA's cost analysis demonstrates that the costs of complying with the proposed CO2 standards easily meet these tests: while more costly than natural gas power options, the standards can be met at costs that fall in the range of other generating plant options that the industry is building or planning to build. EPA's cost assessment starts with the observation that under current and expected market conditions, new natural gas combined cycle (NGCC) power plants would typically have lower electricity production costs (levelized cost of electricity) than new coal units, even if no CCS were required for the coal unit. But EPA notes that there might be instances where factors other than electricity production costs might cause investors or regulators to choose to build a coal plant or other non-NGCC power plant. Accordingly, EPA compared the projected cost (using Department of Energy reports) of a coal unit with CCS to a coal unit without CCS and to other non-NGCC options, such as nuclear, biomass, and geothermal power plants.

In its analysis, EPA concludes the projected costs of a coal plant with partial CCS would range from $92 to $110 per Megawatt-hour (MWh). This projected cost falls in the range for other non-NGCC options of $80 to $130 per MWh. EPA also compares the cost of a new coal unit with *no CCS* to a coal unit with partial CCS, finding that applying partial CCS would increase the power production costs[17] compared to the no-CCS case by 20% -- from $92 per MWh to $110 per MWh, if the CCS project received no revenues from the sale of CO2 for enhanced oil recovery (EOR). If the income from CO2 sales for EOR were included, the net production cost from the new CCS-equipped unit would range from $88 to $96 per MWh, depending on the price received for the captured CO2.[18]

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[17] Power production costs are only a portion of a customer's bill. Typically, about 40% of the bill consists of transmission, distribution and administrative costs. Moreover, in most systems, any single new power plant is only a small part of the total generating fleet whose costs go into the customer rate base. Thus, the increase in a customer's rates will be smaller than the increase in production costs at a new power plant.

[18] US EPA, "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units," at 240.
http://www2.epa.gov/sites/production/files/201309/documents/20130920proposal.pdf

In sum, EPA's proposal for new coal plants is based on a careful review of industrial experience with large-scale CO2 capture technology. EPA has compared projected costs of a new coal unit applying partial CCS with several other generation options and concluded the additional power production costs are 20% or less. EPA found these costs to be reasonable, given the substantial reduction in emissions that partial CCS would achieve at a new coal unit and the importance of providing a policy framework to support the use of CCS if new coal units are built.

Efforts to Block EPA Carbon Pollution Standards

Unfortunately, there are continuing misguided efforts to block EPA from adopting sensible safeguards for dangerous carbon pollution from fossil power plants, most recently with House passage of Rep. Whitfield's bill (H.R. 3826) last week. From the perspective of coal advocates, the rationale for these attacks on the Clean Air Act appears to be that Congress can protect the volumes of coal consumed by the power sector by prohibiting EPA from setting any meaningful limits on carbon pollution from power plants. This tactic simply will not work.

A careful examination of the forces confronting the coal industry shows that handcuffing EPA cannot be a successful way to improve the lot of coal producers. Most U.S. coal use is in the power sector and the power sector has choices for the resources it uses. The bill passed by the House seems to ignore the obvious fact that power producers are not in business in order to burn coal. Their business interest is in cost-effectively supplying electricity resources; and their fuel and technology choices will be driven by market forces that together are much more powerful than the effects of Clean Air Act standards on power production prices.

The biggest drivers of the market's continuing shift away from coal in the power sector are –

- the comparatively lower costs of natural gas as a fuel,
- the comparatively lower capital costs of natural gas power plants,
- the expanded penetration of renewables like wind and solar,
- the success of demand side management in reducing both annual and peak demands for power,

- and the conviction in much of the investor community, that climate science and observed climate disruptions will lead to public demands for policies to limit carbon emissions, likely before investments in new or refurbished coal plants are recouped.

Ironically, the Whitfield bill would stop the improvement of the one technology that is essential if coal and natural gas are to continue to be a substantial energy resource: CCS. The bill cannot and will not do anything to deal with the fundamental issues facing the continued use of coal. If it became law (which it almost certainly will not), it would be at most only an anesthetic that might provide coal producers with some perceived short-term pain relief but at the cost of causing investors and government actors to turn their back on deploying CCS. This would leave the coal industry where it is today: unable and unwilling by itself to build CCS projects that provide cost-cutting practical experience at pertinent scales; and largely failing in its efforts to maintain sales to power sector customers who are increasingly not wedded to coal and thus quite apathetic about building CCS projects themselves.

Perhaps inadvertently, the bill essentially ensures that coal producers will have no chance of turning CCS into a real option for power sector investors. By telling coal producers' customers (power plant owners) that they can indefinitely avoid any meaningful EPA limits on carbon pollution by simply declining to pursue CCS projects, the bill eliminates any incentive for power producers to put their political and financial muscle into an effort to solve coal's carbon problem.

Indeed, if this bill were law, it would tell power plant owners that pursuing a CCS project would be against their narrow economic interests because it would speed the day when the handcuffs on EPA's authority would be removed.

Coal producers are profoundly wrong in betting that blocking the use of the Clean Air Act to deploy CCS would revive interest in coal as a new power plant option. The reality is that hamstringing EPA will not keep coal from continuing to lose market share in the U.S. Instead, it will cause the power sector to look elsewhere to hedge its bets against the implications of climate disruption. Some in the coal-producing sector may think one can deal with climate disruption by enacting laws decreeing that we shall ignore it. But based on my conversations with many leaders in the power sector, that is not a view shared by the people who will be deciding what investments to make in new and existing power systems.

Some claim that today there is a "war on coal," while others, considering the health and environmental costs inflicted by today's use of coal to make electricity, say it is a "war by coal." But these charges and countercharges will not get us where we need to go as a society. What all of us need, both coal promoters and coal critics, is a broader consensus on sensible steps we can take to put our energy system on a more sustainable course. I continue to believe that it is possible to forge a consensus that includes a role for coal, at least as our society transitions in an orderly manner to resources that will function reliably to power growth without disrupting the climate we depend on to sustain modern economies.

A bill passed by the House in 2009 demonstrates that it is possible to garner the support of many legislators far from "coal country" for policies that would give coal an opportunity to define a role for itself as a continuing part of the U.S. energy mix. That bill, authored by two Democrats from states not dependent on coal, included about $60 billion in financial support for deployment of CCS on coal-fueled power plants. It is worth noting as well, that many environmental organizations that believe coal use must be phased out quickly, nonetheless supported this legislation.

I am referring to the Waxman-Markey climate protection bill. It did not become law but it does stand as a reminder that it is possible to broaden political support among elected officials from around the country for policies that could in fact provide a pathway for coal to earn a continuing role as a significant U.S. energy resource.

The bill passed by the House last week would create a huge obstacle to reviving any potential consensus for incentives to deploy CCS. It is based on a fundamentally flawed strategy: that by barring EPA from considering practical, available technologies that can reduce power plant carbon pollution, Congress can spur new coal plant investments and keep old coal plants running indefinitely. Succeeding with this strategy would require investors, power company managers, and state utility regulators to deny both economic and climate risks.

A new coal plant without CCS is simply not equipped to manage the risks that it will face in the marketplace. Some coal producers may be able to persuade themselves that it makes sense to spend several billion dollars on a machine that will be the dirtiest new power option in the United States. But coal producers won't be building power plants. And the people who will be are not going to believe that this bill provides them a stable platform for investing billions in projects that won't even be on line for perhaps another decade. Power sector investors are increasingly learning from Wayne Gretzky: they are skating to where the puck will be, not where it is now. The Whitfield bill tries to tell them there is no puck and that just won't fly.

In sum, EPA's proposed carbon pollution standards are technically achievable and can be met at reasonable costs. The standards are essential to assure that coal-based power plants will be designed to be operable in a world where climate disruption demands that we minimize carbon pollution. Efforts to block EPA's Clean Air Act authority to cut carbon pollution are not just bad for public health and the environment. They are bad for America's economic future and for the prospects of making continued use of fossil fuels for power generation compatible with protecting the climate that human society depends on to thrive in the future.

APPENDIX:

COMMERCIAL OFFERINGS

PRE-COMBUSTION CAPTURE TECHNOLOGY

Selexol

The Selexol technology is a proven technology, licensed by UOP.

UOP Selexol™ Technology for Acid Gas Removal, © 2009 UOP LLC. All rights reserved.[19]

"Selexol Process Commercial Experience

- *Over 60+ operating units*
  - *[...]*
- *Multiple large units in engineering phase*
  - *[...]*

Selexol Process-Summary

- *The Selexol process is a proven licensed technology"*

"Phase Two Rebuttal Testimony Of Thomas O. Anderson On Behalf Of Mississippi Power Company Before The Mississippi Public Service Commission", Docket No. 2009-UA-0014[20]:

"[...] the market for carbon capture systems in synthesis gas stream applications is very mature. The Company is aware of at least 20 different CO2 control technologies that have been installed in over 250 industrial applications worldwide. Mr. Schlissel appears to have confused traditional coal plant technology where carbon capture would be "post-combustion," meaning the CO2 is removed from the flue-gas after it has been used in the production of electrical energy, with the Project's IGCC technology where the CO2 removal process will occur "pre-combustion," meaning the CO2 is removed from the gasifier's synthesis gas prior to being used to produce electrical energy. The CO2 capture market for pre-combustion synthesis gas applications is mature, robust and global."

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[19] http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1

[20] http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=246453

"Updated Design, Description and Cost of Kemper County IGCC Project", Mississippi Power Company, MPSC Docket No. 2009-UA-0014, Kemper County IGCC Certificate Filing, Filed Dec. 7, 2009[21]:

"In addition, a process referred to as Selexol™ is applied to remove the CO2 such that it is suitable for compression and delivery to the sequestration and EOR process. All of the CO2 capture systems are installed prior to combustion of the syngas in the gas turbines. Capturing CO2 pre-combustion is much more efficient and less costly than post-combustion. The carbon capture equipment and processes proposed in this Project have been in commercial use in the chemical industry for decades and pose little technology risk."

"The carbon capture process being utilized for the Kemper County ICGC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over forty years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable."

<u>Rectisol</u>

The process dates from 1955, and is commercially proven and guaranteed.

"Acid Gas Removal by the Rectisol® Wash Process", Chemical Industry Digest, June 2013[22]:

"Rectisol was developed jointly by Linde and Lurgi in the late 50's and both companies are owning the IP rights. Easy to operate, very reliable, extremely high on-stream factor"

Linde Engineering website[23]:

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[21] http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=245160

[22] http://www.linde-india.com/userfiles/image/2013_07_18_%20Rectisol%20Article%20in%20Chemical%20Industry%20Digest.pdf

[23] http://www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_processing_plants/rectisol_wash/index.html

"Rectisol can purify synthesis gas down to 0,1 vppm total sulfur (including COS) and CO2 in ppm range. Commercial scale RECTISOL wash units are operated worldwide for the purification of hydrogen, ammonia-, methanol syngas and the production of pure carbon monoxide and oxogases."

Hydrogen Energy International (a joint venture of BP and Rio Tinto) sought to develop a commercial CCS project with 90% carbon capture in California. In their feasibility study, they describe their assessment of the Rectisol process.

"HECA Feasibility Study, Report #23 – AGR Licensor Evaluation", February 7, 2010.[24]

"Key to the Licensors' success in meeting the minimum project requirements is their commercially proven experience. Both Licensors have over 50 Rectisol units in operations worldwide with extensive experience removing acid gas from syngas produced in both liquid and solid fuel gasifiers, including Shell and GE (Texaco) gasifiers. Both have designed nits with clean syngas specifications more stringent than HECA's hydrogen rich fuel gas specification for the manufacture of chemicals. Both have designed units to produce acid gas within the H2S concentrations specified by the HECA project from low rations of H2S/CO2 in the feed gas, and CO2 product streams with the HECA purity requirements. Both licensors do have different units in operation demonstrating each aspect of the product specification requirements.

Summit Power's Texas Clean Energy Project, a 40MWe gross IGCC project in Texas with 90% carbon capture will also use Rectisol.[25]

POST-COMBUSTION CAPTURE TECHNOLOGY

<u>Shell-Cansolv</u>

The small Canadian company, Cansolv developed a proprietary amine technology, and was bought up by Shell in Dec, 2008. Since then, Shell-Cansolv has expanded its capabilities and commercial offerings.[26] On CO2 capture in particular, **the company's website states that**[27]**:**

"[t]his patented technology is designed and guaranteed for bulk CO2 removal up to 90%"

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[24] http://www.cpuc.ca.gov/NR/rdonlyres/538A0BA6-F6C9-495D-B13B-1399E446CDEC/0/23AGRLicensorEvaluation7Feb2010.pdf

[25] http://www.netl.doe.gov/publications/proceedings/10/co2capture/presentations/thursday/Barry%20Cunningham-FE0002650.pdf

[26] http://www.shell.com/global/products-services/solutions-for-businesses/globalsolutions/shell-cansolv/shell-cansolv-solutions.html

[27] http://www.shell.com/global/products-services/solutions-for-businesses/globalsolutions/shell-cansolv/shell-cansolv-solutions/co2-capture.html

In September, 2013, Shell-Cansolv and French engineering, procurement and construction firm, Technip, announced[28]:

"an agreement to leverage their respective expertise in marketing an end-to-end solution for Carbon Capture and Sequestration (CCS) projects. The agreement enables both Technip and Shell Cansolv to offer a full chain of engineering, procurement and construction (EPC) services for a post-combustion CO2 capture project to the power generation industry. The collaboration between two industry leaders will see Shell Cansolv capitalize from Technip's experience in the design, construction, and management of large EPC projects and its commercial global footprint. This new cooperation will also expand Shell Cansolv's international reach by giving the company a platform to offer its CO2 capture technology in increased scope as well as to new markets."

According to DLA Piper[29], "Engineering, Procurement and Construction (EPC) contracts are the most common form of contract used to undertake construction works by the private sector on large-scale and complex infrastructure projects. Under an EPC contract, a contractor is obliged to deliver a complete facility to a developer who need only turn a key to start operating the facility, hence EPC contracts are sometimes called turnkey construction contracts. In addition to delivering a complete facility, the contractor must deliver that facility for a guaranteed price by a guaranteed date and it must perform to the specified level. Failure to comply with any requirements will usually result in the contractor incurring monetary liabilities."

Saskpower's Boundary Dam CCS project, which is currently under constructions, is using the Shell-Cansolv process. SNC Lavalin is the EPC contractor there, and has to deliver the following process guarantees described in **"Inside Boundary Dam, The Carbon Capture Technology At The Heart Of The World's Largest Post Combustion CCS Project"; Devin Shaw, Manager – Strategic CCS Projects, January 23rd, 2014[30]:**

- *"Steam Consumption*
- *CO2 Removed (delivered for compression)*
- *Electricity consumption on critical equipment*
- *Solvent(s) & chemical consumption"*

[28] http://www.technip.com/en/press/technip-and-shell-cansolv-strengthen-co2-capture-technology
[29] http://www.dlapiper.com/files/Publication/18413b26-49b8-490e-acc6-3ff54faa55d7/Presentation/PublicationAttachment/1205e08d-e585-479d-ac17-42135efaf044/epc-contracts-in-the-power-sector.pdf
[30] http://wyia.org/wp-content/uploads/2014/01/devin-shaw.pdf

Mitsubishi Heavy Industries KM CDR Process/KS-1 Amine Solvent

Mitsubishi Heavy Industries (MHI) developed the Kansai Mitsubishi Carbon Dioxide Recovery Process (KM CDR Process) for CO2 capture, which uses a proprietary hindered amine solvent, called KS-1. Commercial applications to date have been on fertilizer and chemical plants, with maximum capture capacity up to 450 tons per day (T/D). MHI has also developed a large-scale basic design package for a 3,000 metric T/D -single train capture unit.

According to MHI's website:

"[t]he package is now ready for delivery on demand under full commercial arrangements" for gas boilers.[31]

The KM CDR Process is used at Southern Company's Plant Barry coal-fired power plant in Mobile, Alabama. For the first stage of the project, 0.15 million tons of CO2 is being captured annually from a 25 MW slip stream. The captured CO2 is being sequestered in a saline reservoir at Denbury Resources' Citronelle Oil Field in Bucks, Alabama in partnership with the Southeast Regional Carbon Sequestration Partnership (SECARB).

"World's First Integrated CCS of Coal-fired Power Plant Emissions Begins"; Mitsubishi Heavy Industries America, Inc., Tuesday, September 18, 2012.[32]

"Through participation in the world's largest-scale CO2 capture project at Plant Barry, MHIA intends to show the high-level economic feasibility and reliability of MHIA's technology in the commercial-scale CO2 capture from coal-fired power plant flue gas, and looks to further its commercialization globally".

Econamine

"Fluor's Econamine FG Plus^{SM} Technology For CO2 Capture at Coal-Fired Power Plants"; Satish Reddy, Dennis Johnson, John Gilmartin; Presented at the Power Plant Air Pollutant Control "Mega" Symposium, August 25-28, 2008, Baltimore, Maryland.[33]

"Fluor's proprietary Econamine FG^{SM} technology is a proven, cost-effective process for the removal of CO2 from low-pressure, oxygen containing flue gas streams. The performance of the process has been successfully demonstrates on a commercial scale over the past 20 years.

Through rigorous laboratory and field tests, Fluor has made added several enhancement features to further reduce the process energy consumption. In conjunction with the Econamine FG^{SM} technology, these enhancement features are now available at the improved Econamine FG Plus^{SM} technology. Any

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[31] https://www.mhi.co.jp/en/products/detail/km-cdr_largeplant.html

[32] http://www.mitsubishitoday.com/ht/display/ArticleDetails/i/9454

[33] http://www.fluor.com/SiteCollectionDocuments/EFG_forCO2CaptureatCoal-FiredPowerPlants-PPAP_Aug2008.pdf

combination of these enhancement features can be assembled in a custom-fit solution to optimize each and every CO2 capture application. Furthermore, the Economine FG Plus^{SM} process offers an improved environmental signature and can be configured around tight area requirements.

Fluor has developed a pre-treatment process for applying EFG+ technology to coal fired power plants. The strategy consists of three options for polishing scrubbing and incorporates Fluor's experience in large FGD projects"

"Report to the Global CCS Institute, Final Front-End Engineering and Design Study Report"; Tenaska Trailblazer Partners, LLC, January, 2012.[34]

"Tenaska and Fluor achieved the goals of the CC Plant FEED study, resulting in:

- *A design which meets Tenaska and industry standards and notably so in the areas of safety (through incorporation of the findings from the hazard and operability study and air dispersion modeling) and environmental profile (through specification of the CO2 capture rate at and permitted air emissions in the design basis);*
- *Confirmation that the technology can be scaled up to a constructable design at commercial size through (1) process and discipline engineering design and computational fluid dynamics (CFD) analysis, (2) 3D model development, and (3) receipt of firm price quotes for large equipment;*
- *[...]*
- *Establishment of performance guarantees which, after the addition of an appropriate margin, were consistent with the expected performance in Fluor's indicative bid."*

[34] http://cdn.globalccsinstitute.com/sites/default/files/publications/32321/traiblazer-front-end-engineering-and-design-study-report-final.pdf

DAVID G. HAWKINS
Director, Climate Programs
Natural Resources Defense Council

David G. Hawkins began his work in "public interest" law upon graduation from Columbia University Law School in 1970. He joined the Natural Resources Defense Council's (NRDC) Washington, DC office in 1971 as one of the organization's first staff members.

In 1977, Mr. Hawkins was appointed by President Carter to be Assistant Administrator for Air, Noise, and Radiation at the Environmental Protection Agency. During his time at EPA, he was responsible for initiating major new programs under the 1977 Amendments to the Clean Air Act. With President Reagan's election in 1981, Mr. Hawkins returned to NRDC to co-direct NRDC's Clean Air Program.

In 1990, Mr. Hawkins became Director of NRDC's Air and Energy Program, and in 2000 he became the Director of NRDC's Climate Center. NRDC's climate work focuses on advancing policies and programs to reduce the pollution responsible for global warming. Mr. Hawkins has worked with Congress, the Executive Branch, and various members of the business community to design policies that will slow, stop and reduce the emissions of global warming pollution. Mr. Hawkins is recognized as an expert on advanced coal technologies and carbon dioxide capture and storage. He assumed his current position as Director, NRDC Climate Programs in 2011.

Mr. Hawkins currently serves on the boards of the Woods Hole Research Center, Resources for the Future and the Center for Clean Air Policy. He has previously served on the Board on Environmental and Energy Systems of the National Academy of Sciences and the U.S. Department of Energy's Climate Change Science Program Product Development Advisory Committee. Mr. Hawkins participated in the Intergovernmental Panel on Climate Change's Special Report on Carbon Dioxide Capture and Storage and in the IPCC's Fourth Assessment Report on climate change.

Mr. Hawkins is married with three children and lives in Connecticut.

Chairman SCHWEIKERT. Thank you for that.

Today's second witness is Mr. Robert Hilton, Vice President of Power Technologies for Government Affairs at Alstom Power, Inc. Mr. Hilton has been in the air pollution control field for over 30 years. In his current role, Mr. Hilton provides information and technical data on power technology to state and federal regulators. He holds 15 U.S. and foreign patents and has authored numerous technical publications.

Mr. Hilton, five minutes.

TESTIMONY OF ROBERT G. HILTON, VICE PRESIDENT, POWER TECHNOLOGIES FOR GOVERNMENT AFFAIRS, ALSTOM POWER INC.

Mr. HILTON. Good morning. I would like to thank the Chairman and the Chairwoman and the Ranking Member the opportunity to present this testimony.

Alstom is a global leader in the world of power generation, transmission and transportation infrastructure. We are a leader in the field of carbon capture, having completed work on four pilots and 10 pilot, validation and commercial-scale plants that are in operation, design and construction. These projects include both coal and gas.

It is critical to be at commercial scale to define the risk of offering the technology. This will define contractual conditions and standard commercial terms including multiple performance guarantees, reliability, availability and other contractual guarantees.

Finally, our customers would be reluctant to invest in carbon capture technologies that have not been demonstrated at full commercial scale. Based on these criteria, Alstom does not currently deem its technologies commercial, and to my knowledge, no one else is willing to offer this full suite of guarantees. I emphasize, however, that the technologies being developed by Alstom and others work.

Let us take a look at the Clean Air Act criteria for best system of emission reduction. As proposed by EPA, feasibility, looking at the projects they cited, Kemper is under construction and not demonstrated. Sask is under construction and not demonstrated. Summit, HECA, Parish haven't even started construction. AEP Mountaineer was only 2.3 percent of the plant gas stream and does not qualify as significant. Dakota Gasification is producer of natural gas and fertilizer plant and not a power plant. Four of the six projects are gasifiers and high-pressure technology not suited to pulverized coal or natural gas combined cycle plants, which are atmospheric pressure, which really represent 95 percent or more of the fleet. These atmospheric technologies are not operating at significant scale at any site.

Cost—Alstom cannot comment in detail on the status of projects proposed by other companies, but based on facts in the public domain, I am aware of no CCS projects that would be considered cost-competitive in today's energy economy. The five capture and sequestration projects cited in NSPS proposal all rely on either EOR or byproduct revenues and/or federal subsidies. EPA should consider the typical power plant, which will not have federal subsidies and will not likely have access to chemical and EOR revenues. EPA needs to recognize that both chemicals and EOR are niche opportunities.

Then next comes the size of CO_2 reductions. EPA admits in its rule that it will not achieve significant reductions; in fact, it will simply slow the rate of acceleration.

As far as technology goes, this regulation will essentially stop the development of CCS since the proposed regulation provides a significantly lower cost alternative, natural gas, to the application of CCS on coal. There is unlikely to be a market for at least ten years. Industry-based R&D based on return on investment will stop. One only needs to look at the slowing pace already reported by the GCCSI.

We differ with EPA on the notion that NSP regulations will spur development. Let us really look at the industry has done for the Clean Air Act. When they wanted to do particulate matter, the EPA had been—rather, industry had been doing precipitators and collectors since the 1920s. When they went to do sulfur dioxide, the first full-scale scrubbers were built in 1942. I personally worked on one in 1970. When the NOX SIP call came in 1999, we had been doing reduction technologies since the 1980s. When mercury came in 2010, the industry had been deploying these since the mid-1980s, and in this case, we actually worked with EPA to revise the rule.

NSPS is different. The issue we are now faced with is that industry did not in earnest begin work on CO_2 from atmospheric gases until the early 2000s. The technology is not fully developed and the regulation proposed is ahead of the technology. It should be noted that this is a larger, more complex and technically sophisticated technology compared to any of the others in the Clean Air Act.

With no new power generation being built, it is our view that this presents a real threat to the U.S. economy both in terms of employment and the industries that build and supply coal plants as well as the mining, transportation and maintaining the necessary technology leadership. The true state of the technology on conventional power plants is that today there have been a handful of small demos such as AEP's Mountaineer and Southern Company's Plant Barry on coal. There are two small pilots in Mongstad, Norway, on gas. EPA indicates it has done literature searches and reviews of other sources of information to determine all the components are available. However, an important point that EPA misses is that the true risk and the complex multistage process is in the integration of all of the processes.

Let me make just a couple of quick points on that. How does the capture process respond with generation load? How does it respond when it is slaved to the unit? There are others that I could go on and on technically. I also would point out that DOE has developed a comprehensive roadmap and timeline for the commercialization of CCS technologies, which points to general deployment in the 2020s. We would encourage EPA to look at that.

Finally, it is the issue of cost, and we do not believe in this market and our experience shows us that the public utility commissions, the regulators are trying to maintain lowest cost of electricity to ratepayers. It is highly unlikely that they are going to approve the development and/or deployment of CCS with coal when they can do it much cheaper with a natural gas plant.

Thank you.

[The prepared statement of Mr. Hilton follows:]

Testimony of Robert Hilton
Before the U.S. House of Representatives
Subcommittee on Environment and Subcommittee on Energy
Of the Committee on
Science, Space, and Technology
Hearing on **Science of Capture and Storage: Understanding EPA's Carbon Rules**

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March 12, 2014

Introduction

Good morning. My name is Robert Hilton. I hold the position of Vice President, Power Technologies for Government Affairs for Alstom. I would like to thank Chairman Schweikert and Chairwoman Lummis and Ranking Members Bonamici and Swalwell as well as the entire Subcommittees for this opportunity to address these key issues on Carbon Capture.

Alstom is a global leader in the world of power generation, transmission, and transportation infrastructure. We set the benchmark for innovative and environmentally friendly technologies. More than 50% of the power plants in the United States have Alstom equipment, 40% of the electricity in the US is dispatched over Alstom software, and 25% of the world's electricity is generated on Alstom equipment. Alstom has the world's largest service business devoted to the maintenance of power generation equipment and is the world's largest air quality control company.

Alstom employs more than 93,000 people in 100 countries, and had sales of $27 billion in 2012-2013. In the U.S., Alstom employs approximately 7,000 full time permanent employees in 45 states. That number virtually doubles when you include workers hired for specific projects.

Alstom has a broad portfolio of power generation technology options: including coal, oil, natural gas, wind (both on shore and off shore), and hydro, biomass, geothermal, solar and nuclear. Significant pillars of our program are rapid and successful deployment of non-CO_2 sources of generation, namely nuclear and renewables; reduced CO_2 emissions through more efficient generation; and the capture of CO_2 from fossil fuel powered generation (Carbon Capture and Storage (CCS)). Alstom invests approximately $1 billion annually in research and development with significant activities in the US.

Alstom is a leader in the field of Carbon Capture having completed work on four pilot or validation scale plants and with 10 pilots, validation, and commercial scale demonstration plants in operation, design, or construction worldwide.
These projects include both coal and gas generation facilities. Alstom is commercializing three first generation capture related technologies: chilled ammonia post combustion capture, advanced amine post combustion capture, and oxy-firing combustion technology. We also have second generation technologies in development like chemical looping (in cooperation with Department of Energy (DOE)) and regenerative calcium cycle.

Status of Carbon Capture Technology

My testimony today will address the status of the Carbon Capture portion of CCS as a full scale commercial technology.

Carbon Capture is, within the realm of innovation, no different than any other technology under development. It is required to move through progressive stages of development at consistently larger scale or size. This process has been shown over decades to be the best approach to ensure commercial success by meeting the high standards of our industry and providing the confidence and reliability required by the power industry and electricity consumers.

Alstom has taken each of its Carbon Capture related technologies from the bench level to small and then larger pilots, followed by validation scale demonstrations with the aim to finally reach commercial scale demonstration. To date, no Carbon Capture technologies have been deployed at commercial scale. Alstom has successfully taken several of its technologies through the validation scale demonstration. This stage is the proof of technology in real field conditions (or in this case actual power plant flue gas). It is at this point we can say confidently that the basic technology works.

However, the final stage to reach commercial status is to perform a demonstration at full commercial scale. There are several reasons for this requirement. It is critical to be at commercial scale to define the risk of offering the technology. This cannot be defined until the technology can be shown to work at full scale. This is the first opportunity that we have to work with the exact equipment in the exact operating conditions that will become the subject of contractual conditions when the technology is declared commercial and is offered under standard commercial terms including performance and other contractual guarantees. This also becomes the first opportunity to optimize the process and equipment to effect best performance and, very importantly, seek cost reduction. These too are required to define commercial contractual conditions. Finally, our customers would be reluctant to invest in Carbon Capture technologies that have not been demonstrated to full commercial scale.

Based on these criteria, Alstom does not currently deem its technologies for Carbon Capture commercial and, to my knowledge, there are no other technology suppliers globally that can meet this criteria or are willing to make a normal commercial contract for CCS at commercial scale. I emphasize however that the technologies being developed by Alstom and others work successfully.

Clean Air Act Definitions

The Clean Air Act defines four criteria for the application of BSER or Best System of Emission reduction – to coal or anything else. The criteria are supported in the draft Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) for carbon dioxide (CO2) emissions by project examples. My testimony reviews these examples as follows:

Feasibility- is the technology technically feasible?

Looking at the projects cited by EPA at the time of this writing: Kemper is under construction and not demonstrated (reference: Brian Toth presentation at the Coal Technology Symposium' held on March 5, 2014, in Washington D.C.); Sask is under construction and not demonstrated and has delayed start-up until July 2014 (reference: the Honorable Brad Wall, Premier of Saskatchewan at same symposium); TCEP/ Summit is not financed and hasn't started construction (reference: Sasha Meckler of Summit at the same symposium); HECA is not financed and has yet to start construction; NRG Parrish is has yet to start construction; AEP Mountaineer was only 2.3% of the plant gas stream and therefore should not qualify as significant as referenced in the rule making; Basin Electric/ Dakota Gasification is a producer of natural gas and a fertilizer plant - not a power plant. Four of the six projects are gasifiers and high pressure technology not suited to pulverized coal or NGCC (natural gas combined cycle) electricity producing plants (which are at atmospheric pressure). Alstom suggests this summary demonstrates the EPA referenced projects fail to meet the "technically feasible" criteria. These technologies are not operating at significant scale at any site as of the rule publication. We do not support mandating technology based on proposed projects (many of which may never be built). These facts lead to the conclusion that the technology is not "adequately demonstrated" to be feasible at full scale.

Cost - are costs reasonable?

Alstom cannot comment in detail about the status of projects proposed by other companies. But based on facts in the public domain I'm aware of no CCS projects that would be considered cost competitive in today's energy economy. The five carbon capture and sequestration projects cited in the NSPS proposal as examples for having met the cost criteria in the NSPS rule all either rely on EOR or by-product revenue, federal subsidy, or they will not economically dispatch. We would suggest that in setting economic criteria for technology, EPA consider the" typical commercial power plant which will not have federal subsidies and will likely not have access to chemical or EOR revenue. EPA needs to recognize that both chemicals and EOR are niche opportunities and not available to most power plants. In the case of EOR, it works only in proximity to oil fields that can be tapped with tertiary flooding and where pipelines exist to reach those fields; all are unique circumstances not available to the typical commercial power plant in the US.

Size of CO2 emission reductions:

EPA, in the rule, states that this rule will not achieve significant reductions in CO2 emissions.

Technology- will the system promote further development

As detailed below, this regulation will essentially stop the development of CCS. Without new coal plants, it is unlikely technology developers will continue to invest in CCS development. Since the proposed regulation provides a significantly lower cost alternative (NGCC without controls) to the application of CCS to coal, there is unlikely to be a market for at least 10 years, and most R&D cannot be sustained for that period. Industry bases R&D on market potential and return on investment. With no market in sight, investment will stop. One only need to look at slowing pace of private and public investment world-wide in CCS projects as shown in the annual survey of the Global Carbon Capture and Storage Institute (GCCSI), which results from economic conditions and lack of progress on climate change negotiations as proof that EPA's assumption are unrealistic.

We differ with EPA on the notion that these NSPS regulations will spur development of new technology (as required by Congress in the Clean Air Act).

Let us examine the history of the Clean Air Act (CAA). When the CAA was enacted, the first pollutant was particulate matter. Industry had been developing collectors and precipitators since the 1920's, so was well prepared. When EPA called for sulfur dioxide (Sox) control, the industry had built its first full-scale scrubbers in 1942 and was well prepared. I personally worked on my first full scale scrubber in 1970. When the nitrogen oxides (NOX) State Implementation Plan (SIP) call came in 1999, the industry had been deploying reduction technologies since the early 1980s. When mercury regulation came in 2010, the industry had been deploying mercury systems since the mid-1980s. And in the case of Mercury and Air Toxic Standards (MATS) the industry demonstrated that the originally proposed standards could not be met and worked with EPA to develop EPA's revised MATS standards.

NSPS is different. The issue we are now faced with is the industry did not in earnest begin work on capture of CO2 from atmospheric gases until 2000-2002. The technology is not fully developed and the regulation proposed is ahead of technology development. It should also be noted that carbon capture is much larger, complex and technically sophisticated compared with any of these previous technologies. From this history, we see that the CAA has been a **market driver** and **not a technology driver**. Industry has always moved to be prepared for the next environmental issue.

Clean Coal Power Initiative (CCPI) Projects

In the Energy Policy Act of 2005, Congress expressly prohibited EPA from basing any regulation on projects receiving CCPI money. EPA has defended its use of these projects to name partial capture on the word "solely." All of the current or proposed plants I'm aware of have received CCPI money except Basin Electric (not a power plant) and Sask (a Canadian project with equivalent Canadian funding). Similarly, none of the projects referenced in the regulation are designed for partial capture except Kemper.

Impacts on Electricity Consumers

The proposed regulations would force generators to move from coal to natural gas, which potentially could have major impact on electricity consumers.

Coal with CCS under current market conditions would not compete with natural gas without CCS due the extreme capital cost of the CCS equipment and additional operating cost as currently viewed by both generators and developers and even in DOE National Energy Technology Laboratory (NETL) studies. Thus, anyone building new generation would logically build Natural Gas Combined Cycle (NGCC) plants. However, let us look at the impact this regulation will have.

With no new coal power generation being built it's our view that this presents a real threat to the US economy both in terms of employment in the industries that build and supply materials for coal plants, as well as coal mining, transportation and maintaining the necessary skill sets to design, build and operate such plants through a period of 10 or more years of inactivity.

Coal has always been the fuel that balanced electric prices through price spikes of gas and other market conditions. It should be noted that while natural gas is currently low in price and abundant (and projected by EIA to remain so), dependence on gas this winter has driven consumers price spikes with electricity reaching $7000 per MWh due to infrastructure constraints on gas fuel supplies. This figure is sharply different than EPA's expected $70 per MWHr.

Similarly, reliance on EIA forecasts that no coal plants will be built in any event is precarious. EIA forecasts are a snapshot based on a set of assumptions and have consistently failed to see market fluctuations and interruptions. They are in fact revised annually and sometimes more frequently. We point to the EIA assumption of gas at $4.50 per mmBtu through the decade and prices have already risen in recent months to $5.50- 6.50 per mmBtu and sometimes higher.

Alstom is a leading global developer of carbon capture technology. The true state of the technology (setting aside 1-5MW pilots) is that today there has been one 40 MW capture unit at AEP's Mountaineer Plant (since shut down), one 35 MW capture plant at Southern Company's Plant Barry (still in operation) on coal; there are two small pilots in early development in Mongstad, Norway on natural gas and refinery gas. This is the essentially the extent of the largest current capture technology with sustained operation on conventional power plants. DOE is participating in a number of projects cited by EPA in its text which are about or nearly demonstration size that are all estimated to start between late 2014 and 2018. Alstom would point out the recent report by the Congressional Research Service (Carbon Capture and Sequestration (CCS): A Primer, Peter Folger, Specialist in Energy and Natural

Resources Policy; May 14, 2012), which calls into question whether all or any of these will become fully operational.

Alstom's view is that while carbon capture technology has been proven to work, the industry has yet to reach demonstration stages to reduce the cost and reduce the risk of scaling these technologies from pilot or validation scale to full scale. Thus Alstom would challenge EPA on the argument that Carbon Capture is available and adequately demonstrated. In our view without full scale demonstration, the technology should not be considered for deployment across the industry or for application as NSPS or best system of emission reduction as the industry is not in a position to make proper commercial warranties and guarantees as required...

Technology Scale-Up and Integration

EPA indicates it has done literature searches and reviewed other sources of information to determine that all the components of CCS are available. However, an important point EPA misses is that the true risk in any complex multi-stage process such as CCS is the scale-up and integration of the components. The risk is defined when at scale you need to deal with integration issues such as:

- How does the capture process turn down with generation load;
- What is the potential impact on generation if the capture plant is dependent of the steam load of the generator;
- What happens to compression when load on the capture plant is reduced and does that subsequently impact transportation or injection given instantaneous load drop and increase;
- How will volumes of water and byproducts from impurities in the flue gas be handled and will they effect injection; and

- What is the risk associated with shutting down generation when the capture or subsequent processes fail?

The list goes on but the point is these all create risks which need to be understood by scaling up and performing demonstrations. This has been reflected in the current market by two of the EPA projects having to be financed internally and with the generator accepting the risks (not normal in the power industry) and in two other projects where financing by US financial institutes does not exist and the projects have had to seek financing arrangements outside the US. This truly reflects that CCS is not ready to be mandated for deployment. EPA's arguments are similar to a statement that since all car components are known, everyone can build their own car and there is no need for companies that assemble and guarantee cars.

Customer Guarantees

Alstom would also point out that it is unaware that any supplier of this technology is ready or able to offer commercial guarantees for such full-scale systems of carbon capture. All utility generators require extensive performance guarantees and warranties which cannot be offered without proper demonstration at scale. All the projects that form a basis for the EPA rule would require extensive revenue sources from niche market opportunities like EOR and chemicals and large federal subsidies. None would stand alone on a common commercial basis. This would in turn mean that no new coal burning plant could be permitted or financed. Hence it is unlikely that such systems will be available prior to the EPA obligatory eight-year review of this proposed NSPS.

CCS Technology Roadmap

Alstom would also point out that DOE has developed a comprehensive roadmap and timeline for the commercialization of CCS technologies which ultimately points to general deployment around 2020; although the timeline for commercial deployment cannot be clearly defined until there is full scale demonstration. After the first generation technology has been demonstrated at scale, the hope is second generation technologies can reduce costs, although they will not have been demonstrated at that time. This timeline, if embraced by EPA, would set CCS aside until the EPA suggested eight-year review of NSPS, thus avoiding conflict between agency visions.

By simply requiring all technologies be the highest possible efficiency (such as Ultra Super Critical technology), this proposal would promote the policy of having the best available technologies to replace the older less efficient existing fleet. It also would be a good transition for the existing fleet. Alstom has estimated that using best efficient technology and then upgrading the existing fleet, the industry can combine to exceed proposed targets for reduction in CO2 prior to 2020 and the next NSPS review.

Alstom would also take one further exception to the position that this rule would incent the development of CCS. Our view of the market and industry is that public utility commissions and regulators are struggling to maintain the lowest cost of electricity to ratepayers. Consequently, in today's market of moderate natural gas prices, , it is very unlikely that any commission will allow the recovery of development costs on existing plants based on a new plant rule that allows uncontrolled natural gas alternatives that are obviously less expensive. Without the ability to find cost recovery or government subsidies, it will not be possible to reach demonstration scale critical to the successful adoption and application of the CCS technology by generators and gain acceptance by the financial community that are necessary to achieve significant carbon reductions..

In conclusion, we believe the failure to meet the Clean Air Act criteria should prompt EPA to reconsider crafting carbon control regulations more in line with the technology development and DOE timeline.

Thank you for the opportunity to present this testimony...

ALSTOM

CAREER PROFILE

Robert G. Hilton
Vice President,
Power Technologies for Government Affairs,
Alstom Power Inc.

In his current role, Robert (Bob) Hilton provides information and technical data on power technology to state and federal regulators. During more than ten years with Alstom, Bob has held several positions of increasing responsibility including Vice President of Marketing for Alstom's global Air Pollution Control business, Vice President of Research & Development in air pollution control; Vice President of Alstom's Post Combustion Carbon Capture Programs; Director of Business Development; and Strategic Development Director.

Today, Hilton is responsible for providing technical guidance on regulatory and legislative issues for Alstom and providing testimony to committees supporting Alstom's positions. He represents the Company in technical organizations, work groups and industry associations to process the Company's regulatory agenda and interfaces with state and federal officials to provide information on key issues. Additionally, Hilton provides guidance and input to the strategic and operational planning of the Alstom US business with regards to regulatory issues.

Hilton has been in the air pollution control field for over thirty years. His specialty is air pollution and the related issues of water and waste management. He holds a B.S. in Chemistry from Philadelphia College of Textiles and Science, a MBA in Finance, from Drexel University, Philadelphia and is past president and a member of the Board of Directors, Institute of Clean Air Companies. He is also the inventor of 15 US and foreign patents and applications and has authored numerous technical publications.

Chairman SCHWEIKERT. Thank you, Mr. Hilton.

Our third witness is Mr. Robert Trautz, Senior Technical Leader at the Electrical Power Research Institute. He has over 30 years of experience in research and applied geology and hydrology involving CO_2 storage. In his current capacity, Mr. Trautz manages demonstration projects funded by the Department of Energy, EPRI and other industry groups. Mr. Trautz has previously worked at Lawrence Berkley National Laboratory and the U.S. Geological Survey.

Mr. Trautz, five minutes.

TESTIMONY OF ROBERT C. TRAUTZ,
SENIOR PROJECT MANAGER,
ELECTRIC POWER RESEARCH INSTITUTE

Mr. TRAUTZ. Thank you very much, Mr. Chairman.

My name is Robert C. Trautz. I am a Senior Technical Leader at the Electric Power Research Institute. EPRI conducts research related to the generation, delivery and use of electricity for the benefit of the public. EPRI is working with the Southern States Energy Board within the Southeast Regional Carbon Sequestration Partnership program to assess CO_2 storage opportunities in the southeastern United States. My testimony reflects the independent views of EPRI and isn't defined by SSEB or SECARB.

At the heart of the proposed New Source Performance Standard is a mandatory reduction in CO_2 emission intensity using CCS technology that will require coal-fired power units to reduce CO_2 emissions to less than 1,100 pounds per megawatt-hour gross. To place EPA's emissions limit in perspective, the amount of CO_2 that will need to be stored to meet the limit is approximately 40 percent of the CO_2 output from a pulverized-coal plant. For a moderate-sized, 1,000-megawatt plant, this equates to about 3.1 million tons per year. Over a 40-year lifespan, for this example, the plant will need to store over 120 million metric tons of CO_2.

To understand the significance of storing this quantity of CO_2, I offer the following storage example for illustrative purposes only. Using the Lower Tuscaloosa Sandstone located within the Gulf Coast region of the United States, injection of 120 million tons of CO_2 into this regionally extensive saline reservoir would create a CO_2 plume with a subsurface area of several square miles. This example illustrates the importance of characterizing and utilizing large regional reservoirs for CO_2 storage due to the very large quantities of CO_2 that we are talking about for multiple plants.

The U.S. Department of Energy estimates there are approximately 226 billion metric tons of CO_2 storage capacity in depleted oil and gas reservoirs and up to 20 thousand billion metric tons in saline formations in the United States and Canada. The stark contrast in these storage estimates reflects the widespread distribution and importance of saline reservoirs. The potential use of depleted oil and gas reservoirs for CO_2 storage could be adversely affected by potential regulatory requirements associated with CO_2 storage. Preliminary feedback from oil producers indicates that a requirement for EOR operators to monitor and certify CO_2 storage under subpart RR of the EPA's mandatory greenhouse gas reporting requirements could be a risk that many companies may not be willing to take. Thus, such requirements may have the unintended consequence of discouraging the use of depleted oil and gas reservoirs. The limited geographic distribution and storage capacity of these reservoirs in any case will eventually limit their long-term use. One of the benefits of using depleted oil and gas reservoirs for CO_2 storage is the wealth of geologic knowledge available for these reservoirs. In contrast, little is known about saline reservoirs because they currently have little to no economic value. To date, there are only three large-scale saline storage projects in the world that have or are currently injecting CO_2 at a rate approaching 1 million metric tons per year. It is important to note that these projects involve CO_2 separation from natural gas and store an annual amount equal to about a third of the CO_2 from a single 1,000-megawatt power plant. From a geologic storage perspective, these projects are very important for the following reasons.

The Sleipner Project in the North Sea is the flagship of the global CO_2 saline storage project injecting CO_2 at a sustained rate of 1 million metric tons per year for nearly 20 years. The Snohvit Project in the Barents Sea is injecting at a rate of 820,000 metric tons per year. Initially, however, this project found that the formation permeability was too low and pressures climbed rapidly, requiring injection into a different zone. The In Salah Project in central Algeria suspended CO_2 injection in 2011 after monitoring data indicated that the lower caprock above the storage reservoir had likely fractured due to injection.

The projects illustrate the risks and geologic uncertainty associated with selecting a saline storage site. They also illustrate the need to gain experience at scales commensurate with full-scale commercial power projects. The DOE's field demonstration projects are invaluable because of their ever-increasing storage scale. However, given that the NSPS is clearly focused on reducing emissions from fossil fuel-fired plants, further government investment in research is needed that integrates power projects with capture and saline storage at full scale. Only two of the DOE demonstration projects fielded to date have included small-scale capture and saline storage on coal-fired units of less than 100,000 tons each, and only one large-scale, million-ton-per-year saline injection project is currently planned.

In addition, given that more is known about oil and natural gas reservoirs, future storage research and funding may need to focus more on saline reservoirs to help close the knowledge gap.

Thank you for the opportunity to testify before you today, and I welcome your questions.

[The prepared statement of Mr. Trautz follows:]

Testimony
Technology Requirements for Meeting the New Source Performance Standards for CO_2 from Electric Generating Units:

Technical Insights from EPRI on CO_2 Storage

U.S. House of Representatives
Committee on Science, Space and Technology
Subcommittee on Environment
Subcommittee on Energy

Robert C. Trautz
Senior Technical Leader
Electric Power Research Institute
March 12, 2013

My name is Robert C. Trautz. I am a Senior Technical Leader in the Generation Sector at the Electric Power Research Institute (EPRI, www.epri.com). EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public.

As an independent, nonprofit corporation, EPRI brings together its scientists and engineers, as well as experts from industry, academia, and government, to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy, and economic analyses to drive long-range research and development planning, and supports research in emerging technologies including Carbon Capture and Storage. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, California; Charlotte, North Carolina; Knoxville, Tennessee; Washington, D.C., and Lenox, Massachusetts.

EPRI is working closely with the U.S. Department of Energy and the Southern States Energy Board (SSEB) under the Southeast Regional Carbon Sequestration (SECARB) partnership program to assess CO_2 storage opportunities in the southeastern United States. It is with the support of the SSEB and SECARB partnership that I appear before you today

EPRI appreciates the opportunity to provide this testimony to the subcommittees..

Putting CO_2 Emissions and Storage into Perspective

The proposed rules for the New Source Performance Standard (NSPS) places limits on CO_2 emissions from new fossil fuel-fired electric generating units (EGUs) that will significantly reduce CO_2 emissions and will have a profound impact on technology used to generate electricity in the future. At the heart of the proposed EPA rule is a mandatory reduction in CO_2 emissions intensity using carbon capture and storage (CCS) technology that will require EGUs that use solid fossil fuels like coal to reduce CO_2 emissions to less than 1,100 lb/MW-hr gross. To place this emission limit in perspective, the amount of CO_2 that will need to be captured and stored to meet the 1,100 lb/MW-hr gross emission limit is approximately 40% of the CO_2 output from a supercritical pulverized coal fired EGU. A relatively modest size 1,000 MW EGU will produce approximately 7.8 million metric tons of CO_2 per year, requiring that about 3.1 million metric tons of CO_2 be captured and stored per annum. For this example, the total CO_2 tonnage to be stored over a 40 year EGU life span will exceed 120 million metric tons.

To understand the significance of storing this quantity of CO_2, I offer the following storage example for illustrative purposes only:

Using the Lower Tuscaloosa Massive Sandstone located within the Gulf Coast region of the United States as a case in point, which was studied by the SECARB partnership in 2008-2009 and found to be a significant potential storage reservoir,[1] injection of 120 million tons of CO_2

[1] Advanced Resources International, Inc., Final Report Plant Daniel Project: Closure Report, Vol. 1, Prepared for the United States Department of Energy, National Energy Technology Laboratory, January 31, 2010

into this 210 ft thick regionally extensive saline reservoir at a depth of 8,500 ft would create a CO_2 plume with an surface area of over seven square miles.

This example illustrates that the footprint or area in the subsurface occupied by the injected CO_2 emissions from a single EGU will likely extend over many square miles. It also demonstrates the importance of characterizing and utilizing large regional reservoirs for storage due to the very large quantities of CO_2 from multiple EGUs.

What types of reservoirs are available for storage and what are their primary attributes?

The testimony that follows is intended to provide a basic technical understanding of CO_2 storage and the potential role that saline and depleted oil and gas reservoirs will play in meeting the Nation's storage needs. Note that geologists typically know more about oil and natural gas reservoirs because of related oil and gas exploration and production activities, but a number of reservoir types will likely have to be utilized to meet expected storage needs.

Saline reservoirs represent deep rock formations consisting of porous sandstones, limestones, dolomites, and coals (to name just a few rock types that can serve as storage reservoirs) that contain naturally occurring saline groundwater that is non-potable. Oil and gas reservoirs typically consist of the same porous sedimentary rock and often contain saline groundwater too. This is because oil and gas reservoirs are typically part of a much larger regional saline aquifer system. Oil and gas reservoirs contain geologic traps, structural features like folds or faults in the earth, where oil and natural gas accumulate over geologic time. Reservoirs that contain natural traps represent the best storage reservoirs because they are likely to have high potential for retaining stored CO_2. "Depleted" oil and gas reservoirs refer to the fact that the reservoir has undergone production of oil and natural gas, resulting in the depletion or reduction in fluid pressure below initial reservoir conditions that occurs when oil and natural gas are extracted from the reservoir.

It is important to note that fluids, whether oil, natural gas, saline groundwater or CO_2, move through and occupy the voids or pore spaces in the rock. Earth scientists use the term formation or rock permeability to describe the ease at which fluids move through the rock pores. Porosity is an important property that describes how much space or pore volume is available in the rock to store fluids including CO_2. Sandstone formations with high permeability and high porosity make excellent storage reservoirs because it is easy to inject and store CO_2 in these formations. Rocks like mudstone and shale that have low permeability and low porosity make excellent caprocks, which keeps the CO_2 contained within the storage reservoir.

The Department of Energy estimates that there are approximately 226 billion metric tons of CO_2 storage capacity in depleted oil and gas fields and between 2,102 to 20,043 billion metric tons in saline formations in the US and Canada.[2] The stark contrast in these storage estimates illustrates the importance of saline reservoirs. The range of values provided for saline storage capacities reflects the fact that geologists don't know as much about these types of reservoirs and, therefore, the capacity values have greater uncertainty.

[2] Carbon Sequestration Atlas of the United States and Canada, 4th Ed., U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, 2012.

Depleted oil reservoirs that have undergone primary and secondary production are attractive targets for CO_2 storage for several reasons:

- They typically contain known traps that have stored oil for millennia if not millions of years. By analogy, they are expected to hold CO_2 for a similar geologic time scale
- The reservoirs are well characterized because of oil exploration activities; however, important reservoir properties (permeability and porosity) are typically known only for the oil-bearing layer
- Additional storage capacity is available due to the removal of oil and brine during production
- Reservoir pressures are typically lower than the original reservoir pressure, allowing more CO_2 to be injected at higher injection rates

Depleted gas reservoirs share many of the same attributes as depleted oil reservoirs, including the fact that the traps have stored natural gas over geologic time.

Depleted oil and gas reservoirs also create some challenges in that the numerous well penetrations in the oil and gas field create potential conduits for CO_2 migration and leakage into shallower zones if the wells are not properly plugged and abandoned.

The potential use of depleted oil and gas reservoirs for CO_2 storage could be adversely affected by potential regulatory requirements associated with CO_2 storage. Preliminary feedback from oil producers indicates that a requirement for EOR operators to monitor a storage facility and certify that the CO_2 is stored under Subpart RR of the EPA's mandatory greenhouse gas reporting program, could be a risk that companies may not be willing to accept. Thus, such requirements may have the unintended consequence of discouraging the use of depleted oil and gas reservoirs. It is apparent, however, that the limited geographic distribution and storage capacity of oil and gas reservoirs will, in any case, eventually limit their long-term use.

One of the benefits of using depleted oil and gas reservoirs for CO_2 storage is the wealth of geologic knowledge available for these reservoirs. In contrast, little is known about saline reservoirs because there has been little incentive to explore these types of reservoirs since they currently have little to no economic value. Disposal of liquid industrial and municipal wastes into saline reservoirs represents their single biggest use. Even in oil and gas provinces where wells are numerous, oil and gas operators will not typically characterize saline reservoirs because of the added cost of doing so. Therefore, data on saline reservoirs is typically lacking and may be limited to geologic descriptions from drilling logs.

Unlike depleted oil and gas reservoirs, which have undergone production and decline in reservoir pressure, saline reservoirs have relatively high starting pressures, which have the following implications:

- Injection pressures and rates may need to be lower to prevent over-pressuring the reservoir and fracturing the caprock, potentially requiring more wells and infrastructure costs;

- Saline water extraction and management may be required to lower pressures in the reservoir adding to the cost of storage, but perhaps providing an alternative source of water if treated;

What is the status of saline storage?

To date, there are only three large scale saline storage projects in the world that have (or are currently) injecting CO_2 at a rate approaching one million metric tons per year. It is important to note that each of these projects involves CO_2 separation from a natural gas stream and the annual amount stored per site is a third of the CO2 that would be stored by a single 1,000 MW coal-fired EGU as described at the beginning of this testimony. None of these projects involve the engineering, design and operational experience needed to optimally integrate an advanced coal-fired power unit with a full-scale capture, transport and storage facility to maximize system performance. However, from a geologic storage perspective, the following large-scale saline project experiences are relevant and very important for the following reasons:

- The Sleipner natural gas project operated by Statoil in the North Sea (Norway) is the flagship of the global CO_2 saline storage projects. Due to the immense size and high permeability of the sub-seabed storage reservoir at this location, the Sleipner project has been able to inject CO_2 at a sustained rate of 1 million metric tons for nearly twenty year (since 1996).
- The Snohvit natural gas project, another offshore CO_2 storage project operated by Statoil in the Barents Sea (Norway), started injecting CO_2 in 2008. However, the project immediately found that the permeability of the target formation was to low and pressures climbed rapidly, requiring mitigation. Fortunately, multiple stacked reservoirs[3] gave Statoil the flexibility to select another injection interval, allowing the project to continue injecting at a sustained rate of ~820,000 metric tons per year.
- The In Salah natural gas project, located in central Algeria, is an onshore project operated by British Petroleum. Approximately one million metric tons of CO_2 was injected per year into three horizontal wells starting in 2008. The project suspended injection in 2011 after monitoring data and supporting analyses indicated that the lower 650 ft of the 3,120 ft thick caprock above the storage reservoir had likely fractured due to CO_2 injection pressures.[4]

It is important to note that although the In Salah project is no longer injecting CO_2, the CCS community still views this early saline project as a success because the monitoring program served its intended purpose. That is, the monitoring methods deployed at the site informed the operator of a potential problem, leading to a shutdown of CO_2 injection before the caprock was breached.

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[3] Multiple layered reservoirs at the same location, which geologist referred to as stacked reservoirs or stacked storage, are ideal because it offers multiple injection layers and greater operational flexibility compared to a single layer.

[4] White, J. A., L. Chiaramonte, S. Ezzedine, W. Foxall, Y. Hao, W. McNab, and A. Ramirez, In Salah CO_2 Storage Project, Lawrence Livermore National Laboratory, Project Number: FWP-FEW0174 Task 2, presentation at theU.S. Department of Energy, National Energy Technology Laboratory, Carbon Storage R&D Project Review Meeting, August 20-22, 2013

Of noteworthy importance, is the Gorgon LNG Project off the northwest coast of Western Australia, which is scheduled to begin injecting CO_2 in 2015. The natural gas processing facility will inject 3.4 to 4 million metric tons of CO_2 per year into a saline formation. A total of 120 million metric tons of CO_2 will be injected over the project's 40 year lifetime, representing 40 percent of its emissions. CO_2 emissions produced by the Gorgon project is equivalent to the 1,000 MW EGU case described earlier.

CO_2 Storage Research

The Department of Energy (DOE) has played a pivotal research role in the US and abroad by designing and managing a CO_2 storage research program that is applied and focused on developing monitoring and analytical tools that industry can use to implement CCS projects. DOE's research approach includes regional mapping of saline, oil and gas and coal-seam reservoirs and a nation-wide assessment of their CO_2 storage capacity that industry can then use to identify and screen potential storage sites. DOE has and is currently fielding demonstration projects involving CO_2 injection ranging from a few hundred tons to 250,000 tons per year to develop the experience base and tools needed to successfully deploy CCS. Additional demonstration projects are planned that would involve injecting one million metric tons of CO_2 per year. The Regional Carbon Sequestration Partnership program, Industrial CCS program and Clean Coal Power Initiative are key DOE demonstration programs.

Given the fact that the NSPS is clearly focused on reducing emissions from fossil fuel-fired EGUs, continued DOE investment in future research involving capture and saline demonstration projects that are fully integrated with advanced power generating systems is needed and would be invaluable to the power industry. Only two of the demonstration projects in DOE's research portfolio fielded to date have involved slip stream capture of a relatively small amount of CO_2 from two power stations with corresponding injection into saline reservoirs of 37,000 and 100,000 metric tons. These include the injection projects performed at American Electric Power's Mountaineer power station in West Virginia and the Alabama Power Company's Plant Barry power plant in Alabama supported by EPRI. The FutureGen2 project located near Meredosia Illinois is a commercial scale oxy-combustion power system that will produce 1.1 million tons of CO_2 emissions each year. Currently in the planning stages, if the DOE-supported FutureGen2 project progresses, it will be the first full-scale EGU involving CO_2 saline injection in the United States.

Summary

The CCS community recognizes that we will likely turn to saline reservoirs for our large-scale, long-term CO_2 storage needs because of their wide spread distribution and large storage capacity. The potential use of depleted oil and gas reservoirs for CO_2 storage could be adversely affected by potential regulatory requirements associated with CO_2 storage and could have the unintended consequence of accelerating the move to saline storage. Given that more is known about oil and natural gas reservoirs because of their commercial value, future government storage research and funding may need to focus disproportionately on characterization of saline storage reservoirs to help close the knowledge gap. This would help facilitate deployment and hasten the transition to saline storage.

The Sleiper, Snohvit, and In Salah projects described earlier provide invaluable learning experiences. More importantly, these projects illustrate the risks associated with storage and geologic uncertainty associated with selecting a saline storage site. The projects also illustrate our need to rapidly expand our experience base to scales that are commensurate with full-scale commercial power projects. With experience comes greater technical certainty and operational reliability upon which sound financial investment decisions can be made. Further government investment in research is needed that will integrate fossil fuel-fired power projects with capture and saline storage at full scale to demonstrate that the technology is feasible and reliable. By doing so, it can reduce operational and financial uncertainty.

Thank you for the opportunity to testify before you today and I welcome your questions.

Robert C. Trautz

Mr. Trautz is a Senior Technical Leader with the Electric Power Research Institute (EPRI) in Palo Alto, California. He has 30 years of experience in research and applied geology and hydrology involving CO_2 storage, radioactive-waste disposal, and groundwater remediation. Mr. Trautz received a Bachelor of Science degree in Geology from Michigan State University in 1981 and a Master of Science in Hydrology from the University of Arizona in 1984.

Mr. Trautz is responsible for identifying key policy and technical issues related to geologic storage of CO_2, developing the EPRI geologic storage research program in consultation with EPRI utility members, establishing funding priorities and direction, and managing the research effort.

Mr. Trautz manages and serves as the technical leader for several CO_2 storage field demonstration projects funded by the U.S. Department of Energy (DOE), EPRI and/or industry. The overall goal of these field projects is to demonstrate safe, reliable geologic storage of CO_2. Specific demonstration project experience includes the:

- West Coast Regional Carbon Sequestration (WESTCARB) Arizona Utilities CO_2 Storage Project (2005–2010) designed to explore CO_2 storage opportunities in northern Arizona
- Southeast Regional Carbon Sequestration (SECARB) Mississippi Saline Test (2005–2009) – small scale, 3,000 ton injection of CO_2 into the Lower Tuscaloosa sandstone at Plant Daniel, Mississippi
- SECARB Anthropogenic Pilot Test (2008–2017) – the project has captured over 100,000 metric tons of CO_2 from Plant Barry and stored it in the Paluxy saline formation near Citronelle, Alabama
- AEP Mountaineer Project (2010–2012) – served as an EPRI advisor for the 37,000 CO_2 ton storage project at the Mountaineer Power Station, West Virgina
- Distributed Fiber Optic Monitoring Project (2013–2016) – Principal Investigator for this innovative project designed to use fiber optic sensor arrays for monitoring CO_2 storage sites

Prior to joining EPRI in late December 2007, he worked at Lawrence Berkeley National Laboratory (1997-2007), Environmental Science & Engineering (1990-1997) and the U. S. Geological Survey (1987-1990) in different capacities.

Chairman SCHWEIKERT. Our fourth witness today is Scott Miller, General Manager and CEO of City Utilities of Springfield, Missouri, a member of the American Public Power Association. Mr. Miller joined the City Utilities in 2002 as the Associate General Manager for Electrical Supply and was named General Manager and CEO in 2011. Mr. Miller also serves on the board of directors of the American Public Power Association and the Missouri Joint Municipal Electric Utility Commission. He has 27 years of experience in the utility industry.

Mr. Miller, five minutes.

TESTIMONY OF SCOTT MILLER, GENERAL MANAGER AND CEO, CITY UTILITIES OF SPRINGFIELD MISSOURI, AMERICAN PUBLIC POWER ASSOCIATION

Mr. MILLER. Thank you, Mr. Chair.

I have been in the industry 27 years. I represent City Utilities of Springfield. We are a municipal utility. We offer electric, natural gas, water, broadband and transit services to the Springfield area. We have over 1,100 megawatts of generation and we serve over 220,000 customers. I am also a member of the board of directors at APPA, and we represent the interests of over 2,000 community-owned utilities, not-for-profit utilities, that provide services to over 47 million Americans. We provide locally controlled, low-cost, reliable, efficient and environmentally responsible energy.

The public power utilities are concerned about the potential for likely impacts the EPA regulating greenhouse gas emissions from new power plants by establishing New Source Performance standards under the Clean Air Act. In particular, public power utilities strongly disagree with EPA's conclusion that carbon capture and storage is the best system of emission reduction, or BSER, for reducing CO_2 emissions. The conclusion is premature, given that there are no commercially operating coal plants using this technology, and the agency's failure to address the variety of regulatory hurdles that are impeding sequestration and CO_2 in the United States.

City Utilities was recently involved with a carbon sequestration project within our state. Our experience highlights some of the issues that would be addressed before CCS could be deemed as adequately demonstrated. In 2005, we got together with the generating utilities across the state to determine what were we going to do if carbon emissions were regulated. At the time, over 70 percent of our generation came from coal-fired generation. Much of the research that we had seen did not address shallow sequestration issues that we would have had for geologic formations within our state. In 2008, City Utilities received $4.7 million of federal funding administered through DOE so that we could do the Missouri Shallow Carbon Sequestration Project. City Utilities with Kansas City Power and Light, the Empire District Electric, Ameren Missouri, and Associated Electric Cooperative also matched funds of $1.2 million, so we had our customers' money involved with the project. The project's purpose was to evaluate the feasibility of on-site sequestration at the power plants. The project targeted sandstone formations that were approximately 2,000 to 3,500 feet, which mean that we would be injecting in a gas phase as opposed to the liquid or supercritical phase. The original plan targeted saline aquifers, which we just heard about, and small injections of food-grade CO_2 to see how that would be encapsulated within the formation. Our research was conducted by Missouri State University, Missouri University of Science and Technology, and our DNR within the state.

The John Twitty Energy Center at City Utilities was the primary site. The drilling was conducted and we reached the Precambrian level at about 2,200 feet, but we were not allowed to inject because what we found was the water quality in that area was potable. We were expecting saline and it was potable water. So federal regulations stopped us from injecting at that point. We had to change our project, and we decided to go to other sites within the state in the northwest, north central and near the St. Louis area so that we could determine if they were actually saline aquifers in a shallow formation within our state.

In summary, we spent about $5.8 million for the testing. We found one area of the state that has now been eliminated because of the quality of the water. We have two others that we have identified in the state that we believe are acceptable, and we were also able to identify three areas where the confining layer looked to be a positive where it would confine the CO_2 within the aquifer. However, we were not allowed or were not able to complete our pressure testing or aquifer permeability because of cost limitations, so we were not able to substantiate through CO_2 injections that we had the ability for long-term storage within our state.

Based upon the results of this project and others that we have seen across the United States and across the world, CCS technology is not really a realistic option for utilities seeking to reduce their CO_2 emissions in the near future. As a CEO of a municipal utility, one of my responsibilities is to our city and our customers, that if we are going to spend their money, we need to know that it is going to go towards something that will function for them, and we do not have a high degree of confidence that CCS will do that for us.

In looking at all the CCS research that is out there, it appears there is no factual basis that EPA may assert that carbon sequestration technology has met the Clean Air Act's three-part test, which is the technology needs to be adequately demonstrated, it needs to be widely available and it needs to be shown to be technically and economically feasible, and we don't believe that that is out there.

Thank you.

[The prepared statement of Mr. Miller follows:]

Hearing of the House Subcommittee on Environment and Subcommittee on Energy of the Committee on Science, Space, and Technology

Written Statement of Scott Miller
General Manager of City Utilities of Springfield
On Behalf of the American Public Power Association
March 12, 2014

Dear Chairmen Schweikert and Lummis and Ranking Members Bonamici and Swalwell, thank you for the opportunity to speak at today's hearing to explore the technological requirements for meeting the newly proposed New Source Performance Standards (NSPS) for emissions of carbon dioxide (CO_2) for electric generating units (EGUs). My name is Scott Miller and I am the General Manager and Chief Executive Officer of City Utilities of Springfield (City Utilities). I am also a member of the Board of Directors of the American Public Power Association (APPA). I am testifying on behalf of my utility and APPA.

City Utilities is a municipal utility that provides electric, natural gas, water, broadband, and transit services to the Springfield area. We serve a population of over 222,000 and have generation capability over 1,100 MW, which includes a mix of fossil and renewable sources. In addition, CU is developing Missouri's largest solar farm.

City Utilities is a member of APPA, the national service organization representing the interests of over 2,000 community-owned, not-for-profit electric utilities. These utilities include state public power agencies, municipal electric utilities, and special utility districts that provide electricity and other services to over 47 million Americans, serving some of the nation's largest cities. However, the vast majority of APPA's members serve communities with populations of 10,000 people or less.

Overall, public power utilities' primary purpose is to provide reliable, efficient service to local customers at the lowest possible cost, consistent with good environmental stewardship. Public power utilities are locally created governmental institutions that address a basic community need: they operate on a not-for-profit basis to provide an essential public service, reliably and efficiently, at a reasonable price.

APPA commends you for holding a hearing exploring the technological requirements for CCS for new fossil fuel-fired power plants. Public power utilities are concerned about the potential or likely impacts of the Environmental Protection Agency (EPA) regulating CO_2 emissions from new power plants by establishing NSPS under the Clean Air Act. The agency's September 20, 2013, re-proposed rule concludes that CCS is the best system of emissions reduction (BSER) adequately demonstrated to reduce CO_2 emissions.[1] APPA strongly disagrees

[1] For the re-proposed NSPS, EPA applied a four-part test to determine BSER. First, is the system of emissions reduction technically feasible? Second, are the costs of the system reasonable? Third, what amount of emissions reductions will the system generate? Fourth, does the system promote the implementation and further development of technology? See p. 25 of Proposed Rule: Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (Jan. 8, 2014), Docket - EPA-HQ-OAR-2013-0495.

with EPA's conclusions about the commercial demonstration of the technology and believes the agency has failed to look at a variety of issues related to the long-term sequestration of CO_2. Until these issues are addressed, it is premature to require the use of CCS by new coal-fired power plants.

I. EPA's Conclusion That CCS Is Adequately Demonstrated Is Premature.

The re-proposed NSPS would require new coal-fired power plants to achieve an emissions limit of 1,100 pounds of CO_2 per megawatt/hour (lbs CO_2/MWh) (gross) based on a 12-month rolling average compliance period. In the alternative, coal-fired power plants could achieve an emissions limit between 1,000-1050 lbs CO_2/MWh (gross) based on an 84-month rolling average compliance period. Use of CCS technology would be required to meet either standard. Natural gas units with a heat rate greater than 850 MMBtu/h would be subject an emissions limit of 1,000 lbs CO_2/MWh (gross) and need no additional control technology to reduce emissions.

In justifying the use of CCS, EPA modified its definition of the BSER in a manner that promotes newly emerging technologies, such as CCS. The agency asserts that BSER can be technology forcing and consider "the impact a standard will have on further technology development." While the re-proposal acknowledges that there are no commercially operating coal-fired power plants using CCS, the re-proposal asserts that four demonstration projects under development in the U.S. and Canada adequately demonstrate CCS at commercial scale. EPA never addresses the fact that there is no commercial demonstration of sequestration in non-oil and gas recovery locations. Nor does the agency address the myriad of regulatory hurdles impeding the sequestration of CO_2 in the U.S.

A. EPA's Assertion That It Only Needs to Find Carbon Capture, but Not Sequestration Adequately Demonstrated and Achievable Is Erroneous.

EPA looked at three technologies to reduce CO_2 emissions from fossil fuel-fired power plants: (1) super critical pulverized coal (SCPC); (2) total CCS (defined as capturing more than 90 percent of emissions); (3) "practical" CCS (not defined, but implicitly less than 90 percent capture). Comparing the emissions reductions from the three technologies, the agency concluded that partial CCS was BSER because the emissions reductions "that would result from an emissions standard based on SCPC or Ultra Super Critical Pulverized Coal (USCPC), or even IGCC, "would not be consistent with the purpose of CAA Section 111 to achieve 'as much [emission reduction] as practicable.'"[2]

Notably, the proposed NSPS is called partial CCS, but the standard itself is defined solely for purposes of compliance as carbon capture. Nonetheless, throughout the NSPS proposal, there are disjointed discussions of the availability and achievability of both carbon capture and sequestration. Recently, agency officials have emphasized, however, that the agency need only demonstrate the adequacy and achievability of carbon capture. For example, during EPA's Science Advisory Board (SAB) review of the proposed standard in December 2013 and January 2014, the Administrator and other EPA officials underscored that since compliance with the proposed NSPS was limited to carbon capture, the SAB's review of the proposed BSER was

[2] *Id.*

likewise limited to the scientific and peer review issues regarding "carbon capture" (1,100 lb. CO_2/MWh), not sequestration of the CO_2 captured. These assertions, which are repeated in various places in the Notice of Proposed Rulemaking (NPRM),[3] appear to be intended to justify the technical and legal basis for claiming that carbon sequestration has been adequately demonstrated and achievable.

B. None of the Projects or Historical Enhanced Oil Recovery (EOR) Experience EPA Relies Upon Provide a Sufficient Basis to Conclude CCS Is BSER.

EPA asserts that partial CCS is "adequately demonstrated" based on the operation, construction, and/or development of pilot CCS projects at four base load and intermediate load fossil fired EGUs. The pilot projects are Southern Company's Mississippi Kemper Station, SaskPower's Boundary Dam operation, the Texas Clean Energy Project, and the Hydrogen Energy California project. In addition, EPA relies on historic enhanced oil recovery (EOR) operations and terminated international CCS projects as proof that CO_2 sequestration is adequately demonstrated. These characterizations are simply misleading because CCS is not operational, development of the projects is reliant on huge government subsidies, and at least one has been suspended for various technical and financial reasons.

While CO_2 has been recycled in the oil and gas sector for almost forty years, the idea of permanently sequestering it is novel. CO_2 gas functions like a solvent to move oil and gas more effectively than water flooding. The CO_2 currently used in the oil and gas sector in the U.S., Norway, Australia, and Canada is recycled, not permanently stored. Recycling of the gas is far different than permanently storing it underground for thousands of years. The oil and gas sector typically stores the gas for days, weeks, and sometimes months, and usually removes and transports it by specialty pipeline for use at the next oil and gas recovery location.

C. To Date, No CO_2 Has Been Injected and Sequestered at Any of the Cited Demonstration Projects.

None of the four pilot projects described in the NPRM actively capture CO_2 from plant exhausts or sequester CO_2 in the ground. Of the four, two are in the process of being constructed and two are in development. Of the two being constructed, the Kemper plant faces development costs in excess of $1 billion,[4] and is dependent on a technology development for a lignite coal that is not available any other place in the country. The second plant under construction, in Canada, is a post combustion CCS operation at a small research facility boiler that is not scalable.

Of the two projects still in development, there is no firm timeline for construction of either. The California polygeneration project is not expected to get its construction permit for another nine months and then the construction itself will take almost four years. Thus, CO_2 will not be injected in the California project for at least four years, at the earliest. The Texas project, which is not operational, has been unable to secure a purchase power contract from an electric utility and thus the project has been suspended.

[3] *Id.* at 1483/column 3.
[4] Southern Co.: Kemper Plant Construction Cost Could Grow by $40M, Mississippi Business Journal, January 29, 2014, available at http://msbusiness.com/blog/2014/01/29/southern-co-kemper-plant-construction-cost-grow-40m/.

Since CCS is not operational at these pilots, there is no data about their continuous operations, whether the technology can be scaled to commercial operations, or the cost of that technology. Therefore, these pilots cannot form the basis for a finding that the technology is available. EPA is violating the law by making assumptions about a future, theoretically possible technology.

There also is no mention in the NPRM of the inability to complete three CCS pilot projects by public power utilities in Jamestown, New York, Holland, Michigan, and southern Missouri that were discontinued when captured carbon was not feasible for a variety of reasons. City Utilities was actively involved in the Missouri Carbon Sequestration Project. Our experience highlights just some of the issues that need to be addressed before CCS technology can be declared adequately demonstrated.

II. CU's Experience with the Missouri Carbon Sequestration Project.

In 2005, a group of Missouri generating utilities gathered to discuss how CO_2 emissions could be managed if future regulations were imposed. At the time, over 70 percent of electricity provided in the state came from coal-fired generation. It was also becoming apparent that much of the carbon storage research was not addressing geologic conditions found in Missouri. To address this gap in research, City Utilities, Kansas City Power & Light, The Empire District Electric Company, Ameren Missouri, and Associated Electric Cooperative entered into a cooperative agreement with the Department of Energy's National Energy Technology Laboratory (NETL) to research the sequestration of CO_2 in several formations in Missouri.

The project, entitled the Missouri Shallow Carbon Sequestration Demonstration Project, was funded by Congress in two appropriations in fiscal years 2008 and 2010 totaling $4.7 million. Missouri's generating utilities provided a matching share of approximately $1.2 million. CU recently concluded its research activities related to the project.

The purpose of the project was to evaluate the feasibility of on-site carbon sequestration at power plants in Missouri. The project is called shallow carbon sequestration because the target sandstone formation was believed to be at approximately 2,000 to 3,500 feet below the surface. Most sequestration research is directed toward geologic basins at a depth on the order of 10,000 feet. At the shallower depth, CO_2 injection and storage would be in the gas phase, as opposed to liquid, also referred to as supercritical phase, which occurs at greater depths.

The original plan was to drill injection and monitoring wells and inject small quantities of food grade CO_2 to test the ability of the target formation to receive that CO_2. A later monitoring phase was planned to determine the ability of the formation to hold the CO_2 in place for a period of ten or more years. The research was conducted by project partners Missouri State University, Missouri University of Science and Technology, and the Missouri Department of Natural Resources. The project included laboratory analysis of core and water samples, development of hydrogeologic models, bench scale testing of permeability, porosity, and chemical interactions, and downhole testing of geophysical properties.

Some of the project's original objectives were achieved, but ultimately we were not able to substantiate our ability to sequester CO_2 within the state. The site identified for exploration was at City Utilities John Twitty Energy Center, the location of our two largest coal-fired power units with a combined capacity of approximately 500 MW. Drilling and coring proceeded to a depth of 2,186 feet to the Precambrian basement rock. However, the planned injection of CO_2 was not possible. Water quality analysis in the target formation found the Total Dissolved Solids well below the Safe Drinking Water Act standard of 10,000 mg/L, thus precluding injection under federal regulations.

Laboratory testing of core samples did allow an estimate of carbon sequestration potential. Based on a presumed 800 m x 800 m reservoir, a total CO_2 storage capacity of 2.55×10^5 metric tons over 15.8 years was calculated. This would represent about 1 percent of the CO_2 production at John Twitty Energy Center during normal operations during that time frame. In other words, should sequestration have been possible, it would require over 100 wells or well fields, at a conservative cost estimate of $1 million per well, to attain this level of storage capacity, if actual injection corresponded to laboratory test results.

The project was then modified to redirect funds to perform drilling and testing, to the degree funds would allow, at the other partner locations around the state. A second borehole was located at Associated Electric's Thomas Hill Energy Center in North Central Missouri. Basement was encountered at 2,540 feet. Water quality at the target formation was sufficiently saline to permit injection. As at Springfield, the confining layer was found to be effective. Laboratory testing demonstrated reservoir capacity approximately five times greater than Springfield.

The third site was located at Kansas City Power & Light's Iatan Generating Station. Drilling was completed to a depth of 2,090 feet, but due to time and material limitations, the basement rock level was not achieved, nor was core collected.

The fourth site was near an Ameren Missouri plant location south and west of St. Louis. Depth of the target formation was significantly greater than anticipated. Drilling was terminated at 3,625 feet due to physical limitations of the drilling equipment, before reaching Precambrian basement rock. Again, the confining layer and water quality were found to be acceptable for injection. Additionally, the depth of the target formation suggested that super-critical injection might be possible. Gas phase storage was calculated at approximately twice that of Springfield.

In summary, approximately $5.8 million of testing revealed one site where water quality would not permit injection, and we identified two other sites where further testing might be considered. The confining layer analysis was one of the major successes of the project. The project partners were able to identify that the confining layer in three of the locations appear to be adequate to contain CO_2 on the aquifer. Originally planned pressure testing and aquifer permeability had to be abandoned due to cost limitations, so no CO_2 test injections were performed. While some target formation storage capacity was calculated based on laboratory testing, we were not able to demonstrate the long-term storage capability.

Based on the results of the project, it is not clear to City Utilities that CCS technology is a realistic option for utilities seeking to reduce their CO2 emissions from fossil fuel-fired power plants in the near term. As the CEO of a municipal utility, I have an obligation to the city and our customers to spend their money wisely. I cannot tell customers that I would have a degree of confidence that CCS would work.

Looking at all CCS research conducted to date, there appears to be no factual basis on which EPA may assert that carbon sequestration technology has met the Clean Air Act's three-part test for BSER. Sequestration technology has been not adequately demonstrated. It is not widely available and has not been shown to be technically and economically feasible.

III. EPA Failed to Assess the Non-Air Public Health Environmental Impacts in Determining that Partial CCS Is BSER.

Clean Air Act Section 111(a) requires EPA to select a standard of performance that:

> [R]eflects 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.

EPA's preferred NSPS option for coal-fired EGUs—partial CCS—fails to assess or discuss the "non-air public health and environmental impacts" of the technology. The proposed regulation does so by defining CCS as "carbon capture" (i.e., the "s" is silent). Agency protestations that the "non-air environmental effects" of sequestration either do not need to be examined or were examined in a recently issued Class 6 Underground Injection Control (UIC) permit rulemaking[5] are unavailing. The failure to examine non-air environmental consequences of CCS is a blatant violation of the letter and the spirit of the Clean Air Act and the public's trust. EPA's proposed NSPS for fossil fuel-fired EGUs could create an imminent harm of transferring air pollution to other environmental media, not dissimilar to man's disposal of wastes in much of the 19th and 20th Centuries without consideration of the potentially profound human health and environmental damages that would result.

Below are some of the issues the agency failed to address in its BSER determination. These include issues outside the scope of the Clean Air Act.

Hazardous Substance and Superfund Implications for Environmental Releases. EPA has not affirmed whether injection and sequestration of CO_2, an acid gas, is safe in non-oil and non-gas recovery locations. The agency needs to consider whether an acid gas would have the potential to change the pH of soil or, if released into the environment, whether it poses a potential threat to health or the environment. If acid gas injections have the potential to trigger remediation under the Community Emergency Response, Compensation, and Liability Act (CERCLA) (also known as the Superfund Act), then clearly the technology cannot be demonstrated.

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[5] 79 Fed. Reg. 350 (Jan. 3, 2014).

Surface Water Contamination. There are increasingly significant questions regarding surface water quantity and quality raised by partial CCS. These involve the substantial quantities of water used in the injection process and the effect of large amounts of compressed gases on groundwater and surface water movement. Also, it is well understood within the agency's water office that seasonal surface water flow is very much affected by hydraulic heads in various groundwater aquifers. Altering these pressure gradients can cause numerous human health and environmental impacts, none of which have been studied by EPA in the context of permanently disposing vast quantities of compressed gases. They are, however, dramatically demonstrated by unprecedented water shortages currently being experienced in western and plains states. APPA believes that these "quantity" issues, ironically, could be exacerbated by the proposed BSER solution, particularly in western states experiencing drought conditions.

Moreover, there is tremendous potential for CCS to interfere with access to water in western states. For example, EPA has not taken into consideration the fact that subsurface western water rights are often depth restricted. Other physical consequences for drinking water, such as changes in hydraulic heads pushing water toward or away from groundwater wells and surface waters, must be closely analyzed and peer-reviewed.

Navigable Waters and Surface Water Flow. Given that EPA is considering policies affecting waters of the United States in another proceeding, it should also examine the consequences of subsurface CO_2 sequestration on "navigable waters" that support a variety of commercial and ecological interests. The agency needs to examine whether there is any chance that subsurface locations where CO_2 is sequestered could later be declared navigable waters.

Endangered Species Act (ESA): There is nothing in the record indicating that EPA has consulted with the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to determine whether sequestration of CO_2 into deep saline aquifers is permitted. Many deep saline aquifers run either through or under ESA's Habitat Conservation Plans, Conservation Banks, and Safe Harbor Agreement sites. While EPA may not be *required* by the CAA to consult with FWS in this specific rulemaking, permit applicants for federal CAA construction permits have to do so.

As U.S. Court of Appeals for the D.C. Circuit Judge Leventhal reminded EPA in *Portland Cement v. Ruckelshaus*[6] – shouldn't the agency be held similarly accountable? If not, how might these ESA-protected areas limit locations for sequestration? Has EPA or NETL attempted to reflect these limitations in its assessment or NETL's Carbon Sequestration Atlas,[7] which gives its prediction of potential geologic sequestration sites? The DOE Carbon Sequestration Atlas does not indicate areas with other environmental restrictions, such as National Parks, Wilderness Areas, etc., where sequestration of CO_2 might not be allowed. Very little mapping has been done of deep saline aquifers on the granular level required to actually predict CO_2 storage on a gigaton basis.

Land Planning: Little, if any, consideration has been given to the amount of land that is required for a commercial-sized operational partial CCS system. Such operations require at least

[6] 486 F.2d 375

[7] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/

six square acres of surface space, almost inconceivable for most plants owned by public power utilities and many plants owned by investor owned utilities that were constructed between 1950-1970 near population centers and close to rivers and other water ways for cooling water and coal delivery.

Seismic Activity. Although EPA maintains that it has consulted the U.S. Geological Service (USGS) about seismic activity in the vicinity of EOR, agency officials have not sufficiently consulted with USGS regarding injection of CO_2 in non-oil and gas formations. Nor has the agency addressed specific concerns researchers have that are related to how quickly the CO_2 may be injected to maintain pressure in the rock. In addition, there is nothing in the record that shows that has EPA consulted with state departments of geology about their concerns with the vulnerabilities posed by injection of huge volumes of CO_2 under pressure, including potential earthquakes from hydraulic fracturing (HF). The agency is looking at these issues in its recent inquiry into seismic events for water injects in Oklahoma and Texas for natural gas production disposal wells. Why does it not also inquire and answer these questions in the context of geologic sequestration of CO_2?

In addition, EPA apparently assumes injection research efforts would be free based upon its assessment that the NSPS would have no research and development costs associated with each sequestration project. There are no projections on the cost of detailed acoustic and seismic readings in geologic locations where there is no extractive industry. The agency also appears to assume that there is no cost involved with the multimillion dollar subsurface studies needed in order to conduct permit applications under UIC Class V, Class VI, or Class II for injection of CO_2 by power plants. It is highly improbable that this data exists in the public domain or that it would be free. EPA needs to account for these costs and factor them into its analysis of CCS.

While the separation of CO_2 might be demonstrated, the sequestration of CO_2 is inherently location specific. This means that in each underground location, detailed acoustic readings and seismic assessments must take place by bonded, licensed, and experienced companies to determine the carrying capacity and injection rate into that rock formation for 30 to 50 years. These companies must also rule out any risks of inadvertent seismic events. The NETL Carbon Sequestration Atlas is informative, but offers no indicators of the carrying capacity or storage retention capacity of the listed geologic formations. That information is rock and location specific.

Natural Resource Depletion. EPA's proposed rule fails to identify the consequence of CCS on fossil fuel resources. What makes this glaring omission so troubling is that the record indicates that the agency consulted with the Department of Energy (DOE) and Energy Information Agency (EIA). Yet EPA and DOE apparently missed the very important concept that because CCS separation and injection technologies actually use more fuel with a parasitic power loss of about 30 percent at the plant, that coal-fired power plants (and natural gas-fired power plants with CCS, should that one day be required) will actually cause a hastening of the use of U.S. coal and natural gas. The depletion of fuel resources is equally a requirement of NEPA-like assessments.

Resolution of Underground Access and Trespass Issue. A question EPA has failed to address is how can a technology be demonstrated if it is not legal in all 50 states for a party to inject into and under the property owned by others? Many states do not have separate surface and subsurface land ownership. In most states, a property owner owns what is his land from the surface to "the heavens" and to the middle core of the earth. Only in extractive industry states are there separate ownership options to enable oil, gas, and hard/soft rock mining. Where there are no options for "mineral rights" ownership, the geologic sequestration of CO_2 that might migrate under another person's property is a legal trespass. This is a critical legal issue that has to be resolved before declaring that CCS is commercially demonstrated. Interestingly, all three of the U.S. CCS pilot projects are in oil and gas recovery operations and those states have mineral right ownership of the subsurface.

APPA has several papers and presentations that elaborate in more detail on the issues with CCS. A list of the documents and the links where they can be accessed is included at the end of this statement.

IV. EPA's Science Advisory Board (SAB) Questioned Whether the Agency Addressed Cross-Media Issues in Peer Review Regarding Geologic Sequestration.

On December 4 and 5, 2013, EPA's SAB raised concerns about the scientific and technological bases EPA relied upon when proposing to mandate CCS for NSPS for new coal-fired power plants. Specifically, the SAB expressed concern with the peer review process of the DOE studies that were relied upon in the proposed rule, how the agency came up with its emissions limits for new coal- and natural gas-fired power plants, and the fact that the proposed rule does not address the sequestration side of CCS. EPA responded to those concerns by asserting that regulatory mechanisms for addressing sequestration were outside the scope of Clean Air Act and thus do not need to be addressed in the NSPS for new fossil fuel-fired power plants. Agency staff stated that only the capture side of CCS needs to be addressed.

The SAB, in a letter to EPA Administrator Gina McCarthy, dated January 29, 2014, stated it "defers to EPA's legal view...that the portion of the rulemaking addressing coal-fired power plants focuses on carbon capture" because that is all that is within the scope of the Act. The letter notes, however, that "carbon capture is a complex process, particularly at the scale required under this rulemaking, which may have multi-media consequences." The board expressed its strong view that "a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in important systematic ways to this rulemaking." It encouraged EPA to have the National Research Council review the research and information on sequestration conducted by it, DOE, and other sources.

While SAB deferred to EPA's legal interpretation of its authority to look at cross-media issues rising from sequestration of CO_2, it is significant that the SAB raised these concerns. It is clear that several members of the SAB agree with APPA that these issues need to be resolved before CCS is declared BSER.[8]

V. Conclusion

APPA believes it is premature to conclude that CCS is the BSER adequately demonstrated. While CCS may one day be a viable, economic, and commercially demonstrated technology utilities can use to reduce CO_2 emissions from power plants, it is not one they can use today or in the near future. There are a host of issues EPA has failed to look at related to the long-term sequestration of CO_2, including "non-air public health and environmental impacts" of CCS technology. The agency essentially equates sequestration with EOR. They are not the same. EOR is only available in parts of the country with oil and gas reserves and involves the recycling of CO_2 with no long-term storage. CO_2 captured from power plants in non-EOR areas will need to be stored for thousands of years. The results from the Missouri Shallow Carbon Sequestration Project show that further research is required before utilities can sequester CO_2 in the ground. And based on all CCS research conducted to date, there appears to be no factual basis on which EPA may assert that carbon sequestration technology has met the Clean Air Act's three criteria. Sequestration technology has been not adequately demonstrated. It is not widely available. Nor has it been shown to be technically and economically feasible. Until it has, EPA should reverse its determination that CCS is BSER.

[8] Per the request of the SAB, APPA sent a letter to it on December 9, 2014, outlining our concerns with the many obstacles to commercial demonstration of sequestration. The letter can be viewed at http://www.publicpower.org/files/PDFs/APPA%20Letter%20to%20EPA%20on%20SAB%20--%20FINAL%20--%2012-9-2013.pdf.

Carbon Capture and Storage Papers & Presentations Commissioned by APPA

L.D. Carter, White Paper, "Retrofitting Carbon Capture Systems on Existing Coal-fired Power Plants," November 2007 http://www.publicpower.org/files/PDFs/DougCarterpapernov07.pdf

L.D. Carter, White Paper, "Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA)," May 2007 http://www.publicpower.org/files/PDFs/Doug%20Carter%20-%20Carbon%20Capture%20and%20Storage%20From%20Coal.pdf

Doug Carter, Presentation, "Parasitic Power for Carbon Capture" http://www.publicpower.org/files/PDFs/CarterParasiticower.pdf

Timothy Gablehouse, White Paper, "Geologic CO_2 Issue Spotting and Analysis" July 2009 http://www.publicpower.org/files/PDFs/GablehouseSequestrationWhitePaper72209.pdf

Marianne Horinko, White Paper, "Carbon Capture and Sequestration Legal and Environmental Challenges Ahead," August 2007 http://www.publicpower.org/files/PDFs/Horinko%20CCS%20White%20Paper%20August%2007.pdf

Jonathan Gledhill, Policy Navigation Group; James Rollins, Policy Navigation Group; Theresa Pugh, APPA, White Paper, "Will Water Issues/Regulatory Capacity Allow or Prevent Geologic Sequestration for New Power Plants? A Review of the Underground Injection Control Program and Carbon Capture and Storage," November 2007 http://www.publicpower.org/files/PDFs/UICCCSpaper.pdf

Theresa Pugh Presentation, "Sober Thoughts About CCS for Retrofit or New Fossil Plants as a CO_2 Mitigation Measure from 2009-2029," Presented Nov. 3, 2009 http://www.publicpower.org/files/PDFs/PughCCSpresentation110309.pdf

Theresa Pugh Presentation, "Infrastructure Costs, Permitting Issues and Parasitic Energy Loss for Power Plants with CCS," Presented Jan 29, 2008 in Tucson, AZ http://www.publicpower.org/files/PowerPoint/TPEUECPresentation2008.ppt

Carbon Capture and Storage: Analysis of Potential Liabilities Associated with Groundwater Contamination Due to Geological Sequestration Operations, September 10, 2008
Prepared by Fredric P. Andes and Kari A. Evans, members of the Barnes & Thornburg LLP Water Team, for the American Public Power Association (APPA)
http://www.publicpower.org/files/PDFs/APPA%20CCS%20white%20paper%20Waters%20of%20the%20US.pdf

CITY UTILITIES

Bringing Power Home.

Scott Miller

Scott Miller is General Manager and Chief Executive Officer for City Utilities of Springfield, Missouri. He assumed his current responsibilities in June 2011. Scott joined City Utilities in 2002 as the Associate General Manager for Electric Supply. Prior to his career at City Utilities, Scott served as Director of Steam Generation for The Dayton Power and Light Company in Dayton, Ohio.

Scott earned a Bachelor of Science degree in Mechanical Engineering from the University of Texas at Austin, a Master's degree in Business Administration from Wright State University, and holds a Professional Engineers License. He has 27 years of experience in the utility industry.

Scott serves on the Boards of Directors of the American Public Power Association in Washington, DC, The Energy Authority in Jacksonville, Florida, and the Missouri Joint Municipal Electric Utility Commission. He is also active in a number of community organizations, including Springfield Business Development Corporation, Springfield Innovation, Inc., and the Partnership for Sustainability.

City Utilities of Springfield, MO provides electricity, natural gas, water, transit, and telecommunications/broadband services to 250,000 citizens in the city and surrounding area.

Chairman SCHWEIKERT. Thank you, Mr. Miller.

As all of you know, your written testimonies are being made now part of the record. I am going to turn to Chairwoman Lummis for the first five minutes of questions.

Mrs. LUMMIS. Thank you, Mr. Chairman.

First, I would like to ask all of our panelists for a show of hands, how many of you live on $1,226 a month right now? The record reflects that none of you raised your hands.

Let me tell you about this woman who was written about in the day before yesterday's New York Times, and Mr. Chairman, I would like to without objection submit the New York Times article "Coal to the Rescue but Maybe Not Next Winter" to the record.

Chairman SCHWEIKERT. Any objections on either of those? None heard.

Mrs. LUMMIS. Thank you.

[The information appears in Appendix II]

Mrs. LUMMIS. Well, let me tell you about this article. This woman had on her $1,200-a-month income her utility bills go up $100 just in one month. This article by Matthew L. Wald states that "At the end of the harshest winter in recent memory, the bill is coming due for millions of consumers who are not only using more electricity and natural gas but also paying more for whatever they use, and there might not be relief in future winters as the coal-fired power plants that utilities have relied on to meet the surge in demand are shuttered for environmental reasons."

Question, Mr. Miller. If the Nation's existing coal capacity cannot be replaced due to EPA's proposed New Source Performance Standards rule, where will you turn for new generation?

Mr. MILLER. We don't have a lot of options. I mean, coal is a foundation within our state. We would have to look to natural gas and we would have to look to purchases on the market, which would rely on mostly natural gas generation that would be coming online. The issue that we saw this winter is that we don't have the infrastructure for the natural gas for power generation at the same time that we are trying to make sure that people's homes stay warm. So when you have those in competition recently during the cold spell, we had to curtail our natural gas generation so that we had enough gas for people to heat their homes. So obviously it has a huge impact, and we have seen that push the price of natural gas up. So in general, I am not sure we have the natural gas infrastructure to support the transition from coal to other generation that is out there, and we have the same issue that you have—that was in that article. We have 22 percent of our customers that are living at the poverty level, so any time that you have additional costs implied through regulations, it goes right to their bottom line, and they are trying to figure out how to pay their bills.

Mrs. LUMMIS. Thank you.

Mr. Trautz, your testimony states that the new subpart RR requirements in the proposed rule could be a risk that EOR companies are not willing to accept. Where does this leave a power provider looking to invest in coal or natural gas if the EPA decides to require CCS for gas?

Mr. TRAUTZ. So for—the only thing that they would probably turn to is to saline reservoirs because those are broadly distributed and probably much closer to where the power plant is located, so they would turn to those reservoirs, which I indicated in my testimony, we know—we don't know as much about those reservoirs as we do the EOR fields.

Mrs. LUMMIS. So there is no good demonstration of the efficacy of saline reservoirs for storage?

Mr. TRAUTZ. Well, we have the Sleipner Project, which I mentioned in my testimony, that's on a natural gas separation but we currently do not have a full-scale project that is planned for saline storage. That would be an integrated project with a power plant.

Mrs. LUMMIS. Mr. Hilton, can you expand on your statement that NSPS hurt the development of CCS?

Mr. HILTON. It is fairly simple. I mean, all of R&D is driven by what the market demands, and if there is no demand for CCS on gas and there is only on coal and coal is not built as a result of that, it becomes a decision, does industry continue to invest because we are already seeing frankly that DOE has run out of money to invest in it. They don't have any large funds available. So it is up to the individual companies whether they want to continue to invest, and 10 or more years of waiting for a market is a long time.

Mrs. LUMMIS. Can you also discuss the importance of commercial guarantees and the commercial deployment of CCS?

Mr. HILTON. Yeah, everything we do—our industry has been incredibly successful and has lulled us all into the fact that there is all the power in the world that we ever want, and so as suppliers to that industry, we are expected to meet not just performance, and there are multiple performance guarantees on energy, on additives, on—there is also availability and liability guarantees with this equipment, and those come into potentially billions of dollars of liability. And that is why we need to have this demonstrated, to know that the integration works because there is no one that is going to accept that billions of dollars of liability otherwise.

Mrs. LUMMIS. Thank you, gentlemen.

I yield back, Mr. Chairman.

Chairman SCHWEIKERT. Thank you, Cynthia—Chairwoman Lummis.

Ranking Member Bonamici.

Ms. BONAMICI. Thank you, Mr. Chairman.

Mr. Hawkins, thank you for bringing your years of expertise to the Committee. On your testimony, you talk about how regulation has led to the development of technology. I think we are talking about a chicken-and-egg thing here. You note that CCS systems like sulfur scrubbers, mercury controls, fine particulate controls, nitrogen oxide controls, for example, were not used until they were regulatory requirements to control those pollutants. So I want to talk just a little bit about how the legislative history of the Clean Air Act supports the EPA's proposed rule on new power plants, and it is my understanding that the Senate committee that crafted Section 111 stated that the section was designed to promote constant improvement in techniques for preventing and controlling emission from stationary sources and an emerging technology used as the basis for standards of performance need not be in actual routine use somewhere. So can you please discuss how EPA regulation has in the past led to the development of critical environmental technology?

Mr. HAWKINS. Yes, ma'am. The regulation as a driver of technology is well documented both in academic literature—I am thinking of reports by Ed Rubin of Carnegie Mellon University. The fact is that in the power sector in particular, it is a very competitive sector in terms of the hours of operation of individual power plants. So a power plant that has a fractionally higher cost of electricity production is not going to run as much, and that is going to lose money or not earn as much money for the owner of that power plant. So power plant operators are extremely reluctant to do anything that has the slightly increase, even if it would be invisible in the customer's bill because it determines the hours of operation and what is called the dispatch order of that power plant.

So regulation or money are the essential ingredients to make advances, and if you don't have money, then you need standards, and that is why the Nixon Administration proposed what became the New Source Performance Standard in the 1970 Clean Air Act to advance technology deployment in new sources of air pollution, and the power sector is an excellent example of how that has worked very well. The coal industry and the power industry tout in ads how much of a reduction in the conventional pollution has been achieved at the power sector, and they are correct. What they don't say is it all came about because of regulation. It came out because of regulation requiring scrubbers, it came about because of regulation requiring bag houses for particulate matter, it came about for regulation requiring nitrogen oxide controls, and most recently, mercury and other toxin controls, and the same process will happen as we turn to carbon dioxide. Carbon dioxide is just another chemical. There are industrial processes for separating it just as there have been for conventional pollutants, and the sooner we get on with it, the better off we will all be.

Ms. BONAMICI. Thank you. And I wanted to ask you also, Mr. Hawkins, to follow up on the discussion that we have been having about the research that has been done to be able to determine appropriate locations for carbon storage. Could you please respond to some of the comments that have been made about whether there are appropriate locations for storage?

Mr. HAWKINS. Yes. President George W. Bush's Administration began what has been a comprehensive approach to surveying the site availability for geologic storage. And fortunately, the United States is blessed with huge amounts of the geologic formations that are appropriate for storage of CO_2. Essentially you need—as Dr. Trautz has indicated, you need a porous formation that is sufficiently below the surface of the earth to keep the injectant pressurized, and then on top of that, you need a permeable formation, and we have done surveys of the extent of these types of formations in the United States, and we have huge volumes of them, enough for more than 100 years of all current power plant emissions as was——

Ms. BONAMICI. I want to get one more quick question in to you, Mr. Hawkins. How much will the proposed CCS reduce carbon emissions if you compare a plant with CCS and compare a plant without it?

Mr. HAWKINS. If you compare it with and without, it would be about a 50 to 60 percent reduction in that power plant's carbon dioxide emissions, and that is a very substantial emission reduction and one that would demonstrate world leadership and provide a market for U.S. manufacturers as this technology was deployed.

Ms. BONAMICI. Thank you. I see my time has expired. I yield back. Thank you, Mr. Chairman.

Chairman SCHWEIKERT. Thank you, Ms. Bonamici.

Mr. MILLER. Mr. Chairman, may I respond to that first question?

Chairman SCHWEIKERT. Actually, as we work our way around, we will get there, and I appreciate some of the technical responses. Actually, I am going to give myself a few minutes here and just sort of do a little bit of digging, because I wanted to try to get my head around some of the mechanics.

And you corrected me before. Is it Trout?

Mr. TRAUTZ. It is Trautz, like the fish, spelled different.

Chairman SCHWEIKERT. That is not spelled like it. You need to change your name and spell it the right way.

Mr. TRAUTZ. It is the German spelling. Sorry.

Chairman SCHWEIKERT. In the notes on the mechanics that have been given to me, my understanding is, not too long ago in front of the Science Advisory Board at the EPA, there was a discussion that the sequestration of ACO_2 just had to sort of demonstrate the adequacy and the achievability. But yet, you know, I am being sent letters, and here is one from the American Water Works Association, and without objection, I would like to put it into the record. No objections? Oh, good. Because I always hate to object to myself. I will put that in.

[The information appears in Appendix II]

Chairman SCHWEIKERT. And part of the question they are on is saying do we really have enough data of our threat to potable water supplies, and we heard Mr. Miller talk about his experience in his state where they thought they had a saline level and it turns out it did not work. Do we have a robust literature that says what our threats are and what they are not to potable water supplies?

Mr. TRAUTZ. So the answer to the question, there have been a number of research studies that have looked at CO_2 and the potential impact if it were to leak out of a reservoir, what the potential impact would be on potable groundwater.

Chairman SCHWEIKERT. Can you answer this too? Tell me the nature of the studies

Mr. TRAUTZ. One of the studies EPRI performed, it was a field study where we actually introduced CO_2 in the dissolved phase and groundwater into a potable reservoir and looked at the impact.

Chairman SCHWEIKERT. And what scale was that done at?

Mr. TRAUTZ. It is a very small scale. It just was there to simulate hypothetical release of CO_2.

Chairman SCHWEIKERT. And when you are doing that sort of study, and this is just me sort of getting myself technically up to speed, you use actually human—I guess the term is food-quality, food-grade CO_2?

Mr. TRAUTZ. Yes, food-grade CO_2.

Chairman SCHWEIKERT. As part of your test mechanism?

Mr. TRAUTZ. That is correct.

Chairman SCHWEIKERT. And what were the conclusions? What did the model tell you?

Mr. TRAUTZ. So what happened was the CO_2 as it dissolves in the groundwater, it lowers the pH, and the pH can then start to dissolve mineral phases that are in the aquifer materials themselves and it can release heavy metals. It can also release heavy metals from the disassociation or the surface complexes that are on clays and other minerals. It can dissolve and come off of those surfaces and into solution, so heavy metal contamination is one of the biggest issues.

Chairman SCHWEIKERT. Mr. Trautz, let us say you and I tomorrow were building a modern power generation facility that was using coal. How much CO_2 would it produce for this model? Because you were telling me in northern Europe we have a couple projects that have been up and running for a while but they max out at about a million.

Mr. TRAUTZ. A million tons per year, yes.

Chairman SCHWEIKERT. And that is metric tons?

Mr. TRAUTZ. Metric tons, yes.

Chairman SCHWEIKERT. What would a modern facility produce?

Mr. TRAUTZ. Again, a 1,000-megawatt power plant, a pulverized-coal plant, would produce about 3.1 million metric tons per year and over a lifespan of 40 years, the example given in the testimony was 120 million metric tons.

Chairman SCHWEIKERT. And do we have models that would say we even have places to do such storage that we would be safe and comfortable and long after the shutting down of such a facility we would have no fissures or other——

Mr. TRAUTZ. Yes, we do have geomechanical models that can be used to predict the behavior of pressurizing a reservoir, so those are available.

Chairman SCHWEIKERT. And then to move on beyond the models, what demonstration projects do we have at scale?

Mr. TRAUTZ. As I mentioned in my testimony, on saline reservoirs only, the two that we have is the Mountaineer Project. That was about 37,000 metric tons total. And then there's Plant Barry, which is part of the SECARB Project, which EPRI is part of, and that is a little over 100,000 metric tons at this point.

Chairman SCHWEIKERT. Okay. So in many ways, our demonstrations are still sort of fractional in scale?

Mr. TRAUTZ. They are very, very fractional, yes.

Chairman SCHWEIKERT. Okay. If I were to look around the world, you are telling me right now that the largest scale we have is at a million metric tons, and that is a million metric tons on an annual basis?

Mr. TRAUTZ. That is correct.

Chairman SCHWEIKERT. And for how many years?

Mr. TRAUTZ. The Sleipner Project has been going on since 1996, so almost 20 years. It is the longest experience. The Snohvit Project has started up in 2008. The In Salah Project started up in 2008 and shut down or was suspended in 2011. We have one other large CO_2 project that is coming online that will also be a gas separation project, and that is the Gorgon Project in northwestern Australia. That will be on the order of a power plant.

Chairman SCHWEIKERT. Okay. So that we actually will have some demonstration coming on a large scale?

Mr. TRAUTZ. On natural gas, yes.

Chairman SCHWEIKERT. Why was the one shut down in North Africa?

Mr. TRAUTZ. Because the CO_2 pressure was too high and it ended up fracturing the lower part of the cap.

Chairman SCHWEIKERT. And their models didn't predict that?

Mr. TRAUTZ. No, apparently not.

Chairman SCHWEIKERT. Okay. All right. I am actually somewhat over my own time, so I am going to yield to Mr. Swalwell.

Mr. SWALWELL. Thank you, and Mr. Chair, I am moving left. I was over there, I am here, and by the end of the hearing I will be right here.

I just want to start by asking our witnesses just a yes or no, and I will go down the line and start with Mr. Hawkins. Do you agree with the 97 percent of the scientists who say with 95 percent certainty that climate change is happening as a result of activity by humans? Mr. Hawkins?

Mr. HAWKINS. Yes.

Mr. SWALWELL. Mr. Hilton?

Mr. HILTON. Yes.

Mr. SWALWELL. Mr. Trautz?

Mr. TRAUTZ. Yes.

Mr. SWALWELL. Mr. Miller?

Mr. MILLER. I am not a scientist to say yes or no on that.

Mr. SWALWELL. Okay. So I want to start, Mr. Hilton, you stated that you had concerns that DOE is out of money and does not have enough money to implement this, and were you aware that back in December they announced an $8 billion loan guarantee for these programs?

Mr. HILTON. Absolutely, but a loan guarantee doesn't give you money. It guarantees failure and recoup of the loan. The problem is to do a project and then get it financed, and you might notice, there has been no carbon capture projects applying for the $8 billion.

Mr. SWALWELL. Would hundreds of millions of dollars though, that we have for R&D that is proposed in the budget, would that be sufficient?

Mr. HILTON. Well, there is only something on the order of about less than $100 million in the CCS program. What I am talking about is the kind of programs that lead to the demonstrations like the proposed Summit Project, the projects that have been delayed, where they put, our—if you will, our project at American Electric Power. But we had $450 million but the public utility commission refused because there was no regulatory requirement to allow the utilities to recover any costs on the project, so those are the kind of funds we need and those don't exist in the DOE budget.

Mr. SWALWELL. Mr. Hawkins, does NRDC, one of the country's most respected environmental organizations, believe that there is a role for coal in our Nation's energy future, and if so, why, if not, why not?

Mr. HAWKINS. We do believe that there is a role for coal. How long that role will last is a matter of conjecture. It will, in our view, depend on a combination of factors including whether coal can be brought into the 21st century and perform as an energy resource that is consistent with our other needs: to protect our society's dependence on a stable climate. Right now, it is not consistent, and whether it becomes consistent is precisely the topic of this hearing, and we thank you for holding it.

Mr. SWALWELL. Do you think that EPA standards are putting coal plants out of business or the clean natural gas boon putting coal plants out of business?

Mr. HAWKINS. The biggest challenge to coal investments today is the marketplace. We have slack power demand, in part due to the continuing effects of the recession, in part due to good things like energy efficiency and the improved renewables production, and we have abundant, low-cost natural gas, and that makes it very difficult for investors to look at a new coal project and say this is where we should put our money. It is just not attractive.

Mr. SWALWELL. And Mr. Hawkins, do you believe that it would be appropriate for the EPA to establish standards requiring implementation of CCS at existing plants? And I draw the distinction between those plants existing now and the proposed regulations for the future.

Mr. HAWKINS. We think that CCS should be permitted as a compliance technique for any regulation of existing power plants but we have not seen an analysis that would suggest that it should be required across the board and meet economic tests.

Mr. SWALWELL. And Mr. Hawkins, how can EPA determine that a technology is adequately demonstrated if it not yet commercially available? Any thoughts on that?

Mr. HAWKINS. Yes. The difference between commercial availability and adequate demonstration is very specific to the sector that is being looked at. So commercial availability asks the question, is there a vendor that can—that is willing to provide a commercial product to a particular type of industrial source, and if there is no market for it, the answer is often no. Actually in this case, there are vendors who provide commercial carbon capture systems for power plants so in this case, there is commercial availability, there just isn't commercial use because there is no reason for the power plant operators to use it.

Mr. SWALWELL. Great. Thank you, Mr. Hawkins.

And with that, I will yield back the balance of my time.

Chairman SCHWEIKERT. Well, you don't have any more. Thank you.

Mr. Hall.

Mr. HALL. I thank you, Mr. Chairman, for holding this combined hearing and very capably so.

I appreciate hearing from the witnesses, or at least I appreciate hearing from some of them, their major concerns, not just concerns but major concerns with the proposed rule. Some of those concerns have been raised by the Attorney General of Texas. He has filed some 30 suits, I think, against this Administration, who seems like can't tell the truth, can't even call a terrorist a terrorist. But he has filed a number of suits, and not just him but the Attorney Generals from Oklahoma, Alabama, Michigan, Nebraska, South Carolina, Wyoming, in their February 28th letter to Administrator

McCarthy. Without objection, I would like to enter their letter into the record.

Chairman SCHWEIKERT. Without objection.

Mr. HALL. Thank you, sir.

[The information appears in Appendix II] MISSING

Mr. HALL. I would like to commend the Texas Attorney General one more time, Mr. Greg Abbott, who has worked tirelessly to stand up against this Administration's what we call advanced federalism. Mr. Abbott and the other states' Attorney Generals are concerned about the EPA's draft underground injection control program guidance on transitioning class II wells to class VI wells. To move it would interfere with the authority granted to the states under this program. The proposed new class of wells, class VI wells, would create new regulations in connection with prospective carbon capture and storage operations. The Attorney General's letter states, and I quote, "Notwithstanding this new class of wells intended to accommodate the underground injection of CO_2, many oil and gas producers operating class II wells have been injecting CO_2 for the past 40 years to manipulate well pressure and enhance the recovery of oil and gas. This process, commonly referred to as an enhanced oil recovery, has been used in more than 10,000 wells, about 7,000 of which are currently active, and EOR represents a critically important part of our state's and our country's energy infrastructure and plays an essential role in our Nation's economic stability and energy. The concern raised is that class II wells for EOR operations could be reclassified as class VI wells under the EPA's draft guidance, a situation that is creating an unnecessary level of uncertainty and risk to a mature area of industry that is already well regulated." So I join the Attorney General in calling for the EPA to take immediate action to rectify this situation created by the draft guidance and eliminate the uncertainty and ensure strict adherence to the applicable law. So I ask you a question, Mr. Trautz. Did I say that correctly, sir?

Mr. TRAUTZ. Trautz.

Mr. HALL. That is what I said, I thought. Sir, in your testimony you noted that geology is not uniform. What specifically are the differences in geology that might make it more or less difficult to sequester carbon in different regions of the country?

Mr. TRAUTZ. Yes, so the geology is not created equal, so to speak. If you go to the northeastern United States, there is bedrock, crystalline rocks that will not hold CO_2 capacity. There isn't sufficient capacity up in the Northeast, so they make for poor reservoirs, and there is very limited availability of storage. Go to other areas of the United States and you will find much better reservoirs like in the Southeast.

Mr. HALL. Let me ask you this. Are there parts of the country that simply does to have the geology for storage?

Mr. TRAUTZ. Yes, sir. The Northeast is one of those.

Mr. HALL. And what other options would power plants in those locations have for managing carbon dioxide? Can they simply store the CO_2 on site?

Mr. TRAUTZ. No, sir, because of the volume, but they would have the possibility of creating a pipeline that would then take that CO_2 to better storage reservoirs.

Mr. HALL. Do you think the EPA's proposed rule will put specific states and regions at a competitive disadvantage in terms of compliance?

Mr. TRAUTZ. In terms of compliance?

Mr. HALL. Yes.

Mr. TRAUTZ. No, I don't think in terms of compliance.

Mr. HALL. Well, then, let me ask you this. Do you believe CO_2 pipelines can solve this problem?

Mr. TRAUTZ. That has been one of the possible avenues, yes, sir, because we do have CO_2 pipelines that stretch down from Colorado into the Permian Basin in the——

Mr. HALL. Thank you, and my time is just about up. I would also like to note that although environmentalists are supporting EPA's proposed New Source Performance Standards rule, I would like to enter into the record an article written this week explaining the Sierra Club and the other environmental groups that are actually opposing the Kemper Project that the EPA cites as an example of CCS.

Chairman SCHWEIKERT. Without objection.

[The information appears in Appendix II] MISSING

Mr. HALL. With that, Mr. Chairman, I thank you and I yield back.

Chairman SCHWEIKERT. Thank you, Mr. Hall.

Mr. Veasey.

Mr. VEASEY. Thank you, Mr. Chairman.

I wanted to touch on a little bit what Congressman Hall was just talking about a little bit. I know that many of the witnesses today have touched on the viability of storage technology for CO_2, especially in EOR, and in Texas, you know, we have been doing this for a while, as it was already stated, particularly in the Permian Basin, and we have a complete pipeline structure that has been built around this process with the newest one being the Green Pipeline Project that was completed a short time ago transporting CO_2 from Louisiana to Texas, and the process has become so economically viable that now there is a shortage of CO_2, raising the price upwards to about $30 per ton. I wanted to ask Mr. Hawkins and Mr. Miller, while CO_2 storage may not be feasible in one area of the country as it was stated a little bit earlier, aren't there other areas such as the Gulf Coast that actually have a high need and capacity for CO_2 storage?

Mr. HAWKINS. Yes, Mr. Veasey. EOR is a great win-win-win opportunity for energy security, climate protection and I would argue for other environmental protection. We have lots of oil that is stranded in existing oil fields. It is not economic to get it out. It could be gotten out starting tomorrow if the CO_2 were available. The CO_2 isn't available because it is all going up into the air from uncontrolled industrial sources. We have an easy fix, which is to find a way of working the economics so that we put carbon capture on these power plants and then we use a pipeline network and expand pipeline networks, and the pipelining of this is easy. It is being done today. It goes hundreds of miles from southern Utah down into west Texas. It goes hundreds of miles from North Dakota up into Saskatchewan. Oil field operators are making money when the CO_2 is available. This is proven technology. And in terms of distances, you know, the idea that it might rule out some locations in the United States for coal, that just doesn't hold water. We transport coal thousands of miles from Wyoming to the southeastern United States. We can transport the CO_2 from that same coal a few hundred miles back to EOR, no problem.

Mr. MILLER. My response would be on multiple levels. Number one, natural gas, or CO_2 pipeline is feasible. Technologically, it is out there and it is happening. They are expensive. You run into some "not in my backyard" issues as you are putting in the pipeline, but they can be put in. You have—now you are transporting your CO_2 to another area so you have a variety of environmental liabilities that you are going to be taking on and moving to another area of the country and so there is liability that goes back to your community.

And then finally, on the EOR side—and this is not my specialty but what I have been reading on that is, CO_2 is a very expensive product and people are buying that and they are using that as a working fluid, but they are capturing that CO_2 back out and continuing to use that as a working fluid. So it is not really a sequestration technology, it is a technology that is used to capture energy and recover energy and gas, so I don't see EOR as sequestration as much as a use of the CO_2, and that is what is driving up the costs. They are trying to get that. They are using that fluid. But once they inject it in, they try to get that back out so they can use it again.

Mr. VEASEY. I think that both of you would agree that Texas has had a long history of using CO_2 in plugged oil wells with very little environmental damage, and wanted to ask you specifically about the regulations for EPA's New Source Performance Standards. Based on what we heard from Mr. Hawkins just a second ago, wouldn't there—wouldn't we create more of a market under these regulations for CO_2?

Mr. HAWKINS. Well, I think there would. The recycling that the witness mentioned is correct but it is only a fraction. About 30 percent of the injected CO_2 comes up in the oil, and industry practice is to put that back down. But there is a net additional injection of about 50 million tons a year now, so it is storing lots of CO_2, and yes, the oil industry would love to have additional supplies of CO_2 but we have a disconnect in the marketplace because there is no policy requirement to capture CO_2, and given the other aspects of the marketplace, there is no economic rationale because the costs of capture are high enough that you can't earn money back in the typical situation for selling it for EOR. Now, there are some niche situations where you may be able to make a profit even today without a regulation, but to make this expand, you will need regulations to drive it.

Mr. VEASEY. Thank you. Thank you, Mr. Chairman.

Chairman SCHWEIKERT. Thank you, Mr. Veasey.

Mr. Rohrabacher.

Mr. ROHRABACHER. Thank you very much.

First and foremost, we need to recognize that this debate, this discussion is predicated on certain premises that I disagree on, and those of us who think that the concept of global warming is fraudulent and that it has not been proven, we obviously are much more—those of us who don't accept the idea that there are—for example, when we hear that 97 percent of the scientists, we hear something like that quoted, we go my goodness, do 97 percent of the scientists believe that? Well, I am sorry but 97 percent of those scientists who replied from that questionnaire said that, not 97 percent of all the scientists as we hear repeated over and over again. It used to be repeated that we had global warming and now it is called climate change because it didn't get any warmer. We in fact had all of the people, those of us who have been around long enough to remember how adamant it was that there was going to be a 5-degree jump in the temperature over the last 15 years, and instead we have had absolutely flat temperatures. So there is a premise that those of us on this side may disagree that maybe the whole basis of the discussion is wrong but let us get into the debate of the discussion today, which is we are talking about CO_2 and the sequestration that is being pushed on us in the name of stopping global warming where they now call it climate change because the global warming stopped 15 years ago.

The gentleman from Texas just presented us a good picture of how in Texas they are utilizing CO_2 in the production of oil. Now, let me ask the panel: If we then change the nature of the CO_2 from being a natural source of CO_2 put into the ground and we now are mandating that it is a byproduct of coal, the use of coal, that CO_2, doesn't that change the regulatory mandates that the industry has to put up with and wouldn't that so dramatically change those regulatory mandates that it would make it almost impossible then to use even the coal that is our—even the CO_2 that is now being used by the industry if you would intermix the CO_2 from coal production with natural CO_2? Does anyone on the panel know anything about that?

Mr. HILTON. I think that the issue that you are addressing, sir, is, what has been expressed by people like Denbury is, you know, they would not choose to overlay the costs and the difficulty of subpart RR in regulations and they would—if they continued to use natural CO_2, they are subject to those regulations.

Mr. ROHRABACHER. Right.

Mr. HILTON. But if they were to bring in any CO_2 from a power facility, they would become subject to those regulations, and as I said, Denbury has issued a public statement saying that they would not use that because of cost and the impact on operations.

Mr. ROHRABACHER. So what we just heard from our very sincere colleague from Texas about—it would destroy the very thing that you are bragging about. The fact is, it would put a whole new regulatory burden just to utilize this CO_2 byproduct of coal production into the natural CO_2 would prevent or at least dramatically increase the cost of the very thing that you were talking about, which is CO_2 is used now by the oil industry.

Yes, sir, go right ahead.

Mr. HAWKINS. Yes, Mr. Rohrabacher. Let me read a very short sentence from the Denbury Web site. "CO_2 EOR is increasingly being viewed as a strategy to reduce carbon emission from various current and proposed industrial facilities. Our CO_2 process provides an economical and technically feasible method of CO_2 disposal." So Denbury is holding itself out as being a source for disposal of industrial CO_2, and we don't think it is sustainable for them at the same time to say if they are required to report on what happens to that CO_2, they will refuse this business. We just don't think that washes.

Mr. ROHRABACHER. Well, we don't think it washes, but obviously there are a lot of people in business who have to put up with the regulations and the bureaucrats and the mandates and the government intrusions into the decision-making and the extra costs that government mandates will have have said we are concerned about that, and actually you are bringing a whole new set of fundamental laws that have to be dealt with by combining natural CO_2 with a byproduct of coal. All of a sudden CO_2 then is treated not as a natural material but as some sort of a toxic substance. As a toxic substance, it is highly regulated and a situation that would add dramatically to the cost and complication of doing business.

Of course, it would be very well intended. Obamacare was very well intended as well. Thank you very much.

Chairman SCHWEIKERT. Thank you, Mr. Rohrabacher.

Mr. Neugebauer.

Mr. NEUGEBAUER. Thank you, Mr. Chairman, and thank you for holding this joint hearing.

Mr. Miller, you know, this panel and previous panels have testified pretty consistently that CCS is not adequately demonstrated and not necessarily completely commercially available. So if that is the fact, then what are the implications for your customers, you know, City Utilities, retire older plants and need to add new sources of power? What is going to be the consequence if EPA moves forward with these regulations?

Mr. MILLER. Well, it could go a variety of directions but ultimately we have the obligation to serve our customers, and as a municipal utility, the money we spend is not shareholder money, it is our customer money, and so first of all, if we are in a retirement mode where we retire assets, it was mentioned earlier that some assets will be retired before the end of their useful life but you are still paying on those. Your customers have paid for those assets, so that is a loss of money there. Now you have to find either the ability to install not demonstrated technology—and I have been on the end where I have had to install demonstrated technology, whether it be a scrubber or selective catalytic reduction, and you buy those from vendors that are commercial. They have guarantees, and they are designed by nationally recognized engineers, and when you go to install those, you get surprises. Even commercial equipment, you still get surprises and there are some additional costs, and those costs flow back to your customers. So you are going to—our customers will pay more because you have assets that are retiring. You are putting in non-proven, non-demonstrated technology which ups the amount of risk that you are going to take on that you are going to find problems as you implement that technology, and that is cost. So those are all driving cost, increasing cost to customers, and so whether you buy it from the market or whether you install the technology that is not demonstrated, and when you retire the assets, that all flows back in our case right back to our customers. And so we are very protective of that because we have that obligation to serve, and they own us.

Mr. NEUGEBAUER. And so the next step of that is, okay, so you have those options out there, assuming that you have those options, it could increase the cost because of the increased cost in technology. Here is my question: If we keep going down this path of, you know, being anti-fossil fuel for the production of electricity in this country, whether it be coal or natural gas, you know, doesn't that begin to limit our options? In other words, your utility is not the only utility in the country that is, you know, facing this issue, and so we this massive consolidation of all these different communities or providers for communities looking for power sources, and if we begin to limit the choices, how do we keep the lights on?

Mr. MILLER. You are basically shrinking your subset of options, and these—as was mentioned earlier, it takes a long time to get these generating sources on and up and operating, and so you start limiting your capacity and you start running the potential of having reliability problems, not only in your region—or in your area but in the region, and you are putting a lot of pressure on these much reduced options available to your customers.

So the answer is, we still have that obligation to serve. We are still going to do everything we can but you increase your risk of reliability issues across the Nation, and it also drives costs into the business world, and so your economic development picture changes too. Instead of adding jobs in your community, you might be freezing jobs or you might be reducing jobs or moving them elsewhere. So it impacts our low-income customers but it also impacts our economic development within our communities.

Mr. NEUGEBAUER. Mr. Miller, you were reading my mind because the next question I have is, okay, so we have got reduced capacity so we got a reliability factor and probably got a lot of price pressure then because you have got all of these people competing that have these contracts to deliver power, and they are looking for that power. And so the question is—and you mentioned it—is that, you know, job creation, you know, the impacts on businesses, manufacturing businesses, all kinds of business. It is pretty hard to run a business in this country without power.

And so that is the reason I am going to ask unanimous consent, because Heritage just recently did a study that I think is important to the record, Mr. Chairman, and I will just read a little bit from that. It said that according to the report, by 2023 we can expect to see nearly 600,000 jobs lost nationwide with Texas losing 25,000 jobs and over 330,000 manufacturing jobs could be lost because of this rule, and in my district alone we could expect to see maybe 400 people lose their job. So without objection, Mr. Chairman, I would like to put the Heritage report as a part of the record.

Chairman SCHWEIKERT. Any objections? So ordered.

[The information appears in Appendix II]

Mr. NEUGEBAUER. And I yield back the time I don't have.

Chairman SCHWEIKERT. Thank you, Mr. Neugebauer.

Mr. Cramer.

Mr. CRAMER. Thank you, Mr. Chairman, and I thank the witnesses for your testimony today.

Before I forget, I want to do it right upfront or I almost certainly will, I want to place into the record without objection a letter from the North Dakota Industrial Commission that represents their comments on this rule. The Industrial Commission of North Dakota is made up of three separate elected officials who come together on the Commission. They are the Governor, the Attorney General and the Commissioner of Agriculture. So I would like to place that in the record.

Chairman SCHWEIKERT. Without objection, so ordered.

[The information appears in Appendix II]

Mr. CRAMER. Before I speak about what the Commission has written about, I am very pleased to know, Mr. Hawkins, that the Natural Resource Defense Council supports interstate pipelines, international pipelines even. Your reference to the CO_2 line from the Dakota gasification facility in North Dakota, which I helped site when I was on the Public Service Commission, to Weyburn, Canada, for enhanced oil recovery—by the way, when we sited it, we had a hearing and not a single person showed up. That is the way it is in North Dakota with good ideas.

And so I am—however, your comment that pipelining is easy, I have to take some exception with. If building international and interstate pipelines was easy, we would have a lot more of them right now. We would have——

Mr. WEBER. Like Keystone.

Mr. CRAMER. Yes, for example. By the way, Chairman Hall, North Dakota's Attorney General is engaged so far in 12 separate lawsuits against their federal Government, the EPA.

In the comments that the Industrial Commission writes that North Dakota really focuses on this issue of CO_2 as an asset. It is an asset. It is a resource. The EPA treats it as waste, same with the pore space. We treat it as an asset. The EPA treats it as waste and consequently there is tremendous regulatory confusion as a result, and so I know I might be a little redundant but I want to flesh this out even a little further. Maybe, Mr. Trautz, you could help me with this. Mr. Hilton made reference to it earlier. Can you describe the requirement that EOR operators, you know, have to operate under differently than, say, traditional sequestration? Can you maybe flesh that difference out a little bit for us so that I have a better scientific understanding and why should it be that way, if you think it should or why it shouldn't.

Mr. TRAUTZ. The difference between the reporting requirements on the greenhouse gas mandatory reporting requirement is under Subpart RR. That is for geologic storage or sequestration. There is a—sort of a burden of proof that you have to do a mass balance on the CO_2 that you put into the ground. You have to ensure or at least look at, put through a monitoring program that it isn't coming back up to the surface.

Mr. CRAMER. Um-hum.

Mr. TRAUTZ. Under Subpart UU it is—the burden of proof is frankly not even there. It is really just monitoring the CO_2 that goes into the field, as well as fugitive emissions from your operations or facilities, so there isn't the same level of reporting that is required in certainly monitoring.

Mr. CRAMER. Maybe, and this could be for all of the panelists because there was reference earlier to previous rules and previous technological advancements. I think mercury was specified, I think some of the others, I mean SOx, NOx. Is the commercially available or perhaps even the standard adequate demonstration of technology equal in this case in carbon capture as it was then with mercury and others, anybody or all of you? Mr. Hilton?

Mr. HILTON. Congressman, I can really address that. The answer is we were doing the technologies required either not in this country or in other industries that everything that was—that has been required under the Clean Air Act except for this. I mean, as I pointed out, we did scrubbers. The first scrubbers were at Battersea and Bankside, and they were there to protect the erosion of, you know, all of the buildings there. So we built these things for years.

And as I said, I worked on my first one before the Clean Air Act existed. So I mean it is—you know, we have done these things. NOx reduction was developed in Japan, not here, but the technology was there. And I know because my company was a licensee of those companies.

And so this is the first time we are dealing with something where we have nothing out there to show. And, you know, we are running down a path where Europe is not pushing this issue, China is not pushing this issue, India. We are alone out here. And so the technology has got to be developed here, you know, because—so I think, you know, this is the first issue where we haven't had the ability to—like in waste and energy where we had full-scale plans on mercury in the '80s.

Mr. CRAMER. Well, I thank you. I look forward to the day when the technology does catch up because I would love to burn more than, you know, that 30 million tons of coal we burn in North Dakota every year. We have an 800-year supply of it, so I would like to burn it for 800 years and use it to get even more oil out of the ground. That is a noble goal.

Thank you.

Chairman SCHWEIKERT. Okay. Thank you, Mr. Cramer.

Mr. Hultgren.

Mr. HULTGREN. Thank you, Chairman. Thank you all for being here today for this really important hearing as we continue to assess technology as well as increased cost that EPA is mandating on the American people.

While the Administration and EPA continue pushing for the uncertainty of a closed-door regulatory approach as opposed to the balanced long-term solution our legislative body is supposed to provide for the American people, it is crucial that Members of Congress understand the technologies being mandated, as well as how EPA made their decisions.

While it is often hard even for Members of Congress to get answers from EPA, we unfortunately are the ones that have to go home and explain to our constituents what many see as unjustifiable. I am certainly glad to have such a diverse panel before us today, and it will be beneficial to have experts before us that understand the technology and can explain to us the process and hurdles of energy technology innovation.

Mr. Hilton, I wanted to address my comments and questions to you if I may. Just to get an idea about how long the technology development process takes for energy technologies, I would like to discuss one of your projects with DOE that you briefly touched on in your testimony, the chemical looping combustion prototype for CO_2 capture with the National Energy Technology Laboratories.

I know that in December 2012 NETL technology readiness assessment for the Clean Coal Research Program, your chemical looping combustion prototype was given a technology readiness of five out of nine. I wonder if you could explain to the Committee what a technology readiness level is and wondered if you could also talk about how valuable TRL is in assessing the viability of technology to perform on a commercial level.

Mr. HILTON. Well, it is basically assigning a level. There are characteristics to each level and assign how you move through the development into what is ultimately a commercially viable product. And chemical looping—and we really started on this and it depends when you really want to trace the roots, but let's say we started in earnest in chemical looping as we know it now in the '90s, and if all goes well, we expect it to be commercial in the early '20s, 2020, because what we have to do is solve the problems of chemical looping, moving the solids around, extracting the solids, extracting the CO_2, auto thermal ignition, you know, because in early stages you provide the heat to make things work.

So you get through this and then you have to bring them up from our current 3 megawatt unit to a 50 megawatt unit hopefully to something larger and eventually a full-scale because, as I said, when we go full-scale commercial, to get to that last level, that is what DOE and everybody else wants to see. So it is a long process in our industry.

Mr. HULTGREN. Yeah. I want to follow up on that a little bit. You mentioned the '90s. It is my understanding that your technology started bench tests in 1996. What would be the expected time frame for a project such as this? Could you go from bench testing to demonstration and then final commercial sale? Is that the 2020 number that you would say, so basically a 25-year to 30-year process?

Mr. HILTON. That is pretty typical—

Mr. HULTGREN. Okay.

Mr. HILTON. —for a process like this.

Mr. HULTGREN. And how often do technologies get the prototype scale before realizing they will not work on the commercial level?

Mr. HILTON. More often than I would like to admit to, but R&D is—you know, it is kind of—to not have failure in R&D is just—is not an option—

Mr. HULTGREN. Right.

Mr. HILTON. —I mean because it wouldn't be R&D. You would already know the answers.

Mr. HULTGREN. Right. Since EPA is charged with determining whether a technology has been adequately demonstrated and DOE already has a process in place to assess technology readiness levels, it seems to me that EPA should rely heavily on the scientists who understand the technology. At what TRL would you consider a technology to be adequately demonstrated?

Mr. HILTON. Essentially, it should be toward the upper level of nine. I mean that is when you know things work and that is when you have built something that is large enough to say that this is something that can be applied.

Mr. HULTGREN. Okay. Well, thank you very much. Mr. Chairman, I yield back the balance of my time to the Chairman if you have any other questions. Otherwise, I would yield back my time.

Chairman SCHWEIKERT. Thank you, Mr. Hultgren.

Mr. Weber.

Mr. WEBER. Thank you, Mr. Chairman.

EPA claims that enhanced oil recovery will bring costs down for power plants and for domestic energy reduction, but the reporting requirements on EOR operators will make it prohibitive for these companies to use CO_2 from any future coal-fired power plants. These requirements will in fact inject, no pun, or maybe I should say pun intended, the EPA into a process that has long been successfully regulated by the states, especially my State of Texas.

As our colleague over there, dare I say on the right; I should say over on the left, Marc Veasey, alluded to. CO_2 has been used for over 40 years in enhanced oil recovery. According to a detailed white paper, Mr. Chairman, which I have here from Denbury Resources, an EOR operator located in Texas, "the proposed NSPS rule will foreclose, not encourage"—I repeat—"will foreclose, not encourage the use of CO_2 captured by emission sources in EOR operations."

And, Mr. Chairman, I would like to submit this white paper into the record.

Chairman SCHWEIKERT. Without objection.

[The information appears in Appendix II]

Mr. WEBER. Thank you.

Denbury Resources does use enhanced oil recovery, captured CO_2. I have the—and that I know of, the largest and only CCS carbon capture and sequestration storage facility in my district in Texas, Port Arthur. It is—it was built/managed by Air Products at a cost of about $400 million. Sixty-six percent of the funding came from the Department of Energy or the American Reinvestment and Recovery Act, 66 percent of the funding.

Now, if you read Air Products' news release on May the 10th, 2013, about that, let me quote from their product—their press release. "This unprecedented achievement comes by way of an Air Products innovative technology is the first of its kind operating at such a large scale"—and here is the key phrase—"and has not been accomplished anywhere else in the United States." Further, down here they read—it says, "this project"—they state that this project "would not have been achievable without the support and involvement of the Department of Energy."

To call this something that is capable of being duplicated in a viable process in the United States is a laugh. It is an absolute laugh. For the witnesses, are there any of you all who get 66 percent funding in your salary or that would admit it?

Let the record show there is none, Mr. Chairman.

Are any—there are. We have business people at the table, right, that are in business. Any of you all whose businesses get 66 percent funding from the federal Government and would admit it?

Let the record show there are none.

Kemper, the project over in Mississippi, Kemper County, Southern Energy, the CEO came to the House Environmental Action—Energy and Action Team, which I am a member of, and testified some months—last year some months back and he said it is such a huge cost overrun and it is not applicable in—anywhere else in the United states. And that is with Denbury having a pipeline right in their backyard so to speak, which, fortunately comes over into my district in Texas.

Am I losing my microphone? No.

So for us to say that this is duplicable and that this has been demonstrated as a—capable of being duplicated process, for the EPA to say that is unbelievable in my opinion.

We have seen from testimony today the prices for energy—Mr. Miller, for your customers, those that—as what Chairman Lummis said, demonstrably at the lowest economic rung will negatively impact those customers. Do you agree with that?

Mr. MILLER. Yes, sir, I do.

Mr. WEBER. You know, it seems to me it is irony of all ironies. We have got tax dollars, 66 percent of the project that the EPA alludes to, by the way, funding a process that we cannot duplicate that is going to hurt, you want to give new meaning to the term double jeopardy. We are using taxpayer dollars to fund a process that is going to hurt those who can least afford it at the bottom rung, maybe triple—let me just say maybe triple jeopardy.

I would submit for this panel, for this body that we are going to jeopardize, number one, those who can least afford the energy cost. We are going to jeopardize investment. There will be no new jobs at a time when we need it, and we are going to jeopardize our national security because we are going to need energy to operate the things, our military. We are going to need energy to produce goods, products, services, and we are going to be triple jeopardized by trying to do this process the very economy in the greatest country in the world that is great, and I would ask any of you to disagree because we have the most solid, most affordable, most reliable, best supply of energy on the planet and we worked hard to get it that way. And this is going to undermine the very process. Does anybody disagree with that?

Mr. HAWKINS. I disagree.

Mr. WEBER. You—that——

Mr. HAWKINS. I disagree that it will undermine all——

Mr. WEBER. I know. Well, I am—Mr. Hawkins, I am so glad you are here, glad to hear that, as my colleague over here said, you support pipelines. You said in your statement earlier that these regulations would help oil companies operate more profitably. I am so glad you are concerned about the oil companies. That is just something that is very admirable on your part.

And, Mr. Chairman, I have gone over my time so I yield back what I don't have.

Chairman SCHWEIKERT. Thank you, Mr. Weber.

Mr. WEBER. Thank you.

Chairman SCHWEIKERT. Mr. Bridenstine.

Mr. BRIDENSTINE. Mr. Hawkins, I just wanted to ask, can you explain a little bit about how EOR offsets the cost of carbon capture and storage?

Mr. HAWKINS. Yes. Currently, oilfield producers pay suppliers of CO_2 that—they buy the CO_2; they use it for injection. I don't know what the current price—going price is but it is more than $12 a ton of CO_2, something like that. It might be as high as $20 a ton. Contracts sometimes specify it as a percentage of the price of oil, so as the price of oil goes up, the price that is being paid for CO_2.

So the proposed builders of power plants like the Summit power plant project in Texas are negotiating arrangements with off-takers of that CO_2.

Mr. BRIDENSTINE. Is the regulation required to enhance that market for the carbon dioxide?

Mr. HAWKINS. Either regulation or lots of money that we don't have is required because the market will not support it given the current market structure.

Mr. BRIDENSTINE. Is that an official policy of NRDC?

Mr. HAWKINS. Which aspect, sir?

Mr. BRIDENSTINE. The regulation would be required to create the market for the CO_2 for EOR.

Mr. HAWKINS. That is our belief that—based on an analysis of market conditions that it won't happen without a requirement.

Mr. BRIDENSTINE. Can you share with me the difference between a Class II well and a Class VI well?

Mr. HAWKINS. I would be happy to provide you with our comments on Class II and Class VI, yes.

Mr. BRIDENSTINE. I have a document here from NRDC that suggests that Class II wells are insufficient for EOR but certainly Class VI wells would be better? But it seems like there aren't very many, if any, Class VI wells, is that correct?

Mr. HAWKINS. Our position is that for geologic sequestration activities where the company is proposing to permanently retain the CO_2 underground, there ought to be some demonstration beyond what is required under current Class II rules that the CO_2 will actually stay underground. That is our position.

Mr. BRIDENSTINE. So on the one hand we need EOR to make the market for CO_2 viable; on the other hand, we want to severely limit EOR for the extraction of oil, is that correct?

Mr. HAWKINS. No, it is not correct, sir. Requiring companies to do reasonable monitoring and reporting will increase confidence that this——

Mr. BRIDENSTINE. But the reality is——

Mr. HAWKINS. If I might finish, it will increase confidence in the public that this is in fact a secure solution and that the operators are behaving responsibly.

Mr. BRIDENSTINE. If you limit EOR, it cannot be used to offset the cost of carbon capture and storage.

And, Mr. Chairman, I would like to submit this document from the NRDC as far as the difference between Class II and Class VI wells and why NRDC seems to believe that it is necessary to limit EOR.

[The information appears in Appendix II]

Mr. BRIDENSTINE. I would like to just, I guess, ask the panel. Mr. Miller, if you would share with me as somebody who operates utilities. We have an issue in my State of Oklahoma where, you know, we are literally closing down coal-fired power plants, and it is going to cost consumers in my district in the Tulsa area. We are going to see rates go up. Some people are saying it is going to go up six percent, some people are saying 20, some people as much as 40 depending on the time horizon. Over the next 10 or 20 years it is going to be a significant increase.

The challenge here is that coal is stable, the price is stable, and natural gas, we are seeing spikes across the country in very specific regions when it gets cold, which it still does get cold in places. In New York we saw it, the price of natural gas went up to, you know, over $90 in certain areas. That creates a huge risk in my opinion, $90 per thousand cubic feet. It is a huge risk. In Colorado it went up recently, you know, $45 per thousand cubic feet. This is now something that we are going to have to deal with in Oklahoma because of the shuttering coal-fired power plants. Would you share with me your thoughts on that?

Mr. MILLER. Well, we just experienced that in your state. In our region just a week or so ago we had a cold spell and there were plants that were supposed to run during that coldest day going from Sunday into Monday, and when they went to run, there wasn't enough gas supply.

So within our region, Oklahoma, Missouri, and Arkansas area, we had plants—we had up to 1,700 megawatts that were supposed to run that they—that did not, and then we saw natural gas prices go from about $5 up to $20 plus for a couple days in a row and it was because we had constraints in pipeline and we had generating units that couldn't run because we didn't have the gas that can be delivered to them.

And as we see more of these regulations come on in 2015 and '16, you will see a more generation—coal generation come off-line, but I am not sure where that capacity is to replace it. So we will be feeling the pressure within the marketplace over the next few years.

Mr. BRIDENSTINE. Thank you. I yield back.

Chairman SCHWEIKERT. Thank you, Mr. Bridenstine.

Ms. Bonamici had something quick she wanted to share.

Ms. BONAMICI. Thank you very much, Mr. Chairman.

As we conclude the panel, I wanted to thank every one of you for coming here today to inform us.

I also wanted to say something about a comment that was made earlier about thanking or appreciating only some of the witnesses today. All of you have spent a lot of time preparing for this hearing, traveling here to inform us, to share your years of expertise, and even though every one of us might not agree with everything that every one of you said, you all deserve to be thanked and appreciated.

Thank you, Mr. Chairman. I yield back.

Chairman SCHWEIKERT. Thank you, Ms. Bonamici.

And I want to thank the witnesses for their testimony and the Members for their questions. And we will ask you to respond to those questions in writing.

You know, there are so many things—this is one of those I wish I could have a day with no one else because there are so many odd technical things I would like to understand of, you know, the optionality that is available in these technologies, what is robust, what isn't, and even just the whole discussion on EOR and the practicalities of how do you both incentivize that but at the same time do some of the regulatory approaches, do we change the cost structure in a way where we lose that opportunity?

So with that, this panel is dismissed. Thank you for your valuable time today.

I think we are going to take about 90 seconds and everybody grab a cup of coffee and we will move on.

Okay. I would like to introduce our second panel, which is—and it is pronounced McBride?

Ms. MCCABE. McCabe.

Chairman SCHWEIKERT. McCabe, sorry.

Our second panel witness is Janet McCabe, Acting Assistant Administrator of the Office of Air and Radiation in the Environmental Protection Agency. Previously, she was at the Office of Air and Radiation, Principal Deputy to the Assistant Administrator. Prior to joining the EPA, Ms. McCabe was the Executive Director of Improving Kids' Environment, Inc., a children's environmental health advocacy organization. She also previously served in several leadership positions in the Indiana Department of Environmental Management Office of Air Quality.

Ms. McCabe, you have five minutes. You know the routine, yellow light, talk faster.

TESTIMONY OF JANET MCCABE, ACTING ASSISTANT ADMINISTRATOR, OFFICE OF AIR AND RADIATION, U.S. ENVIRONMENTAL PROTECTION AGENCY

Ms. MCCABE. All right. Thank you, Mr. Chairman.

Chairman Schweikert and in absentia Chairman Lummis, Ranking Members Bonamici and Swalwell, and Members of the Committee, thank you for the opportunity to testify today.

Climate change is one of the greatest challenges of our time. Our changing climate already threatens human health and welfare and economic well-being through the increased intensity and frequency of severe heat waves, a rise in sea level affecting our coastal businesses and communities, and a combination of rising temperatures and changing precipitation that leads to increased droughts and wildfires. If left unchecked, climate change will have devastating impacts on the United States and on the planet.

Last June, President Obama issued a national Climate Action Plan directing the EPA and other federal agencies to take steps to mitigate the current and future damage caused by greenhouse gas emissions and to prepare for the climate changes that have already been set in motion. Climate change is also a global challenge, and the President's Plan recognizes that the United States must couple action at home with leadership abroad.

Today, you have asked me to focus on the critical role EPA plays in implementing one of the central activities in the Climate Action Plan: cutting carbon pollution from new power plants. In March of 2012, the EPA first proposed carbon pollution standards for future power plants. After receiving over 2.5 million comments, we issued a new proposed rule based on this input and on updated information.

In September of 2013, the EPA announced its new proposal. The proposed standards would set the first uniform national standards for carbon pollution from future power plants. They will not apply to existing power plants. The proposal would set separate national limits for new natural gas-fired turbines and new coal-fired units.

These standards, which are proposed under Section 111 of the Clean Air Act, are based on an evaluation of the technology that is available to limit carbon pollution emissions at new power plants. EPA proposed these standards by following a well-established process to determine the "best system of emission reduction, adequately demonstrated" to limit pollution, otherwise known as BSER.

These proposed standards reflect the demonstrated performance of efficient, lower carbon technologies that are currently being used today. They set the stage for continued public and private investment in technologies like efficient natural gas and carbon capture and storage. The proposal was published in the federal Register on January 8, and the formal public comment period is now open. In fact, the EPA recently extended the comment period to May 9 to ensure that we get as much public input as practicable. We look forward to robust engagement on the proposal and will carefully consider the comments we receive as a final rule is developed.

As noted, the proposed rule would apply only to future power plants. For existing plants, we are engaged in extensive and vigorous outreach to a broad group of stakeholders, including states, who can inform the development of proposed guidelines. EPA expects to issue these proposed guidelines by June of this year.

These guidelines will provide guidance to states, which will have the primary role in developing and implementing plans to address carbon pollution from the existing plants in their states. We recognize that existing power plants require a distinct approach, and this framework will allow us to capitalize on state leadership and innovation while also accounting for regional diversity and providing flexibility.

Responding to climate change is an urgent public health, safety, national security, economic, and environmental imperative that presents great challenges and great opportunities. As the President and Administrator McCarthy have stated, both the economy and the environment must provide for future and current—current and future generations. We can and we must embrace cutting carbon pollution as a spark for business innovation, job creation, clean energy, and broad economic growth.

The continued global leadership of the United States and the success of the Clean Air Act over the past 40 years make it clear that public health protection and economic growth go hand in hand.

Thank you again for the opportunity to testify, and I look forward to answering your questions.

[The prepared statement of Ms. McCabe follows:]

Opening Statement of Janet McCabe
Acting Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency

Hearing on the Science of Capture and Storage: Understanding EPA's Carbon Rules

Subcommittee on Energy and Subcommittee on Environment
Committee on Science, Space, and Technology
U.S. House of Representatives
March 12, 2014

Chairmen Schweikert and Lummis, Ranking Members Bonamici and Swalwell, members of the Committee: Thank you for the opportunity to testify today.

Climate change is one of the greatest challenges of our time. Our changing climate already threatens human health and welfare and economic well-being, through the increased intensity and frequency of severe heat waves, a rise in sea level affecting our coastal businesses and communities, and a combination of rising temperatures and changing precipitation that leads to increased droughts and wildfires. If left unchecked, continued emissions of greenhouse gases and the resulting, measurable increase of their concentration in the atmosphere will have devastating impacts on the United States and the planet. Reducing carbon that is being emitted into the atmosphere is critically important to the protection of Americans' health and the environment upon which our economy depends.

Last June, President Obama issued a national Climate Action Plan, which directs the EPA and other federal agencies to take steps to mitigate the current and future damage caused by greenhouse gas emissions and to prepare for the climate changes that have already been set in motion. A key element of the plan is addressing carbon pollution from new and existing power plants in the United States. Our changing climate is also a global challenge, and the President's Plan recognizes that the United States must couple action at home with leadership abroad.

Cutting Carbon Pollution

Today you have asked me to focus on the critical role EPA plays in implementing one of the central activities in the Climate Action Plan: cutting carbon pollution from new power plants.

Power plants are the single largest source of carbon pollution in the United States, accounting for roughly one-third of all domestic greenhouse gas emissions. In March of 2012, the EPA first proposed carbon pollution standards for future power plants. After receiving over 2.5 million comments, we determined to issue a new proposed rule based on this input and on updated information.

In September of 2013, the EPA announced its new proposal. The proposed standards would set the first uniform national standards for carbon pollution from future power plants. They will not apply to existing power plants. The proposal would set separate national limits for new natural gas-fired turbines and new coal-fired units. New large natural gas-fired turbines would need to emit less than 1,000 pounds of CO2 per megawatt-hour, while new small natural gas-fired turbines would need to emit less than 1,100 pounds of CO2 per megawatt-hour. New coal-fired units would need to emit less than 1,100 pounds of CO2 per megawatt-hour. Operators of these units could choose to have additional flexibility by averaging their emissions over multiple years to meet a somewhat tighter limit.

These standards, which are proposed under Section 111 of the Clean Air Act, are based on an evaluation of the technology that is available to limit carbon pollution emissions at new power plants. EPA proposed these standards by following a well-established process to determine the "best system of emission reduction ... adequately demonstrated" to limit pollution, or BSER.

In the proposal, the EPA determined that the best system of emission reduction for new coal units is a new efficient unit implementing partial carbon capture and storage (CCS). The EPA based this determination on a review of (1) existing projects that implement

CCS; (2) existing projects that implement various components of CCS; (3) planned CCS projects; and (4) scientific and engineering studies of CCS. The determination relies on a wide range of data, information, and experience.

These proposed standards reflect the demonstrated performance of efficient, lower carbon technologies that are currently being used today. They set the stage for continued public and private investment in technologies like efficient natural gas and carbon capture and storage. The proposal was published in the Federal Register on January 8, and the formal public comment period is now open. We recently extended the comment period, to May 9, to ensure we get as much public input as practicable. We look forward to robust engagement on the proposal and will carefully consider the comments we receive as a final rule is developed. We continue to review information as it becomes available as well, working with the Department of Energy and other agencies with expertise in these issues. We know there is great interest in our proposal, and great interest in our review of CCS. These opportunities for discussion and making sure EPA has the best information available are what the notice and comment process is all about.

As noted, the proposed rule would apply only to future power plants. For existing plants, we are engaged in extensive and vigorous outreach to a broad group of stakeholders, including states, who can inform the development of proposed guidelines. EPA expects to issue these proposed guidelines by June of this year. These guidelines will provide guidance to States, which will have the primary role in developing and implementing plans to address carbon pollution from the existing plants in their states. We recognize that existing power plants require a distinct approach, and this framework will allow us to capitalize on state leadership and innovation while also accounting for regional diversity and providing flexibility.

Conclusion

Responding to climate change is an urgent public health, safety, national security, economic, and environmental imperative that presents great challenges and great opportunities. As the President and Administrator McCarthy have stated, both the economy and the environment must provide for current and future generations. We can and we must embrace cutting carbon pollution as a spark for business innovation, job creation, clean energy, and broad economic growth. The continued global leadership of the United States and the success of the Clean Air Act over the past 40 years make it clear that public health protection and economic growth go hand in hand.

Thank you again for the opportunity to testify. I look forward to answering your questions.

Janet McCabe, Acting Assistant Administrator for the Office of Air and Radiation

Janet McCabe is the Acting Assistant Administrator for the Office of Air and Radiation, having previously served as OAR's Principal Deputy to the Assistant Administrator.

Prior to joining EPA in November 2009, McCabe was Executive Director of Improving Kids' Environment, Inc., a children's environmental health advocacy organization based in Indianapolis, Indiana and was an adjunct faculty member at the Indiana University School of Medicine, Department of Public Health.
From 1993 to 2005, Ms. McCabe held several leadership positions in the Indiana Department of Environmental Management's Office of Air Quality and was the office's Assistant Commissioner from 1998 to 2005. Before coming to Indiana in 1993, Ms. McCabe served as Assistant Attorney General for environmental protection for the Commonwealth of Massachusetts and Assistant Secretary for Environmental Impact Review.

Ms. McCabe grew up in Washington, D.C. and graduated from Harvard College in 1980 and Harvard Law School in 1983.

Chairman SCHWEIKERT. Thank you, Ms. McCabe. And you just did that very efficiently.

And going over your testimony, can I drill down on just a couple of things I had some curiosities on? As you head towards, what is it, the May 9 ending of public comment——

Ms. MCCABE. Right.

Chairman SCHWEIKERT. —you actually had the discussion of demonstrated technologies, particularly as we speak of the ACO_2 standards. And some of this I know I am asking for sort of technical observation, but in the previous panel there was a lot of concern on the quality of demonstration, demonstration at capacity, demonstration at stress, demonstration of saline and other types of sequestration. Yet the rule set that you have produced basically in many ways is written as if the demonstration is done, that the technology is robust and ready to go, and yet the previous panel was pretty crisp even from right to left that there is still some real concerns on the technology itself. How do you do the rule set in that environment?

Ms. MCCABE. Well, that goes to the heart of the proposal, Mr. Chairman. We do believe that the proposal we put forward meets the requirements of the Clean Air Act for determining technology that is appropriate. And I want to clarify that what we do in a New Source Performance Standard is we set a performance standard, an expectation in the amount of CO_2 that these facilities can emit. We don't specify a particular technology. That is one of the beauties of how the Clean Air Act has worked over the years is that it provides room for innovation and flexibility and smart people, like you heard from the previous panel, finding better and less costly ways to do things.

But when it comes to the technology that we based those numbers on, we believe that if you look across all the information and data that is available, that there is adequate and robust data showing that the various components that we base that standard on are in use, have been in use, and will be ready——

Chairman SCHWEIKERT. But even in many of your own documents, and, look, this is just sort of an academic discussion I am trying to—there is discussions of demonstration projects but none of them are near the types of scales we are talking about with also the geographic, geological diversity. It is a little trucky—excuse me—it is a little tricky writing a rule set to something that is still I think a long way from scaled demonstration. And so from a personal concern, as we heard in testimony and then it was actually corrected by a couple of the other folks, almost all other clean air technologies that have been adopted had actually been around for years in some type of full scale before it actually hit clean air rule sets.

Can I just walk through one other—and this is one I am genuinely trying to get a better—wrap my head around is we keep having the discussions that EOR may be one of the financing mechanisms of, you know, ACO_2 types of capture. But at the same time as we look at some of the discussions, what is it, RR? I will just refer to it as number six well regs. Doesn't this discussion over here dramatically change the economics of EOR and even just the discussion of it creates sort of a potential cost liability that even if you are going to say, hey, we are willing to sort of enter into these future agreements for an EOR capture mechanism, but all of a sudden if we end up in this new regulatory environment, we have just destroyed the economics of such type of agreement.

Ms. McCabe. Well, there was a lot in your question, Mr. Chairman, so I will try to—I will go——

Chairman Schweikert. And sorry about that. It was a linear line of thought.

Ms. McCabe. Yeah. No, I understand. Let me talk about the last part of your question first. The people are doing EOR. People have been doing EOR——

Chairman Schweikert. For decades.

Ms. McCabe. —for decades very successfully. And though—the regulations that people have been speaking about, the RR regulations had actually been around for a number of years as well and——

Chairman Schweikert. But like number six——

Ms. McCabe. —people have been using them——

Chairman Schweikert. But has there ever been an—and I am sorry; I know I just interrupted and I hate it when I do that—an EOR which actually—where there is a number six sort of well standard?

Ms. McCabe. Well——

Chairman Schweikert. Because something like that doesn't exist anywhere.

Ms. McCabe. The number six well standard is for situations where people are injecting CO_2 into the ground solely for the purposes of sequestering it there and leaving it there.

Chairman Schweikert. Okay.

Ms. McCabe. EOR is a completely different application.

Chairman Schweikert. So EOR would fall more under the RR?

Ms. McCabe. So that is the Class II well——

Chairman Schweikert. Okay.

Ms. McCabe. —EOR.

Chairman Schweikert. So if I was doing EOR, I would be able to stay—you are telling me stay within Class II well standard and the RR enhanced regs side would not affect me?

Ms. McCabe. No, the RR regulation—monitoring regulations do apply when an intent is to leave CO_2 in the ground and it is intended to provide that additional information and assurance that the CO_2 actually is remaining in the ground.

Chairman Schweikert. So if I did EOR but part of it was also as a capture mechanism, I would still at least—I would fall under the——

Ms. McCabe. That is right.

Chairman Schweikert. —future monitoring?

Ms. McCabe. That is right.

Chairman Schweikert. Okay. Thank you.

And with that, just because I know I am over time and you have some time restraints on you, hopefully we will get a second round.

Ms. Bonamici.

Ms. Bonamici. Thank you very much, Mr. Chairman. Thank you, Ms. McCabe, for your testimony.

When you listened to the prior panel—and I have to say that there seems to be some mixing of the standards of adequately demonstrated and commercially available. I went back and looked at some of the discussion when Section 111 was implemented—when it was passed and implemented, and I found a discussion from the Senate Committee that says that it was designed to promote constant improvement in techniques for preventing and controlling emissions from stationary sources, and an emerging technology used as the basis for standards of performance need not be in actual routine use somewhere.

And also a D.C. Circuit Court interpreted "adequately demonstrated" to be "technically feasible" stating that the section looks toward what may fairly be projected for the regulated future rather than the state-of-the-art at present since it is addressed to standards for new plants. So could you talk just a little bit about how this section has spurred technology development previously? And we heard some testimony before about if the regulation is there, that the technology is developed, but without that requirement, the technology is not. So if you could address that and then I have another question.

Ms. MCCABE. Sure. You are exactly right, and the history and the description that you have given of Section 111 is exactly what we understand the Clean Air Act and Congress to have intended, which is that technology will move and innovate when there is a requirement to do so. We heard a lot of discussion about that today.

But there are many examples going back through time where Section 111 was the mechanism that took emerging technologies and brought them into the mainstream. And in fact, there is—Mr. Chairman, I do have to take issue with your comment a minute ago that in all prior 111 rules technology had been around for years. That is really not the case. One example I can cite for you is selected catalytic reduction technology, which is a NOx reduction technology, and it had been used in one type of application but it had never been used for industrial boilers.

Chairman SCHWEIKERT. To that point, actually, the catalytic converter——

Ms. BONAMICI. It is my time, Mr. Chairman.

Chairman SCHWEIKERT. I won't take it out of your time.

That catalytic conversion technology had been around a century, you know, using—you know, in the high temperature adjustments, maybe not in the way you described it, but it had been around for quite a long time.

Ms. MCCABE. It had not been used in this particular—and the particular sector——

Chairman SCHWEIKERT. But the basic technology has been around for decades and decades.

Ms. MCCABE. And similarly here we have technology that has been around for decades and decades and used in a variety of applications. So you do find that Section 111—and when these requirements are put in place, it does drive that technology development and then it becomes more widespread, the costs go down, and it becomes part of the mainstream.

Ms. BONAMICI. I wanted to ask you also—thank you for your testimony—that you mentioned in your testimony that the EPA plans to issue proposed guidelines to lower carbon pollution from existing power plants by June of this year and that the Agency recognizes that existing power plants require a distinct approach. In fact, the EPA's website states that the standards that will be developed for currently operating sources are expected to be different from and less stringent than the standards proposed today for future sources. Can you please discuss EPA's process for developing guidelines for existing power plants and why the guidelines will be less stringent and more flexible than the standards for new plants?

Ms. MCCABE. Absolutely. We are operating under two distinct elements of the Clean Air Act here, and the Clean Air Act traditionally has had a very different approach to regulating existing sources. In fact, for the most part, existing sources are regulated under state plans, and that is exactly what will happen here.

So EPA's job here is to set guidelines for how the states will go about developing plans to address their own power plants. And the expectations for what would be appropriate technology for existing plants that are in place, that are located where they are, that have whatever remaining life they have are very, very different.

And, for example, and the Administrator has said this on numerous occasions, we do not have any expectation that carbon capture and sequestration would form the basis for any expectation relative to existing plants.

Ms. BONAMICI. Thank you. And one more question. There has been some discussion today about the potential increase in costs if the carbon capture and storage rule is—when it is implemented. Can you talk about some of the costs associated with the lack of action to address climate change and increasing emissions? Thank you.

Ms. MCCABE. Yes. It is a very good question. There are costs to our economy and to society from the impacts that climate change are already having. In 2013 there were seven extreme weather events, which I think is kind of a nice way of saying great big huge horrible storms, that cost the economy over $1 billion each. And this is a real economic impact on our communities, on our families across the country.

Ms. BONAMICI. And healthcare costs might be——

Ms. MCCABE. And healthcare costs and disruption to families and to all communities.

Ms. BONAMICI. Thank you. My time is expired. I yield back.

Thank you, Mr. Chairman.

Chairman SCHWEIKERT. Thank you, Ms. Bonamici.

Chairwoman Lummis.

Mrs. LUMMIS. Thank you for being here, Ms. McCabe.

Are you here to testify then that these weather events absolutely were caused by climate change?

Ms. MCCABE. There—the scientific community has identified a number of impacts of climate change. Among those are increased intensity and frequency of weather events——

Mrs. LUMMIS. So are you sure that these specific weather events that you cite are caused by climate change?

Ms. McCabe. I can't—I am not a meteorologist. I can't speak to any specific weather event and——

Mrs. Lummis. Thank you. Why is the EPA requiring a CCS analysis for new natural gas-fired units, including power plants, as well as boilers and heaters within manufacturing plants?

Ms. McCabe. The EPA is proposing a performance standard for new fossil-fired power plants. We have one standard for gas and one standard for coal. Those standards are based on our review of the data that is available about what technologies are available for those plants to use going forward and——

Mrs. Lummis. Can you outline for us today the specific condition under which EPA would require CCS for either natural gas-fired utility units or non-utility boilers and heaters?

Ms. McCabe. The rule does not require any specific technology. The rule sets a performance standard.

Mrs. Lummis. Well, why is the agency requiring this analysis?

Ms. McCabe. We are not requiring anybody to do an analysis. We are setting a performance standard that new plants will need to meet——

Mrs. Lummis. Does CCS need guidance? Is that the same thing? Are we speaking about the same thing?

Ms. McCabe. Perhaps we aren't. I thought you were talking about the proposed New Source Performance Standards rule. Is that not correct?

Mrs. Lummis. That is correct.

Ms. McCabe. Okay. The New Source Performance Standards rule, which we proposed last fall and is in the comment period now, addresses new, not-yet-built, not-yet-started coal and gas-fired power plants, and that rule sets a performance standard that the companies then will figure out how they will meet.

Mrs. Lummis. Wouldn't an EPA policy memorandum stating that CCS is not required for new natural gas plants reduce this regulatory uncertainty and help expedite permitting decisions?

Ms. McCabe. For natural gas plants? The——

Mrs. Lummis. This is for EPA—you are requiring CCS analysis for LNG facilities, too, correct?

Ms. McCabe. Congresswoman, I think you may be talking about the Prevention of Significant Deterioration program.

Mrs. Lummis. Yes.

Ms. McCabe. Okay. So that is a program that when new plants come in, require them to go through an analysis of what the best technologies are out there and then employ that as part of their project. And so that is what I think we are talking about here.

Mrs. Lummis. The distinction between EPA's analysis of best system for emission reduction for coal versus natural gas escapes me. Are there any pulverized coal projects you can cite like post-combustion CCS?

Ms. McCabe. So there are several plants that have been using carbon capture—power plants that have been using carbon capture, for example, the Shady Point plant, the Warrior Run plant. There are also several plants that have been discussed today that are in construction that will be using this technology.

Mrs. Lummis. Are there any post-combustion natural gas projects?

Ms. McCABE. Using CCS?

Mrs. LUMMIS. Yes.

Ms. McCABE. Not that I am aware of.

Mrs. LUMMIS. What about pre-combustion CCS projects on coal plants?

Ms. McCABE. You are getting a little bit beyond my level of expertise, Congresswoman, but we would be glad to answer those questions for you after the hearing.

Mrs. LUMMIS. Okay. Thank you.

The President's budget includes 25 million to fund natural gas CCS projects. Now, if one of these projects becomes operational, would that be sufficient for EPA to begin requiring CCS as part of the NSPS or the PSD permitting process?

Ms. McCABE. I think it would—those are very fact-specific determinations and we would have to take a look at the particular facts when and if that happened.

Mrs. LUMMIS. My time is expired. Thank you, Ms. McCabe.

I yield back.

Chairman SCHWEIKERT. Thank you, Mrs. Lummis.

Mr. Hall.

Mr. HALL. Thank you, Mr. Chairman.

Ms. McCabe, I feel a little guilty and that I have been here a long time and I was here when we passed the Clean Air Act and Clean Water Act, and knowing the oil and gas people, I felt, and most of us Republicans and Democrats alike felt that they needed some oversight and—but they also needed some federal help. And I do not find that they have been conducive to fairness now in ordering a lot of companies to do things—to do the impossible and not give them time even to do the possible. And that is the major problem that I have seen, but I know that you are Acting Assistant Administrator, so you have been there several years, have you?

Ms. McCABE. Yes, sir.

Mr. HALL. Okay. Well, then in the EPA's first New Source Performance Standard proposal in 2012 you were there. The EPA determined that carbon capture and storage technology was not the best system of emissions reduction for new coal power plants, correct? That is what it says. That is——

Ms. McCABE. Yeah. That is the proposal that we withdrew, Congressman.

Mr. HALL. Well, I am getting to that. A year later in your latest proposal EPA says it is now the best system for emissions reduction. You just changed your mind overnight?

Ms. McCABE. No, sir. We revised our proposal——

Mr. HALL. It took you a month or so to do it then?

Ms. McCABE. No, sir. We revised our proposal based on the information that we had available to us at those points in the process.

Mr. HALL. Okay.

Ms. McCABE. And we felt—and we got a lot of input on the first proposal and we felt that a different approach was the appropriate one given all of that information that we obtained.

Mr. HALL. What has changed so dramatically in one year to allow the EPA to reach a different conclusion on the technical and economic feasibility of CCS?

Ms. McCABE. We actually felt that the revised proposal provided a much clearer and more appropriate path for gas-fired facilities and coal-fired facilities, and that was the basis for our decision to change the proposal.

Mr. HALL. Well, I guess I was hoping that you could help me understand the EPA's position with respect to the Clean Air Act's requirement that it can only mandate the use of emissions reduction systems that have been "adequately demonstrated." Would you agree, yes or no, that there isn't a single utility scale power plant in the world currently operating with CCS?

Ms. McCABE. Not—I am sorry. Can you repeat the last part of that?

Mr. HALL. Would you agree that there isn't a single utility scale power plant in the world currently operating with CCS?

Ms. McCABE. There are small facilities operating.

Mr. HALL. There are small—what do you——

Ms. McCABE. There——

Mr. HALL. How do you distinguish that?

Ms. McCABE. Well, there are a variety of sizes of utility boilers and there are operating facilities that are small that are using this technology now.

Mr. HALL. Okay. Well, then would you agree, yes or no, that the law's requirement that a technology system be "adequately demonstrated" is past-tense, not future-tense? You are having a hard time with that one.

Ms. McCABE. Well——

Mr. HALL. Do you want me to go onto the next one?

Ms. McCABE. Well, no, sir. I would agree that the law requires that we look at technology that is in use and make a judgment based on whether that is feasible and available for the particular sector that the rule covers.

Mr. HALL. That it is adequately demonstrated?

Ms. McCABE. That it is adequately demonstrated.

Mr. HALL. The Clean Air Act requires that the entire system of a new technology be adequately demonstrated, not just the individual components. How does EPA's decision to mandate that power plants employ a technology system that has never been fully and adequately demonstrated considered legal under the Clean Air Act? How can you justify that?

Ms. McCABE. We believe that the system has been adequately demonstrated looking at the variety of applications that have been used and are in use and have been used for many years.

Mr. HALL. Well, maybe you can and this next—you can provide any other example of a "demonstrated" technology required by EPA regulations where the technology was not used on a commercial basis?

Ms. McCABE. The—our—the—our rule and the technical documents that accompany it go through all the examples of existing uses of the various technologies that we base of the rule on and we are happy to provide those to the——

Mr. HALL. Okay. Let me close. I just have two seconds left.

Ms. McCabe, at a hearing before the Energy and Commerce Committee on September 2011, Administrator McCarthy had this to say: "I certainly don't want to give the impression that EPA is in the business to create jobs," one of the most cruel statements I have ever heard. Do you agree with the Administrator's statement?

Ms. McCABE. I don't know—I am not familiar with that quotation. That is not how the Administrator feels. We are very concerned about——

Mr. HALL. It is just the way she talks——

Ms. McCABE. —jobs that are created——

Mr. HALL. —but not the way she feels?

Ms. McCABE. I wasn't there——

Mr. HALL. I know you weren't.

Ms. McCABE. —Congressman. She is very concerned about——

Mr. HALL. I don't believe you would have said——

Ms. McCABE. —jobs in this country.

Mr. HALL. —anything like that. I would like to think you wouldn't because I left her space to correct that or to apologize for it or to say she was misquoted.

I yield back. I don't have time. Thank you.

Chairman SCHWEIKERT. Thank you, Mr. Hall.

Mr. Hultgren.

Mr. HULTGREN. Thank you, Chairman.

Thank you, Ms. McCabe, for being here today. It really is crucial that we on the Science Committee have a thorough understanding of the science behind the technological development necessary for your agency to accomplish the goals the President has set out.

While Administrator McCarthy has come before this committee touting science as the backbone of everything you do at EPA, I am worried that this has not been the case in regards to the technologies your agency is essentially mandating with your proposed regulations.

When designing the rule for the New Source Performance Standards, I assume EPA was in close consultation with the National Energy Technology Laboratory when deciding whether or not technology was adequately demonstrated. Was that the case?

Ms. McCABE. Well, we do work closely with them but it is EPA's job to make the determination about whether technology is adequately demonstrated. That is my——

Mr. HULTGREN. So there—and that specifically adequately demonstrated but there was not cooperation or consultation with the National Energy Technology Laboratory?

Ms. McCABE. There was consultation and much discussion with them about the types of technologies that are out there and various scientific and technical discussions about them, but the determination within the law is EPA's to make.

Mr. HULTGREN. As of December 2012 NETL report on the Technology Readiness Assessment for clean coal research programs, NETL had 285 projects underway developing technologies related to CCS. Only one project had a TRL above 6 and 77 percent of the projects were at 4 or below. The only project above 6 was a regional carbon sequestration project that is not widely applicable across the United States.

The DOE fossil energy description of plant technology as TRL 6 is engineering scale models or prototypes are tested in a relevant environment. Pilot or process development unit scale is defined as being between 0 and five percent final scale. I wondered how did

EPA reconcile the obvious differences between what you are calling adequately demonstrated and what the administrative agency charged with developing the technology has clearly defined as being at five percent or less of the final scale?

Ms. MCCABE. Well, there is a lot of information available about the types of technologies that we are talking about here, and in fact, the Secretary of Energy has indicated on many occasions that he is comfortable that this technology is available and ready for use and should be employed.

So these are all the kinds of discussions that we have with technical experts in and outside of government to make a determination about adequately demonstrated.

Mr. HULTGREN. Well, the frustration for us is there is a clear differentiation and it seems like ignoring many of those who should be listened to.

One of the reports that helped spur DOE to begin assessing technology readiness came from GAO, the title, "Major Construction Projects Need a Consistent Approach for Assessing Technology Readiness to Help Avoid Cost Increases and Delay." While this report focused on the cost overruns and delays for DOE projects but did not assess whether or not a technology was ready before construction began, it only makes sense that the private sector would experience the same problems developing and integrating the vast amount of unready systems necessary for a commercially viable plant to begin operating.

My concern is that we are rushing this out before it is ready at the detriment of long-term technological advancements and cost decreases. What evidence does EPA have showing the private sector is better dealing with these cost increases and delays when developing and integrating unready technologies?

Ms. MCCABE. Well, Congressman, I think you are reflecting the history of the way technology has in fact developed under the Clean Air Act. And as we heard earlier, there are projects moving forward today where private sector commercial operations are competing essentially to provide this technology to projects going forward. So we are seeing it in the marketplace and this is the way technology develops. It is the way it developed with scrubbers; it is the way it developed with SCRs and many other examples of technology. It starts with a few projects and then it grows.

Mr. HULTGREN. For me it is a privilege to serve on the Science, Space, and Technology Committee. As I started questioning, talked about again how we have heard over and over again that science is the backbone of everything you do at EPA. Again, just from the few questions I have had and from what I have heard today, I think there are real concerns of that is not the case, that there are other agendas pushing ahead of what the science says. We are concerned about that. I want to get back to truly seeing science as the backbone of everything EPA does.

With that, Mr. Chairman, I yield back.

Chairman SCHWEIKERT. Thank you, Mr. Hultgren.

Mr. Rohrabacher.

Mr. ROHRABACHER. Thank you very much.

Mr. Chairman, yes, it is important that we get our science right here because what we are doing is mandating costs and mandating, how do you say, goals that our business has to achieve in order to provide services and products and jobs for our people.

Let me just note that for the record, Mr. Chairman, I would like to put in for the record an article by Professor Matt Collins of the United Kingdom's Meteorological Office, a professor at Exeter University, suggesting that his analysis that there is no evidence to suggest that weather is any more ferocious or frequent than it ever has been in the past. I would like to put that into the record at this point.

Chairman SCHWEIKERT. Without objection.

[The information appears in Appendix II]

Mr. ROHRABACHER. So we see and we also heard earlier about 97 percent of the scientists that quoted again and of course, as I suggested during the last time I had a chance to ask questions, that was 97 percent being presented to us as 97 percent of all the scientists is actually 97 percent of the scientists who replied to a questionnaire in which the people who were asked were actually decided upon and then it was just the people who replied to the questionnaire, much less 97 percent of all scientists.

You don't believe that 97 percent of all scientists agree with the manmade global warming theory, do you?

Ms. MCCABE. Congressman, there is overwhelming support in the scientific community——

Mr. ROHRABACHER. That is not my question. The 97 percent that we hear, overwhelming could be 60 percent, could be 50 percent. I don't even believe it is overwhelming, but you don't believe it is 97 percent, do you?

Ms. MCCABE. I don't know that it is helpful to talk about——

Mr. ROHRABACHER. Well, I am asking you a question.

Ms. MCCABE. Right.

Mr. ROHRABACHER. Do you believe that this is clear—this 97 percent figure is thrown at us all the time. You don't believe that, do you?

Ms. MCCABE. I don't believe it or disbelieve it, Congressman.

Mr. ROHRABACHER. You don't want to answer the question, do you?

Ms. MCCABE. No, it is just—it is not a——

Mr. ROHRABACHER. Why can't you answer the question then? I am asking you whether you believe that this figure that is presented to us as the 97 percent an accurate or inaccurate figure?

Ms. MCCABE. Ninety-seven percent of the studies on this issue conclude that climate change is real and happening.

Mr. ROHRABACHER. That wasn't my question. My question was do you believe that 97 percent of the scientists believe that global climate change is happening because of human activity?

Ms. MCCABE. Well, the premise of your question, the 97 percent——

Mr. ROHRABACHER. Okay.

Ms. MCCABE. —doesn't come from——

Mr. ROHRABACHER. Okay.

Ms. MCCABE. —number of individual scientists; it comes from the number of studies.

Mr. ROHRABACHER. Okay. So in other words, the people who have been throwing the 97 percent figure at us have been wrong?

Ms. McCABE. I don't know who has been saying what——

Mr. ROHRABACHER. Well, we just heard it earlier, didn't we, in this—so you weren't listening to the——

Ms. McCABE. I was——

Mr. ROHRABACHER. All right. All right.

Ms. McCABE. —listening.

Mr. ROHRABACHER. Okay. You don't want to answer that question. I got it.

Well, and you believe then that the weather is more ferocious. I just put a very reputable scientist who obviously doesn't agree with you. He is probably not apart of that 97 percent of that you don't want to comment on. Do you believe that the weather now is more ferocious and do you disagree with that scientist's findings?

Ms. McCABE. I am not familiar with that particular study so I don't want to speak to it in particular. I am also not a climate scientist myself——

Mr. ROHRABACHER. All right.

Ms. McCABE. —so I don't want to hold myself out as an expert on that, but I pay attention to——

Mr. ROHRABACHER. Okay. Now, with that said, if all of the mandates that we are talking about and the change in regulation that we are talking about happen, I take it is—and we keep hearing that it is motivated on trying to save the climate and this—change the climate of the planet to make sure that we aren't changing the climate of the planet, how much effect on the climate of the planet will these regulations have?

Ms. McCABE. So these regulations are intended to control the amount of CO_2 that is emitted——

Mr. ROHRABACHER. Right.

Ms. McCABE. —by future power plants. We know that CO_2——

Mr. ROHRABACHER. Um-hum.

Ms. McCABE. —is a key contributor to what is happening in the climate and that we must reduce the amount of CO_2 in the atmosphere in order to have an impact.

Mr. ROHRABACHER. Um-hum.

Ms. McCABE. This is a global pollutant.

Mr. ROHRABACHER. Right.

Ms. McCABE. It is a global problem.

Mr. ROHRABACHER. Right.

Ms. McCABE. There are many, many sources of it. These are significant sources of it and——

Mr. ROHRABACHER. So there will be a significant change in our climate if we follow these new guidelines, is that correct?

Ms. McCABE. These guidelines are an important part of an effort in this country and globally to make the kind of changes that are needed to address climate change.

Mr. ROHRABACHER. Okay.

Ms. McCABE. You will not be able to——

Mr. ROHRABACHER. That is a good way not to answer the question. How much effect will it have on the climate?

Ms. McCABE. You will—no individual rule will be able to be traced——

Mr. ROHRABACHER. Very little——

Ms. McCABE. —because this is——

Mr. ROHRABACHER. So it will have very little impact——

Ms. MCCABE. It is——

Mr. ROHRABACHER. —is that right——

Ms. MCCABE. It is an——

Mr. ROHRABACHER. —if any?

Ms. MCCABE. It is an important aspect of the effort to reduce CO_2 globally.

Mr. ROHRABACHER. All right. Again, you don't want to answer the question.

Listen, when I ask a question in a debate, I am willing to debate the things that I disagree with. You have dodged almost every question that I have asked you. I am sorry. That is not the way we should be handling ourselves here.

But with that said, I think there is an honest disagreement as to whether human activity is changing our climate. It is an honest disagreement. We need to be more forthright and willing to actually confront the points being made by each side of this debate, and I don't think you have been that way with us today.

Thank you very much.

Chairman SCHWEIKERT. Mr. Cramer.

Mr. CRAMER. Thank you, Mr. Chairman. Thank you, Ms. McCabe, for your testimony, for being with us during this long morning into the afternoon.

There was some confusion I sensed when Chairman Hall asked about current use or current demonstrations of CCS. How many coal plants use carbon capture now, coal-fired electricity plants?

Ms. MCCABE. So I actually don't add these up. Do we have a number?

Mr. CRAMER. Can you name some? Could you name some?

Ms. MCCABE. Yeah. Yeah. So the Warrior Run power plant, the Shady Point power plant, there is a power plant in Germany called to the Vattenfall Schwarze power plant.

Mr. CRAMER. Do you know what the average size or how many megawatts they produce?

Ms. MCCABE. I don't have that information with me, Congressman, but we can get it for you.

Mr. CRAMER. Okay. Because I have to be honest. Now, I am going to respect the Ranking Member who has very effectively tried to discern the difference between adequate demonstration and commercially available, and yet without something being commercially available, I don't know how you demonstrate it. In other words, if it is not being done at a commercial level, at a level that would be equivalent to what we are asking here and what we are suggesting in terms of new power plants, it is hard for me to comprehend how it has been adequately demonstrated. But I respect the difference.

How are we going to determine whether something is adequately demonstrated if it is not commercially deployed at the scales that we are applying the rule to?

Ms. MCCABE. Right. Well, I think that is the debate that is concerning the Committee here. The Clean Air Act does not use the term "commercially available." It uses the term "adequately demonstrated." And as Congresswoman Bonamici cited some of the history of that section and the way it has been applied, it has been—it was clear that Congress intended for this provision to be—to put the United States on the forefront of developing technologies. And so it is not an expectation that technology be wide—in widespread use, and that has been clearly demonstrated over the years.

Mr. CRAMER. But in the most recent proposal, you actually do state that carbon dioxide emissions from new power plants are from CCS has not been implemented and that we believe there is insufficient information to make a determination, these are quotes from the EPA's proposed rules regarding technical feasibility. It seems to me that the same exact thing applies here to coal, that if it has not been done with CCS, or with combined cycle, it has not been done with coal, why the difference?

Ms. MCCABE. Well, there is a difference. There is a difference in the information that is available and there is a significant difference in the ways in which these technologies are deployed and are being used in the coal versus natural gas situations. There are also technical differences between the operations of those plants where we do not have information on the natural gas side that we do on the coal side, and that is the basis of our proposal.

Mr. CRAMER. As you know, in order for this, if we had the carbon capture technology and if it was adequately demonstrated and it became commercially available and it was economically feasible to do it, and to meet the growing demand—by the way, in North Dakota where I live and where I was once a regulator, we have a demand of over 2,000 megawatts right now that is being unmet to meet the growing economy that we have as a result of our more reasonable regulatory touch I might add.

But the EPA has specifically cited the North Dakota Weyburn CO_2 pipeline from the——

Ms. MCCABE. Um-hum.

Mr. CRAMER. —great Synfuels plant——

Ms. MCCABE. Yeah.

Mr. CRAMER. —Great Plains Synfuels plant, which I was just at a week ago Friday with the Administrator.

Ms. MCCABE. Yeah.

Mr. CRAMER. We had a very good meeting there. But that requires an international pipeline. You perhaps heard me discuss it earlier today. This is day 2,000 of the Keystone XL pipeline's review process, which the EPA has largely criticized and opposed, continues to throw up sort of barriers I guess. Is EPA prepared to, you know, support CO_2 pipelines all over the country and perhaps even across international lines?

Ms. MCCABE. There are CO_2 pipelines across the country and we are——

Mr. CRAMER. I am very familiar with that——

Ms. MCCABE. Yeah. Yeah.

Mr. CRAMER. Yeah.

Ms. MCCABE. And we believe that that is an important part of moving this technology forward and putting in place things that will be able to take carbon dioxide out of the air.

Mr. CRAMER. I just hope the EPA is this cooperative when it actually comes time to siting some of these CO_2 pipelines should we need to get them to market.

I am just going to wrap up, Mr. Chairman, by saying that the EPA also notes that natural gas prices—and they have claimed natural gas prices have been the real determining factor in the marketplace, and yet we are—here we are coming off of the winter where PJM actually had to seek relief from FERC from its $1,000 per megawatt hour price cap because natural gas prices spiked as a result of a cold winter. It is a very volatile fuel. I support it but I don't think we should displace coal with it.

Mr. BRIDENSTINE. [Presiding] The gentleman yields back.

Mr. Weber from Texas.

Mr. WEBER. Thank you, Mr. Chairman.

Ms. McCabe, should the President issue a red line on CO_2 emissions? Would that help?

Ms. MCCABE. I am not sure I understand your question.

Mr. WEBER. Well, when he declares that there is a red line—or would that further erode the Administration's capability in a, pardon the pun, storm of controversy? It seems like the global warming religion has been bought into hook, line, and sinker by this Administration. You talked about the Administration's credibility and EPA's credibility. Are you aware of the three fracking cases where they issued a statement to the fact that they had contaminated water in three areas of the country here, a year or two back? Are you familiar with those three cases?

Ms. MCCABE. I am not sure I know specifically what you are referring to.

Mr. WEBER. Okay. But you are aware that it did happen?

Ms. MCCABE. I am aware that there have been issues related to——

Mr. WEBER. Right, and they had to retract their statement that in fact fracking had contaminated three areas of drinking water?

Ms. MCCABE. I am actually not familiar with the specific statements that you are——

Mr. WEBER. Well, I am glad——

Ms. MCCABE. —referring to.

Mr. WEBER. —I can inform you of that today. That makes me feel like today was in some fashion worthwhile.

You mentioned in your prepared remarks, I have got a copy of it here in front of me, that EPA would like to be able to approach on—I am sorry—that you would be able to capitalize on state innovation in dealing with these regulations. And if you look up the word capitalize, there are a couple different definitions. It says take advantage of, turn something to one's advantage, and then the other one is supply with capital, as in dollars and cents. And you were, I think, in the backroom watching the previous panel, is that right?

Ms. MCCABE. Yes.

Mr. WEBER. I don't know if you saw my comments about the carbon capture and sequestration and storage facility in my district in Port Author by Air Products where it was a 400 and something million dollar project, but the EPA—or the DOE rather supplied 66 percent of the funding. You are aware of that project?

Ms. MCCABE. I am aware of the project and I heard your statements earlier.

Mr. WEBER. Okay. And you don't disagree with what I said in that regard?

Ms. MCCABE. I don't have independent knowledge of the amount.

Mr. WEBER. Okay.

Ms. MCCABE. I will take your word for it.

Mr. WEBER. But it sounds reasonable. So in Texas we have been doing enhanced oil recovery for about 40 years, as was alluded to by our colleague on the left, Marc Veasey, earlier. And we do a good job of it. And so you want—in your earlier comments, you said you wanted to capitalize on the stakeholder input and the states', I guess, experience. Texas has a great, great history of experience in EOR and in producing an economy that is arguably the 11th largest in the world if it was a country. Why wouldn't you want to follow Texas' model when it comes to enhanced oil recovery, when it comes to air quality permitting? I realize that is—we are in a little bit different realm there——

Ms. MCCABE. Um-hum.

Mr. WEBER. —but why won't the EPA acquiesce to following the TCEQ in Texas? Do you have any knowledge about that?

Ms. MCCABE. Well, our job under the Clean Air Act when it comes to setting standards for new——

Mr. WEBER. Um-hum.

Ms. MCCABE. —power plants is to do that, is to set standards for new power plants. What I was referring to in my testimony was the provisions dealing with existing power plants where we do very much intend to look to states that have been——

Mr. WEBER. Thirteen hundred people a day are moving to Texas. We have created more jobs than the other lesser 49 states in many years combined——

Ms. MCCABE. Um-hum.

Mr. WEBER. —and we are the country's leading state exporter of products for like 11 years running. We get it in Texas. Less onerous government regulations, we have got wide-open spaces with clean air and great drinking water, and so I hope that the EPA will really take that into account and follow Texas' model on that.

Are you here today to testify that you think that what was done at the Air Products plant in Port Arthur, Texas, a $400 million project with 66 percent government funding, that that proves and demonstrates that this is a viable project to be done or a process in business? Are you here to testify to that?

Ms. MCCABE. Sir, I am here to speak about our proposal, which is based on a variety of information, not any——

Mr. WEBER. And do you think that that is——

Ms. MCCABE. —one single project.

Mr. WEBER. But—all right. Well, can you tell me of another carbon capture and sequestration storage facility that is that big or of that magnitude?

Ms. MCCABE. Well, there is—I am not as familiar with the specifics of that project as you are certainly, but there are places where carbon is being injected into the ground. There is lots and lots of EOR going on everywhere around the country and indeed around the world——

Mr. WEBER. So you don't have an opinion about whether that adequately demonstrates this as a duplicable process?

Ms. MCCABE. I do have an opinion that we set forth in our proposed rule that when you look at all of this information that is available, all the projects that are out there, that we do believe that the technology has been adequately demonstrated to support the performance standard——

Mr. WEBER. Well, would you——

Ms. MCCABE. —that was proposed.

Mr. WEBER. —agree with the fact that the technology to put a man on the moon has been adequately demonstrated?

Ms. MCCABE. Adequately demonstrated is a legal term within the meaning of the Clean Air Act——

Mr. WEBER. Well, let me——

Ms. MCCABE. —and I wouldn't want to apply it——

Mr. WEBER. —put it this way. Did we put a man on the moon?

Ms. MCCABE. We did.

Mr. WEBER. Okay. But you would not want to mandate that all airlines need to have that technology, putting a man on the moon, right?

Ms. MCCABE. With respect, Congressman, I am not sure it is a valid analogy——

Mr. WEBER. Well, what I am saying is you are taking this plan based on the funding and the model that was done in the Air Products plant and you are saying that that adequately demonstrates that it ought to be in the rules.

Ms. MCCABE. I am saying that the whole body of information that we have is—supports a finding that the technology has been adequately demonstrated——

Mr. WEBER. And the EPA never takes funding into account, do they, the cost?

Ms. MCCABE. We do take cost into account, very much we do. And as our documents show underlying the rule, the cost—should I finish?

Chairman SCHWEIKERT. Please finish——

Ms. MCCABE. Okay.

Chairman SCHWEIKERT. —your thought.

Ms. MCCABE. The cost of building a new coal plant with all the technology that we have looked at, partial capture and sequestration is comparable with other non-natural gas-powered——

Mr. WEBER. Well, we are going to have to disagree.

Thank you, Mr. Chairman.

Chairman SCHWEIKERT. Thank you, Mr. Weber.

And Arizona is getting about 350 people a day, but we are a lot smaller.

Mr. Bridenstine.

Mr. BRIDENSTINE. Thank you, Mr. Chairman.

I had a couple of thoughts and questions. Over the past several months, we have seen a troubling trend of the EPA deliberately avoiding transparency and accountability. When members of EPA's own Science Advisory Board raised serious questions about the NSPS rule, astonishingly, the Agency claimed that storage is beyond the scope of this rule. In other words, the EPA wants people to believe that carbon capture and storage systems don't have to consider where the carbon goes and neither does the Agency. It is misleading and dangerous for the EPA to quietly dismiss inconvenient facts. Do you agree?

Ms. MCCABE. We—I have to disagree with the premise of your question, Congressman. We very much respect the role of the SAB.

We engaged with them in a very open process. All the conversations we had with them were completely open to the public and on the record.

Mr. BRIDENSTINE. Okay. I would like to submit this letter for the record. This is a letter from the EPA's Science Advisory Board. I will just read one sentence here, actually, a couple sentences. It says, "the portion of the rulemaking addressing coal-fired power plants focuses on carbon capture and that the regulatory mechanisms for addressing potential risks associated with carbon sequestration"—carbon capture—"are not within the scope of the Clean Air Act." And this is the advisory board.

"Carbon sequestration, however, is a complex process, particularly at the scale required under this rulemaking, which may have unintended multimedia consequences. The Board's strong view"—the Board's strong view—"is that a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in import systematic ways to this rulemaking." This letter has been submitted in the record.

Even though the EPA officials sought to, you know, obviously not take this into account, the EPA science advisors continue boldly to call for a thorough review of the science in the science underlying this rule. Will you commit to me today that you will heed your own science advisors and await a full review of the serious concerns raised by the Science Advisory Board before finalizing this rule?

Ms. MCCABE. We will of course work with our Science Advisory Board, but what I will reflect to you, Congressman, is what the Board recognized was that within the four corners of this proposed rule, the regulatory approach and the—the sequestration and storage is not within the four corners of this rule; it is addressed in other regulatory programs—

Mr. BRIDENSTINE. So real quick——

Ms. MCCABE. —that have been mentioned today.

Mr. BRIDENSTINE. —the law doesn't require the Agency to examine non-air environmental consequences of CCS systems?

Ms. MCCABE. That is a provision of the law.

Mr. BRIDENSTINE. Okay. But it is not a provision of what you deem appropriate in this rule?

Ms. MCCABE. No, not at all. Not at all. I was trying to clarify that the Science Advisory Board recognized that sequestration, underground injection of carbon, is addressed in other regulatory programs, not in this one.

Mr. BRIDENSTINE. Okay. Does the Agency consult with the U.S. Fish and Wildlife Service to determine if this rule would impact, endanger, or threaten species?

Ms. MCCABE. We have not consulted with the U.S. Fish and Wildlife on this provision.

Mr. BRIDENSTINE. Do you intend to?

Ms. MCCABE. We are—we will apply—we will comply with all applicable requirements, including that one if it is deemed to be applicable here.

Mr. BRIDENSTINE. So, again, will you commit to me that you will not go forward with this rule until you have, you know, examined the environmental consequences for non-air, you know, parts of the environment?

Ms. MCCABE. I will commit to you that before we finalize this rule, we will assure ourselves that we have satisfied all the legal requirements associated with this particular rulemaking.

Mr. BRIDENSTINE. Although I understand the proposal does not currently require carbon capture and storage for gas or oil power, can you assure me that the Agency will not consider requiring CCS for gas-fired power plants in the future?

Ms. MCCABE. We do not have a factual basis that suggests that that is an appropriate thing, which is why we did not include it in this rule.

Mr. BRIDENSTINE. Can you assure me that the Agency will not consider requiring CCS for gas-fired power plants in the future?

Ms. MCCABE. We do not have present plans to move in that direction.

Mr. BRIDENSTINE. Can you assure me that the Agency will not consider requiring CCS for gas-fired power plants in the future?

Ms. MCCABE. I can't commit the Agency indefinitely into the future, Congressman. I can tell you where we are right now and we do not foresee that.

Mr. BRIDENSTINE. One other thing that I think is important, you know, there is potentially the application of the new SPS standards or similar assumptions of reasoning to existing plants that are modified and reconstructed. Can you assure me that the Agency will not require CCS for modified and reconstructed coal-fired power plants?

Ms. MCCABE. That is a rule that will come out as a proposal later this spring, and that rule will lay out what the expectations are that are there. I will tell you that we are looking at those facilities which are existing in a different way than we look at brand-new un-built power plants.

Mr. BRIDENSTINE. You mentioned one project that is in Oklahoma, Sandy Point, as one of the projects that is a demonstration of the capability in the technology. How many of these projects are there?

Ms. MCCABE. I cited three.

Mr. BRIDENSTINE. Are they all power plants?

Ms. MCCABE. Those three are power plants. So the three I cited are power plants. There are many other industrial applications of the technology as well, but I was asked specifically about power plants.

Mr. BRIDENSTINE. And, for the record, can you submit what the current size and the status of those power plants are? My time is expired.

Ms. MCCABE. Sure. We will follow up with that information.

Chairman SCHWEIKERT. Thank you, Mr. Bridenstine.

You had requested a UC, there are only two of us so I guess there is no objection.

[The information appears in Appendix II]

Chairman SCHWEIKERT. It is always wrong when you object to your own Member. Yeah.

Give me just a couple seconds. I want to make sure that we touched on a couple other externalities that I wanted to make sure we had touched on.

I may submit a couple other more technical questions to you in writing.

Ms. MCCABE. Sure.

Chairman SCHWEIKERT. I know these are always sometimes mentally taxing and the preparation that goes into it.

This is the first time I have ever said this in my short time here in Congress. I am a little disappointed at some of the intellectual capital we have shared because I was somewhat hoping to do something much more technical on where are we really on the science. What is the, you know, I come from the world of the law of unintended consequences is when we don't think things through—how many major projects have we all stepped into, we have watched our government and industry step into and we are here a few years from now and we go, "we missed that."

You know, if we were holding this hearing 12 years ago, part of your opening would have been about peak oil and the world running out of energy and fossil fuels, and today, we know we had our data absolutely wrong. And how do we make major decisions like this that have a series of economic effects and hopefully environmental effects and make sure we are doing it in the most technically rational, thought-out, disciplined, and properly economically incentivized fashion? And so hopefully we can send you over some more questions and some of your team can respond to them.

And with that, I want to thank you for your testimony and do be prepared that the Members may have additional questions for you. And we will ask you to respond to those in writing. The record will remain open for a couple weeks for additional comments and written questions from Members.

And with that, thank you for participating with us today.

Ms. MCCABE. Thank you, Mr. Chairman. We will be happy to follow up——

Chairman SCHWEIKERT. And with that, the——

Ms. MCCABE. —with any questions.

Chairman SCHWEIKERT. And with that, the hearing is closed.

[Whereupon, at 1:01 p.m., the Subcommittees were adjourned.]

Appendix I

ANSWERS TO POST-HEARING QUESTIONS

ANSWERS TO POST-HEARING QUESTIONS

Responses by Mr. Robert Hilton

Response By Robert Hilton To Hearing Questions From the US House of Representatives Committee on Science, Space, and Technology

Subcommittee on Environment

Subcommittee Energy

Science of Capture and Storage: Understanding EPA's Carbon Rules

1. As an engineer, and representing a company that stands to profit through the sale of CCS technologies, do you believe CCS has been "adequately demonstrated" in full scale power plant applications and is Alstom offering standard commercial guarantees for this technology.

Answer: No, the technology has not been "adequately demonstrated" in full scale in power plants and Alstom is not offering standard commercial guarantees for this technology.

a. In your experience, will power providers invest in emissions control technologies that aren't backed by standard performance guarantees?

Answer: No, power providers expect performance guarantees including removal performance , power consumption, consumables consumption and other performance guarantees as well as larger guarantees like reliability, availability and other guarantees.

b. If an emissions technology does not perform "as advertised", what are the implications for the power provider? What are the implications for a company like Alstom?

Answer: Since the capture system will be part of the environmental permit, failure to preform would result in significant fines and the shutting down of the plant until remedies are executed. For a company like Alstom, we could, depending on the contract, be responsible for damages such as the cost of lost power production, value associated with failure to provide CO2 to an end user who had contracted for the CO2, if they exist, and other potential liquidated or consequential damages.

2. In the proposed rule, EPA claims that the use of CCS "components" at non-power plant industrial facilities proves that the full scale integrated CCS systems are adequately

demonstrated for commercial power plants. But in 2010 EPA co-drafted a report concluding that "the integration of CO2 capture, transportation, and permanent sequestration at commercial scale, coal-fired power generating facilities has not yet been demonstrated". Do you believe the literature supports EPA's position that the integration of CCS components has been demonstrated when the research sites appear to say the opposite?

Answer: No. The greatest risk in all chemical processes is the integration of the components at scale. Pilot plants and demonstrations can show that the processes work. However, integrating the components at full scale including tying the process to a real full scale power plant creates risk that cannot be anticipated or encountered at small scale or even in advanced modeling (since modeling effectively only knows what you have told it). Some examples would be: how does the CCS process react when the power plant suddenly comes down on load; how, when the CCS process depends on steam from the power plant, does the process react to lower steam availability and how quickly can the process adjust; what are the effects on the subsequent processes like compression and transportation of such events; what is the impact on the process when the upstream air pollution control equipment malfunctions.

3 .Setting EPA's proposed BSER determination aside, is there technological reason to assert that capturing and storing carbon from a coal fired power plant has been "adequately demonstrated" or is significantly different from the potential of capturing and storing carbon from a natural gas fired power plant? What are the estimated costs per megawatt generated?

Answer: As stated above, we do not believe that CCS on coal plants has been adequately demonstrated at full scale. There have been or are four small demonstrations of about 40 MW and many smaller plants. This is not adequate demonstration .As far as the technology being used on natural gas plants, the work at Mongstadt by TCM and Alstom has shown the same fundamental technology works on natural gas at similar scale. Alstom has published projected cost data based on a large number of assumptions and relying on these small scale demonstrations and concluded that given a reasonable variation range the costs for both fuels with CCS can be comparable on the cost of electricity.

4. EPA claims that the NSPS rule is technology forcing. In other words, by mandating technology, companies will find a way to make it work and use it. First, this seems to contradict the notion that the technology has been adequately demonstrated.

a. But setting that aside, what happens if you push CCS too hard and prematurely require its use? Does this rule really provide an incentive for CCS?

b. In your testimony, you say the Clean Air Act (CAA) is a "market driver" not a "technology driver". Can you explain the distinction you make- and the implications?

Answer: In the case of this regulation, by pushing CCS on coal alone, it means that the industry (as noted by EPA) will simply build gas plants. It should be noted that all effort behind CCS development has been supported by the coal interests. Even DOE's program only envisioned CCS on coal. Therefore if you stop building coal it is logical that the effort to develop CCS, funded by coal interests, will stop and the technology will not be developed as there will be no market for the technology in the foreseeable future. As proposed this regulation does incentivize CCS development.

The distinction I made between "market driver" and technology driver under the Clean Air Act is based on the history of technology being ready when EPA called for it not technology being invented when EPA called for it (as with carbon capture). The first sulfur commercial scrubbers were built in 1942 in London well ahead of the CAA. The first SCRs were developed in Japan in the 1980's well ahead of the NOxSIP Call in 1999. Mercury technology had been developed in the 1980s for Waste to Energy Plants at full scale well ahead of the mercury regulation in 2010. Particulate Control is similar. In all cases the technologies were decades ahead of CAA. Therefore I call the CAA a market driver. Only for Carbon on power plants was the technology never developed ahead of the regulation.

5. Mr. Hawkins testified that applying CCS will not raise the power prices because it averages over all plants. Do you agree with this assessment?

Answer: No. Generally in the US, plants dispatch based on their cost versus the price in the market. Therefore, plants with CCS will not dispatch until the price rises to their cost level or they may not dispatch at all. If they don't dispatch, obviously they won't raise the price. The first couple of plants will likely not influence the average price of electricity but once CCS is widely deployed and many plants have the higher cost that goes with the added cost of CCS, the price of electricity will rise sharply. DOE has indicated as much as 80%.

6. Mr. Hawkins said that the application of CCS will reduce carbon by comparing it to a new coal fired power plant without carbon capture and storage technologies. Do you agree that the rule would reduce carbon emissions or would you analyze reductions in a different way? Does EPA follow Mr. Hawkins' methodology?

Answer: Even EPA concedes that this rule will not reduce carbon since it only applies to new plants. This rule will simply slow the rate of accumulation because the new plants will be gas and produce carbon at a lesser rate. All agree no new coal will be built. In Mr. Hawkins analogy, you cannot claim reductions by referring to a base line of a new plant without CCS since that cannot be built.

7. What is the difference between the processes for IGCC and industrial gas separation (selexol and rectisol)? Are these the same as what would be required for most fossil power generation? Are these processes EPA and Mr. Hawkins cite, applicable to atmospheric flue gases? What are the respective technology limits and what has been demonstrated at scale today?

Answer: Selexol and Rectisol are processes designed to separate carbon at high pressure. It is what drives the reactions. Unfortunately, all power plants except IGCC operate at atmospheric pressure where these processes do not work. In simple R&D terms, more than a several dozen companies and DOE would not have pursued alternatives, spending billions of dollars, if these old known technologies worked on coal and gas power plants. Virtually no other technology has currently been demonstrated on a commercial scale power plant. While there are many small demos and pilots, currently there have only been 4 demos as large as 40 MW- clearly not full-scale. While many point to selexol and rectisol technologies on conventional gas separation, even DOE believed they needed to fund R&D efforts as the treated gas steams have different compositions and different impurities than conventionally treated streams.

8. EPA sites several examples of CCS technologies as being used for decades.

a. Would you discuss the details of any of the projects EPA has cited? What is the current status of each? Are these projects representative of full-scale power generation? Have they faced any challenges- either technical, financial, legal or otherwise?

b. Are polygeneration, industrial gasification or other similar projects that plan to integrate CCS substantially similar to CCS for Fossil fuel fired power plants?

c. Are there any failed proposals or abandoned projects that EPA has failed to cite?

Answer: The following were cited:

-Southern Kemper/Radcliffe: IGCC with selexol- full scale- start-up projected late 2014 or early 2015

-Sask Power Boundary Dam- 100Mw- not full scale - projected to start up in summer of 2014

-NRG Parrish- has not started construction

-Summit East Texas Clean Energy Project- has not started construction- polygen

-HECA - polygen- has not started construction

-AEP Mountaineer- 30 MW demo successful but shut down- commercial 250 MW project ended for lack of rate recovery or financing

-Southern Barry- 30 Mw demo- running

- AES Warrior Run and Shady Point- 12 MW and 7 MW respectively and extremely high power consumption (35% parasitic load) making these examples clearly not under consideration for commercial application.

All the polygeneration facilities are IGCC and use either selexol or rectisol. Each of these facilities are designed to produce chemicals as a prime source of revenue should they ever be built. So these would not be either technically or economically like a conventional power plants. Both of these facilities have had to seek financing outside the US but neither has closed financially.

9. I understand that there are some industries, such as the chemical industry and the cement industry that can utilize CO_2 in their production processes. I also understand that it can be used as a feed stock for algae and other alternative fuels.

It has been suggested using captured CO_2 in these types of applications may provide additional means of compliance for power plants. How would you characterize the feasibility of using these technologies to comply with EPA's NSPS proposal?

Answer: Many of these technologies offer promise, particularly low carbon fuels. However, virtually all of these offer niche markets compared to size of full scale deployment of CCS. It is hoped that as these processes are developed it can drive the R&D necessary to bring full scale carbon capture to the market at a cost reduction over current projection. It is worth noting that the cement industry in particular is a major CO2 generator and is looking to achieve reductions- thus not requiring more CO2. The final point is that many small scale R&D efforts are underway but none nearly at the scale require for the power plant industry.

Responses by Mr. Robert C. Trautz

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
Subcommittee on Environment
Subcommittee on Energy

Responses to Subcommittee Questions in Letter dated April 1, 2014
Relative to March 12, 2014 Hearing:

Science of Capture and Storage: Understanding EPA's Carbon Rules

Robert C. Trautz
Electric Power Research Institute

1. Can you discuss the operational differences between CO_2-based EOR operations and CO_2 storage operations that are not EOR-based projects? What are the technical challenges associated with geologic sequestration at the scale required under the NSPS proposal?

There are a number of significant operational differences between CO_2 EOR and CO_2 storage projects including 1) CO_2 purity and quality; 2) objectives and economics; 3) supply and demand; 4) legal and regulatory; 5) assurance of well integrity; 6) long-term CO_2 monitoring requirements; and 7) industry experience. A detailed analysis of these differences is described in the "Final Report by the Carbon Sequestration Leadership Forum Task Force on Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects" dated September 2013.[1] The most significant difference stems from the fact that the two types of projects have different objectives. EOR operators must purchase CO_2 and use it effectively to minimize costs and maximize profits from oil production. Therefore, EOR operators use CO_2 sparingly and recycle produced CO_2 whenever possible because it is a valuable commodity and large expense. EOR operators recognize that incidental storage of the CO_2 in the formation is unavoidable and an expense that must be factored into the initial financial investment decision. CO_2 storage operators on the other hand focus on storage capacity, long-term sustainable CO_2 injection and whether a low permeability caprock is present to keep the buoyant CO_2 in the storage formation. CO_2 storage operators must implement an extensive monitoring program to ensure that the CO_2 remains in the storage reservoir. In contrast, EOR operators perform limited monitoring to optimize flood performance and maximize oil production. Both types of projects must develop injection strategies, tailor injection operations and manage reservoir pressures to meet site-specific project objectives and investment needs.

The biggest challenge that CO_2 project developers face is the scarcity of available technical information on saline formations. Technology is available to collect the information, but given

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[1] Bachu, S., P.R. da Motta Pires, M. Li, F. Guzmán, L. Ingolf Eide, A. Aleidan, M. Ackiewicz, S. Melzer, Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects, Report Prepared for the Carbon Sequestration Leadership Forum (CSLF) Technical Group by the CSLF Task Force on Technical Challenges in the Transition from CO2-EOR to CCS, September 2013.

the large volumes involved with full scale CO_2 storage and scarcity of information, several attempts may be needed to find specific injection sites with suitable storage capacity and formation injectivity. Failed attempts to find suitable storage can result in higher asset exploration costs on the order of tens of millions of dollars for onshore and $50 million or more for offshore sites prior to injection.[2] Exploratory costs are especially high for heterogeneous rock formations that require more characterization.[3] These costs do not include the normal asset appraisal and development costs needed once exploration activities identify potential storage sites. The Gorgon Project, a natural gas separation and CO_2 injection project in northwestern Australia, has spent in excess of AU$150 million on site-appraisal activities for its CO_2 injection project prior to the financial investment decision. Gorgon is located within a known hydrocarbon province with good well control, but environmental costs associated with locating the project in a nature reserve have also contributed to increased costs. The onshore ZeroGen project in Australia represents the opposite end of the risk spectrum where AU$90 million was spent on site characterization activities for several years on a preferred saline target before the project was abandoned because the formation was found to be uneconomical for large scale storage.[4] From a technical standpoint, CO_2 storage operators will be faced with injecting large volumes of CO_2 into saline reservoirs over periods spanning several decades. Uncertainty associated with sustained injection of large volumes of CO_2 and associated pressure buildup in the storage reservoir that can lead to potential problems is borne out by existing global experiences documented in my written testimony for the Snøhvit and In Salah natural gas separation and CO_2 storage projects.

2. If we overcome the engineering challenges associated with storage, other practical problems persist. Issues such as long-term liability, mineral rights, pore space ownership, cross-state CO_2 plume migration, transport rights of way, and permitting authorities can dramatically overshadowed the technical challenges we hope to master with more projects.

Currently, the risks, unknowns, and uncertainties associated with CO_2 storage appear to be showstoppers.

a. What will diffuse the legal and practical complexities of CO_2 transport and Storage?

b. Is EPA moving in the right direction to solve these problems?

EPRI is aware of the legal issues that you have raised, which have been identified and analyzed by others in the CO_2 storage literature.[5, 6, 7, 8] As a technology and research & development

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[2] Global CCS Institute, 2011. The global status of CCS: 2010, Canberra.

[3] Zero Emissions Platform (ZEP), 2011. The Costs of CO_2 Storage: Post-demonstration CCS in the EU, prepared jointly by the European Technology Platform for Zero Emission Fossil Fuel Power Plants and the IEA-GHG programs.

[4] Garnett, A., 2010. "The ZeroGen Flagships Project Look back and Update," Presentation National CCS Week, Melbourne, Australia.

[5] Jacobs, W.B., L. Cohen, L. Kostakidis-Lianos, S. Rundell. "Proposed Roadmap For Overcoming Legal and Financial Obstacles to Carbon Capture and Sequestration" Discussion paper 2009-04, Cambridge, Mass.: Belfer Center for Science and International Affairs, March 2009.

[6] de Figueiredo, M.A., 2007. The Liability of Carbon Dioxide Storage, PhD dissertation, Massachusetts Institute of Technology

organization and a 503(c)(3) corporation, EPRI does not comment on legal feasibility or the appropriateness of direction taken by government agencies with respect to legal or policy related issues.

3. At a recent hearing Acting Assistant Secretary for Fossil Energy (FE), Chris Smith, stated that "FE is funding, in partnership with industry, eight major demonstration projects that will help address the first-of-a-kind technology risks that come with deploying innovative CCS technologies. He further noted that "FE is also focused on carbon storage, developing technologies with industry to ensure the safe and permanent storage of captured CO_2 in different geologic formations... These large volume tests and related applied science will provide the field experience to develop and validate technologies that can predict storage capacity, validate storage permanence, and develop best practices."

Is DOE really saying that these large volume tests have not been completed yet?

EPRI's experience is limited to direct involvement in the DOE Phase II and III Regional Carbon Sequestration Partnership (RCSP) program and American Electric Power's Mountaineer project under the DOE Clean Coal Power Initiative (CCPI). The Phase II projects consisted of injecting a few hundred to a few thousand tons or less of manufactured CO_2 shipped by transporter to each site. These small scale Phase II CO_2 storage projects have been completed. The CO_2 storage projects within the Phase III RCSP and CCPI programs are at various stages of completion but all are still ongoing. Injection of approximately 37,000 tons of CO_2 at the Mountaineer power station ended in May 2011, but post injection monitoring and site care continue as required by the State permitting authority. The individual RCSP projects aren't scheduled to be completed until 2017 with the exception of the SECARB Early Test near Natchez Mississippi. This includes the Plant Barry carbon capture and injection project where 100,616 metric tons of CO_2 has been injected to date. The SECARB Early Test is part of a 1.5 million ton per year commercial CO_2-enhanced oil recovery (EOR) project operated by Denbury Onshore, LLC that uses CO_2 derived from a natural source. This DOE research project is scheduled to be completed in 2015, but the commercial EOR operation will continue.

4. EPA's cost assessment of CCS is based, in part, on the assumption that power plants can sell CO_2 to EOR operators. In order to comply with the standard, however, storage operators must report under Subpart RR of EPA's greenhouse gas reporting rules.

a. Can you describe the effect this requirement will have on EOR operators? How is this different than Subpart UU requirements that EOR operators currently report under?

As stated in my testimony, the potential use of depleted oil and gas reservoirs for CO_2 storage could be adversely affected by potential regulatory requirements associated with CO_2 storage. Preliminary feedback from oil producers suggests that a requirement for EOR operators to

[7] Fish, J. R., S. Rives, E. L. Martin, California Carbon Capture and Storage Review Panel, Technical Advisory Committee Report: Approaches to Pore Space Rights, August 10, 2010.
[8] IOGCC, 2007. Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, The Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geologic Storage, supported by the Department of Energy under award number DEFC26-05NT42591, September 25, 2007.

monitor a storage facility and certify that the CO_2 is stored under Subpart RR of the EPA's mandatory greenhouse gas reporting program, could be a risk that companies may not be willing to accept. Thus, such requirements may have the consequence of discouraging the use of depleted oil and gas reservoirs.

EPA's Mandatory Greenhouse Gas Reporting rules under Subpart RR and UU require that the operator monitor the volume and quality of CO_2 being injected. In addition, the rule requires facilities conducting geologic sequestration of CO_2 under Subpart RR develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. EPA estimates that the annual cost of reporting for each facility under Subpart RR is $320,000 compared to $4,000 under Subpart UU.[9]

b. NRDC, among others, has advocated that EOR operators utilizing CO_2 from power plants should be forced to move from Class II to Class VI wells. In fact, formal rulemaking comments made by Mr. Hawkins and NRDC were submitted for the record during our hearing. Some seem to suggest that it is simple to move from operating under an EPA Class II permit to a Class VI permit. Would such a transition be relatively simple?

EPRI's permitting experience to date is limited to preparing documentation for Class V well permit applications for our existing DOE funded projects. We do not have direct experience related to permitting of Class II or Class VI wells, or the transition from Class II to VI wells. With that said, a review of the EPA's draft guidance document on transitioning wells from Class II to VI operations indicates that the well owner or operator must comply with all Class VI requirements. Only certain components of the Class II well construction may be grandfathered into the Class VI program at the discretion of the EPA Program Director. The Class VI well standards are much more comprehensive and specific compared to the Class II requirements.

c. How difficult is it to obtain a Class VI permit? How many currently exist?

As noted earlier, EPRI does not have any direct Class VI permitting experience and, therefore, cannot comment on the difficulty of obtaining such a permit. No "final" Class VI permits have been issued to date, however, EPA recently issued four "draft" Class VI well permits for the FutureGen Alliance project on March 31, 2014. The FutureGen Alliance or any other person may comment on the draft permits. The public comment period will be open for 45 days. The EPA received the FutureGen permit applications on March 15, 2013.

5. During our hearing you were asked if a pipeline from the Northeast to the Midwest or Texas for sequestration of EOR was feasible. While you responded that such an undertaking could be possible from an engineering standpoint, my question relates to real-world feasibility.

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[9] United States Environmental Protection Agency, Fact Sheet for Geologic Sequestration and Injection of Carbon Dioxide: Subparts RR and UU, November 2010.

a. As a rule of thumb, pipelines costs $200,000 per mile per inch of diameter. So for example, a 12-inch pipeline would cost roughly $2.4 million per mile. So a two thousand mile pipeline of modest size would cost roughly $5 billion to construct.

Is this a cost EPA considers in the proposed rule? Is this a cost you would consider feasible?

My response to the question during the hearing was intended to highlight that CO_2 pipeline construction is feasible from a technical standpoint. We have the technology needed to construct and maintain pipelines of substantial length as demonstrated by the 278,000 miles of onshore and offshore natural gas transmission lines in the United States alone.[10] Approximately 3,500 miles of CO_2 pipelines have also been constructed for EOR purposes. The pipeline costs that you provided of $200,000 per inch-mile exceeds estimates published in the open literature for the U.S.by a factor of 2–4, which range from $50,000-$110,000 per inch-mile, including labor, materials and right-of-way costs, which vary by location.[11] Many factors must be taken into consideration when determining the economic viability of a CO_2 transportation and storage project, including the distance to the closest and highest quality geologic storage location (i.e., sink) and backup storage locations. For areas of the country where CO_2 storage is a challenge, a project developer will need to weigh the cost/benefit of storing CO_2 in the best available sink for compliance versus building a longer pipeline to an EOR project where revenue may be realized from the sale of CO_2.

b. Such a pipeline would also require a significant right of way along its two thousand mile path. How long would that take? Is there a federal authority that currently regulates interstate CO_2 pipelines? Does such a body have imminent domain authority over private land owners?

EPRI's pipeline experience is limited to the relatively short 12.2 mile, one off, fit-for-purpose pipeline constructed by Denbury Gulf Coast Pipelines LLC for our SECARB Citronelle research project in Alabama. Once the permits and right-of-ways were obtained, pipeline construction moved quickly to completion within 2–3 months. The following authorities were consulted or required permits during the design and construction of the pipeline:[12]

- National Environmental Policy Act (NEPA) – U. S. Department of Energy
- National Pollution Discharge Elimination System (NPDES) storm water registration – Alabama Department of Environmental Management
- Alabama Historical Commission (AHC) – cultural resource identification and disposition
- State Historic Preservation Office (SHPO) – cultural resource identification and disposition
- U.S. Fish and Wildlife Service (FWS) – consulted for threatened and endangered species

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[10] American Petroleum Institute (API) and the Association of Oil Pipe Lines (AOPL), 2007. Pipeline 101, http://www.pipeline101.com/Introduction/index.html

[11] Ortiz, D. S., C. Samaras, E. Molina-Perez, The Industrial Base for Carbon Dioxide Storage: Status and Prospects, Rand Corporation, 90 pp., Mar 15, 2013

[12] Esposito, R., C. Harvick, R. Shaw, D. Mooneyhan, R. Trautz and G. Hill, 2013. "Integration of pipeline operations sourced with CO2 captured at a coal-fired power plant and injected for geologic storage: SECARB Phase III CCS Demonstration," Energy Procedia, 37, 3068–3088, doi: 10.1016/j.egypro.2013.06.193

- Alabama Department of Conservation and Natural Resources (ADCNR) – consulted for threatened and endangered species
- U.S. Army Corps of Engineers (USACE) – waterbodies and wetlands protection
- U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) – regulates the design, construction, operation, maintenance, and spill response planning for regulated pipelines

Nordhaus and Pitlick (2009) indicate there is no current Federal siting or eminent domain regulatory scheme for CO_2 pipelines.[13]

c. Newly proposed changes to the Clean Water Act (CWA) will likely impact the viability of utilizing Nation Wide Permitting authorities-thus requiring thousands of CWA 402 and 404 related permits prior to construction of such a pipeline. Given the environmental reviews required, how difficult might it be to build just one of the many pipelines that would be required for a nation-wide system of CO_2 pipelines?

I am not familiar with the proposed changes to the CWA or the permits referred to in this question; therefore, I can't offer an opinion on this subject.

6. EPA and other proponents of the GHG NSPS point to sequestration at sites in Norway, Algeria, and Canada to claim that carbon sequestration is adequately demonstrated. Yet research cited in the NSPS looks specifically at these locations and concludes that a fullscale power plant would create 2-4 times more CO_2/year than was injected in these sites and that "there is truth to the often heard assertion that CCS has never been demonstrated at the scale of a large commercial power plant."

a. Would you say that geologic sequestration at the scale that would be required to comply with the NSPS has been "adequately demonstrated"?

As noted in my written testimony, there are currently no full-scale, carbon capture and CO_2 storage projects in the world that are fully integrated with a fossil-fuel fired power station. EPRI's experience has been that full-scale operating experience is essential to assuring that a technology is fully viable at necessary levels of performance and reliability.

b. Recently, Assistant Secretary for Fossil Energy, Julio Friedman, explained that we would need hundreds of full scale power plants capturing and storing carbon to make a meaningful impact on atmospheric CO_2 concentrations. Setting aside the costs of the capture portion of CCS systems, what are the largest challenges to implementing CCS at such a scale? Are there any unknowns?

Full-scale deployment of CCS on a national scale envisioned by Assistant Secretary for Fossil Energy, Julio Friedman, would result in additional technological challenges. Multiple power plants injecting CO_2 into the same storage reservoir would result in pressure interference,

[13] Nordhaus, R.R. and E. Pitlick, 2009. Carbon Dioxide Pipeline Regulation, Energy Law Journal, v 30:85, p. 85-103.

causing reservoir pressures to buildup more rapidly potentially limiting injection rates for newer plants coming on line. This could lead to competition for available storage reservoirs or require injection well fields be placed further apart to avoid pressure interference. In addition, there may also be other, non-technical unknowns, e.g. CO_2 pipeline expansion, potential procurement barriers related to high demand for material, solvents, sorbents, etc. to support such a scale.

Responses by Mr. Scott Miller

CITY UTILITIES

Bringing Power Home.℠

April 15, 2014

The Honorable David Schweikert
Chairman
Subcommittee on Environment
Science Committee
2321 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Cynthia Lummis
Chairman
Subcommittee on Energy
Science Committee
2321 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairmen Schweikert and Lummis:

Thank you for the opportunity to testify last month at the joint Subcommittees on Environment and Energy hearing entitled the *Science of Capture and Storage: Understanding EPA's Carbon Rules*. It was a great honor to speak to the Members of the two subcommittees on City Utilities of Springfield's (CU) experiences with the Missouri Shallow Carbon Sequestration Demonstration project and the American Public Power Association's (APPA) concerns with the Environmental Protection Agency's (EPA) conclusion that carbon capture and sequestration (CCS) is the best system of emissions reduction (BSER) adequately demonstrated to reduce carbon dioxide (CO_2) emissions from new fossil fuel-fired power plants.

Attached are my responses to your questions for the record. If you have any questions about my responses, please let me know.

Sincerely,

Scott Miller
General Manager

Attachment

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<u>Responses to Science Committee Questions – Follow-up to CCS Hearing</u>

<u>Question 1</u> – Prior to public release of the NSPS rule, the Office of Management and Budget circulated it to other Federal agencies to provide feedback to EPA. That feedback resulted in <u>35 pages of comments that were published with the rule</u>—many of which were extremely critical. I want to zero in on one particular set of comments made by another agency. They said:

> EPA's proposal will have significant disparate geographic impacts. Geologic features appropriate for EOR or geologic sequestration are not evenly distributed throughout the country...
> ...the D.C. Circuit has said that sec. 111 standards "must not give a competitive advantage to one State over another in attracting industry."

<u>Question 1(a)</u> – Would you agree that the ability to do either EOR or geologic sequestration are very site specific, and many states and regions will simply not have EOR or sequestration options?

City Utilities agrees that the ability to do either enhanced oil recovery (EOR) or geologic sequestration are very site specific, and many states and regions will simply not have EOR or sequestration options. Our own experience as a participant in the Missouri Shallow Carbon Sequestration Demonstration Project indicates that our local region (Southwestern Missouri) would be unsuitable for carbon sequestration, even though other parts of Missouri may prove suitable for this purpose.

A requirement that all new coal and natural gas fired power plants use CCS would certainly advantage a few states and disadvantage many others. Most states do not have the appropriate geology for the long-term injection and sequestration of CO_2 (i.e., storage for between 500-1,000 years). Nor do they have the option to employ EOR, which is conditioned by the availability of working petroleum operations. Most states also do not have laws that allow for the injection of a commodity or waste product into the subsurface. In fact, in most states, the only person that can decide what may go underground is the surface land owner. Thus, any injection of CO_2 underground that migrates into the subsurface of another landowner would be an illegal trespass. The lack of geology allowing for long-term storage of CO_2 and inability to contain that CO_2 within the subsurface of the utility's property significantly limit the ability of many states to sequester CO_2 underground or use it for EOR, which involves the recycling and movement of the CO_2 from location to location and does not constitute long-term storage.

<u>Question 1(b)</u> – Do you think this rule will put specific states and regions at a competitive disadvantage?

The rule would put specific states and regions at a competitive disadvantage if utilities operating in them are incapable of sequestering the CO_2 underground or using it for EOR. Utilities in these areas would either be prohibited from constructing coal-fired units altogether, thereby having to rely on more expensive forms of generation, or would have to construct – or in the case of City Utilities, pay someone else to construct and operate – long-distance pipelines to carry captured CO_2. In either case, residential and industrial customers in the affected region would experience significantly higher electric costs than similar utilities situated with convenient access to sequestration fields.

In addition, utilities operating in non-oil and gas states would have to build pipelines to transport CO_2 captured from their plants to states with EOR or geologic formations more suitable for long-term sequestration of CO_2.[1] While other states might have pockets of geologic formations with natural gas or oil, the limitations of the geology might preclude the construction of power plants with CCS at those

[1] The traditional oil and gas states are Texas, Oklahoma, New Mexico, Colorado, Louisiana, Wyoming, Pennsylvania, and Alaska.

locations. Thus, use of captured CO_2 from power plants for EOR will be limited to those states with significant EOR.

Electric utilities want their generation located near load for a variety of reasons, including electric reliability. If they are precluded from building new coal or natural gas-fired power plants because their local geology precludes the sequestration of CO_2, they will have to invest in pipeline infrastructure to transport the CO_2 to distant EOR locations or formations that can store it long term. Such infrastructure will require utilities to spend money that will lead to increased electric rates. Utilities in EOR areas would not bear the same costs.

Question 1(c) – Do you believe CO_2 pipelines can solve this problem?

Long-distance CO_2 pipelines would not totally solve the problem of competitive disadvantage. Although a pipeline network could provide access to remote storage locations, that access would come at the expense of building and operating the pipeline. Such a pipeline would have to be newly constructed of special materials to withstand the inherent properties of compressed CO_2.

Existing natural gas pipelines cannot be used to transport CO_2. Specialty pipelines are required to transport CO_2. There are approximately 3,900 miles of CO_2 pipelines in the U.S. today and more than half are privately held (i.e., not a common carrier pipeline). The owners of those pipelines are under no obligation to take and transport CO_2 from the power sector.

Neither the Department of Energy (DOE) nor EPA have done a pipeline assessment map that shows the available capacity on existing CO_2 pipelines, which only operate in limited number of states. Many CO_2 pipelines appear to be at full capacity for movement between oil and gas recovery locations in Texas, Wyoming, Oklahoma, New Mexico, Utah, and Colorado. Thus, they likely have little ability to move utility-captured CO_2. In addition, there are concerns in the EOR business with cross contamination from CO_2 from coal plants, which contain sulfur salts and other substances. The presence of those substances can cause regulatory uncertainty for CO_2 injections into Class II or Class VI wells under the Resource Conservation and Recovery Act (RCRA). RCRA provides for certain regulatory treatment of CO_2 and other hydrocarbon processing waste products or substances in the oil and gas sector that are not applicable to CO_2 from the power sector.

Question 2 – In your testimony, you discussed City Utilities' involvement with the Missouri Carbon Sequestration Project.

Question 2(a) – What is the significance of storing CO_2 in a gas phase as opposed to a supercritical fluid?

The most critical difference between storing CO_2 in a gas phase as opposed to a supercritical phase is the amount of volume required. A given mass or weight of any substance will occupy much more volume in the gaseous state than in the liquid state (for example, a given amount of water expands to 1,700 times its original volume when it becomes a gas at the normal boiling point and atmospheric pressure). Supercritical CO_2 has somewhat intermediate properties in that it has a density closer to a liquid, but it is still compressible like a gas.

Question 2(b) – Given this experience, are you confident that City Utilities would be able to build new generation in compliance with the NSPS proposal? Has EPA limited the public's opinion with this rule?

We have no confidence that City Utilities would be able at any time in the future to build a coal-fired power plant under EPA's proposed NSPS for new power plants. While City Utilities has no plans to build such a plant, the rule would in all likelihood, remove such an option from future consideration.

<u>Question 2(c)</u> – With natural gas as an affordable alternative, why would City Utilities want to build coal power? From a public power perspective, does limiting options raise any reliability concerns?

If natural gas were proven to be an affordable and reliable alternative, City Utilities might well decide to build a natural gas-fired power plant instead of coal generation in the future. In fact, City Utilities recently built a new 300 megawatt unit and considered both coal and gas before ultimately deciding to go with coal. Our concerns with gas during the planning process were related to the price fluctuations and seasonal supply instability of natural gas. Those concerns were borne out in the recently concluded winter of 2013-14, when natural gas prices spiked as high as $31 per million Btu (compared to coal prices of around $2.50) and major disruptions in the natural gas supply system led to widespread shortages and use curtailments in many parts of the country.

At a more fundamental level, City Utilities' managers need the flexibility to consider and choose the best fuel options for our customers and our system. While we might, as indicated, elect to build a new unit using gas instead of coal, our planning and analysis should be based on sound principles of economics, reliability, and responsibility, rather than artificial government mandates.

<u>Question 3</u> – If EPA finalizes this rule as proposed:

<u>Question 3(a)</u> –What are the implications for your customers – as City Utilities retires older coal plants and adds new sources of power?

While City Utilities has no plans to retire any coal-fired units or other generating assets at present, we must recognize that our existing fleet will have to be replaced at some point in the future. If we are foreclosed from replacing existing coal units with similar technology in the future, our rates and reliability will likely be negatively affected, particularly during the winter months, when U.S. natural gas infrastructure is strained to its limits, as we recently witnessed this winter. From an economic perspective, total reliance on natural gas for electric generation would force our customers to pay twice for seasonal gas price spikes. Our natural gas customers already see this effect in the winter when residential and commercial heating demand causes gas prices to escalate and utility bills to increase. Our electric customers would also see similar price increases if we had to generate primarily from natural gas.

We worry that an over-reliance on natural gas for electric generation could result in periodic brownouts or blackouts due to the inability of the gas delivery system to supply our fuel demands. We have seen this happen on numerous occasions in the past and as recently as March of this year. These can occur due to a lack of pipeline capacity or to catastrophic disruptions, such as pipeline equipment failure, tear-outs, fires, etc. Prior to the Fuel Use Act of 1978, City Utilities was reliant on natural gas as a generating fuel and had to deal with such disruptions on a normal basis. Fortunately, we were able in those times to continue generation because we were equipped with coal backup capabilities. Another major difference between 1978 and today is that we now have 263 customers who have registered life support systems in their homes. These customers rely on electric supply as a matter of life and death.

<u>Question 3(b)</u> – Is City Utilities facing deadlines for other EPA rules that may compound reliability concerns or other impacts?

City Utilities is facing an April 2015 deadline to install air pollution control equipment under EPA's Mercury and Air Toxics (MATS) rule. Installation on three of our six older coal-fired units is expected to take longer than this and we have been granted a one-year compliance extension by the State of Missouri. At this point, we do not believe we will need to apply for a second extension to ensure system reliability. However, the three remaining smaller units are being relegated to standby duty as a result of this rule and the Industrial Boiler MACT rule, and will revert to natural gas as a primary fuel. This move engenders all of the reliability risks delineated above.

We also face a host of additional regulatory actions directed by EPA at our coal-fired plants, but at this point cannot estimate their impact on unit or system reliability. Future and proposed rules that will impact our coal plants include, Clean Water Act Section 316(b) cooling water intake structures, effluent limitations guidelines, and coal combustion residuals. We are also impacted by EPA's regional haze rules and would be by its Cross State Air Pollution Rule, but for the fact that the D.C. Circuit Court of Appeals overturned it because the agency exceeded its authority under the Clean Air Act. We have no idea what EPA will propose in its place. In addition, all of these rules will likely face legal challenges that will add to our uncertainty. The inability to plan for the impact and timing of these rules may have as much bearing on system reliability as the ultimate rules will.

Question 3(c) – If you are unable to add new coal or natural gas capacity, what might this mean for your customer's electric bills?

Currently, coal and natural gas units account for approximately 70% of the nation's generation. If we were limited from considering these U.S.-based fuels as options, nuclear is a tough option for us due to scale. We would be left with limited options such as buying power on the market through Southwest Power Pool, a move that removes supply from our community's control. This will change our cost and reliability profiles for the worse. Ultimately we believe it would negatively impact our community from an economic development perspective.

Question 4 – In your testimony, you stated that EPA's "failure to examine the non-air environmental consequences of CCS is a blatant violation of the letter and spirit of the Clean Air Act and the public's trust." That is a serious allegation. What are some examples of non-air environmental consequences the agency failed to consider?

There are many cross-media issues EPA failed to examine, including: (1) hazardous substance and superfund implications for environmental releases; (2) potential surface water contamination; (3) potential impacts to navigable waters and surface water flow; (4) Endangered Species Act implications; (5) land planning; (6) seismic activity; (7) natural resource depletion; and (8) resolution of underground access and trespass concerns.

For example, on the issue of potential Super fund liability, EPA has ignored the fact that CO_2 is an acid gas. Injecting it into the ground could change the pH of the soil or water receiving it. Such a change to pH change could trigger a Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund) remediation action. Other industries have been held liable for comparable changes to soil pH. For example, the dry cleaning industry faced CERCLA lawsuits for the release of dry cleaning solvents through sewer systems and where, it was alleged, that the solvents changed the pH.

There is no evidence in the proposed NSPS rule or accompanying Technical Supporting Documents that the Office of Air and Radiation consulted with the Office of Solid Waste and Emergency Response on the Superfund implications of sequestering CO_2. Nor has the agency addressed whether utilities injecting CO_2 would be given indemnification from liability for any potential environmental harm under

Superfund. EPA has been briefed on this issue by APPA and others many times between 2009 and 2014. The agency cannot assert it is unaware of the issue.

Another issue EPA has failed to look at is the creation of sulfur salts from the capture of CO_2 from power plants that generate with integrated gasification combined cycle (IGCC) technology where coal is gasified. There is nothing in the record that shows that the Office of Air and Radiation has met with the Office of Waste and Emergency Response to discuss the disposition of such salts. While there is a market for sulfur salts today, it is limited. It is very unclear whether it would be able to handle the large number of salts future IGCC plants with CCS would create. Thus, these surplus sulfur salts would need to be treated as waste and placed in either a solid waste landfill or hazardous waste landfill if the sulfur salts did not pass the toxicity characteristic leaching procedure (TCLP).

EPA has also not consulted with the U.S. Fish and Wildlife Service (FWS) regarding the potential impact of sequestered CO_2 on endangered and threatened species. When asked by the House Science Committee and Senate Environment and Public Works Committee at hearings on March 12 and April 8, 2014, respectively, Acting Assistant Administrator Janet McCabe stated EPA has not spoken with FWS about these potential impacts. She gave no reason for EPA's failure to do so.

Another issue EPA has failed to look at is the creation of sulfur salts from the capture of CO_2 from power plants that generate with integrated gasification combined cycle (IGCC) technology where coal is gasified. There is nothing in the record that shows that the Office of Air and Radiation has met with the Office of Waste and Emergency Response to discuss the disposition of such salts. While there is a market for sulfur salts today, it is limited. It is very unclear whether it would be able to handle the large number of salts future IGCC plants with CCS would create. Thus, these surplus sulfur salts would need to be treated as waste and placed in a solid waste landfill (or hazardous waste landfill only if the sulfur salts did not pass the toxicity characteristic leaching procedure). (We have no reason to believe that sulfur salts would create this new regulatory issue but we are simply identifying it as one of the many that EPA did not look at).

As my written testimony states, on December 4 and 5, 2013, EPA's SAB raised concerns about the scientific and technological bases EPA relied upon when proposing to mandate CCS for NSPS for new coal-fired power plants. Specifically, the SAB expressed concern with the peer review process of the DOE studies that were relied upon in the proposed rule, how the agency came up with its emissions limits for new coal- and natural gas-fired power plants, and the fact that the proposed rule does not address the sequestration side of CCS. EPA responded to those concerns by asserting that regulatory mechanisms for addressing sequestration were outside the scope of Clean Air Act and thus do not need to be addressed in the NSPS for new fossil fuel-fired power plants. Agency staff stated that only the capture side of CCS needs to be addressed.

The SAB, in a letter to EPA Administrator Gina McCarthy, dated January 29, 2014, stated it "defers to EPA's legal view...that the portion of the rulemaking addressing coal-fired power plants focuses on carbon capture" because that is all that is within the scope of the Clean Air Act. The letter notes, however, that "carbon capture is a complex process, particularly at the scale required under this rulemaking, which may have multi-media consequences." The board expressed its strong view that "a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in important systematic ways to this rulemaking." It encouraged EPA to have the National Research Council review the research and information on sequestration conducted by it, DOE, and other sources.

While SAB deferred to EPA's legal interpretation of its authority to look at cross-media issues rising from sequestration of CO_2, it is significant that the SAB raised these concerns. It is clear that several members of the SAB agree with APPA that these issues need to be resolved before CCS is declared BSER.[2]

Question 5 – Issues like long-term legal liability, mineral rights, pore space ownership, cross-state CO_2 plume migration, transport rights of way, and permitting authorities all remain largely unanswered. These risks, unknowns, and uncertainties with saline storage could pose serious problems. What steps has EPA taken to resolve these issues?

To APPA's knowledge, EPA has made no attempt to address legal liability, differences in state mineral rights laws (or their lack of existence), pore-space concerns, and cross-state CO_2 plume migration issues. APPA raised these issues with EPA more than a dozen times in person and in writing in several EPA dockets, including those on the Underground Injection Control (UIC) program, NSPS, and climate change policy in general. Further, ten witnesses spoke before the EPA Science Advisory Board (SAB) on the enormous obstacles to the adequate demonstration of this technology in January 2014. Thus far, EPA has ignored their concerns on these issues. In addition, on February 6, 2014, a representative from the American Petroleum Institute (API) spoke to EPA about the dramatic differences between EOR/enhanced gas recovery (EGR) in the oil and gas sector and the presumption of the adequate demonstration of CCS for the power sector. He offered to provide EPA with a detailed briefing on the significant differences between long-term sequestration of CO_2 and EOR.

The committee should look to the American Water Works Association (AWWA) on the possible or potential uses of saline aquifers. AWWA represents both public and private entities that provide drinking water to the public. Many APPA members provide both electric and drinking water services as municipal agencies and are also members of AWWA. In the summer of 2009, APPA and AWWA briefed EPA's Water Office on shared concerns regarding the presumption that CO_2 could be stored permanently underground for the power sector. APPA and AWWA offered to brief EPA's Office of Air and Radiation. Unfortunately, the offer was rejected by EPA staff.

[2] Per the request of the SAB, APPA sent a letter to it on December 9, 2014, outlining our concerns with the many obstacles to commercial demonstration of sequestration. The letter can be viewed at http://www.publicpower.org/files/PDFs/APPA%20Letter%20to%20EPA%20on%20SAB%20--%20FINAL%20--%2012-9-2013.pdf.

Responses by Ms. Janet McCabe

Questions for the Record following March 12, 2014, Hearing on the Science of Capture and Storage: Understanding EPA's Carbon Rules

The Honorable David Schweikert

1. At a hearing before the House last month, DOE Deputy Assistant Secretary for Clean Coal, Dr. Julio Friedmann, testified that requiring CCS technologies at new coal-fired plants could dramatically raise the cost of electricity for consumers.

Dr. Friedmann said that for so-called first generation technologies, there would be "something like a 70 to 80 percent increase on the wholesale price of electricity." Dr. Friedmann added that "It is in fact a substantial percentage increase in the cost of electricity..."

a. Does the EPA agree with that statement?
b. Does the NSPS proposal align with that assessment? Why or why not?
c. Is a 70 to 80 percent increase on wholesale power prices acceptable to the EPA?
d. How did EPA model the economic impacts of such an increase?

RESPONSE: The Environmental Protection Agency believes that, because the proposed new source carbon pollution standards are in line with current industry investment patterns, they would not have notable costs and are not projected to impact electricity prices or reliability. To the extent that a utility does elect to construct a new coal plant with carbon capture and sequestration (CCS) to meet the EPA's proposed standards, the standards can be met with partial CO_2 capture, which would have much lower costs than those described by Mr. Friedman which were based on an assumption of full CO2 capture. Also, the construction of new coal capacity with CCS would likely coincide with opportunities for revenue from the sale of captured carbon, for example for enhanced oil recovery, which would mitigate the CCS costs. Additionally, the costs associated with a single plant do not significantly change retail prices paid by consumers, which are derived based on the cost of generation and transmission across the power system.

The EPA's assessment of partial capture CCS, found that:

- **For a new supercritical pulverized coal (SCPC) power plant, the change in the levelized cost of electricity (LCOE) ranges from a decrease of $4/MWh (4%) with a relatively high market value for enhanced oil recovery (EOR) to an increase of $18/MWh (20%) assuming no market for EOR. It is important to note that the climate and co-benefits associated with partial CCS on SCPC ranges from $16-$22/MWh (assuming 3% Social Cost of Carbon (SCC)).**
- **For a new integrated gasification combined cycle (IGCC) facility, the change in the LCOE ranges from no difference in cost with a relatively high market value for EOR to an increase of $12/MWh (12%) assuming no market for EOR. The climate and co-benefits associated with partial CCS on IGCC is approximately $7.5/MWh (assuming 3% SCC).**

- **Note that the LCOE ranges provided above are costs of electricity from the referenced plant only – they do not reflect changes in economy-wide electricity prices which are not heavily influenced by energy prices from a single generating facility.**

2. You testified that the Agency believes that CCS systems have been "adequately demonstrated" as a technology for reducing CO_2 emissions from fossil fuel-fired power plants. However, there is no fully operational coal-fired power plant in the world currently using CCS technology.

   a. Can you provide any other example of a technology required by EPA CAA section 111 regulations where the technology was **not** yet used on a commercial basis?

RESPONSE: In previous NSPS regulations, the EPA set limits based on analysis of technologies, their capability, and whether they could be transferred between similar processes. For example, in the 1990's, the EPA used selective catalytic reduction (SCR) to set NSPS for industrial boilers and utility boilers. At that time, SCR had been used on boilers in the United States and internationally. In the United States, SCR was used on just a few utility boilers, but not on industrial boilers. Some commenters suggested that SCR was not adequately demonstrated for industrial boilers, and therefore could not be the best system. They also claimed SCR would be too expensive. However, the unit and technology configuration was practically identical between the industrial and utility boilers. Because of how similar the technology was, the EPA used data and analysis from both types of units to set the limits. That is similar to the proposed Carbon Pollution Standards, with an important difference: CCS has been, or is in the process of being, used on utility units at or beyond the level we have proposed.

   b. EPA is explicitly required to consider cost in determining best technology available. By EPA's own estimate, adding CCS to a new coal-fired power plant adds somewhere between 60% and 80% to the total cost of the plant. How does this compare to the percentage increase in costs imposed by other control technologies EPA has required in the past?

RESPONSE: Our Regulatory Impact Analysis for the proposed Carbon Pollution Standards compares the levelized cost of electricity for new units across different generation technologies, including coal-fired generation with and without CCS. This assessment shows that super-critical pulverized coal generation (SCPC) costs about $92 per MWh (with climate uncertainty adder) and that integrated gasification combined cycle generation (IGCC) costs about $81 per MWh (without climate uncertainty adder). Our assessment of CCS on new units shows that SCPC with CCS costs between $88 and $110 per MWh while IGCC with CCS costs $97 - $109 per MWh depending on economic opportunities for carbon utilization and storage.

c. Would it be fair to say the costs for compliance with this single requirement would exceed the combined cost for all other CAA technologies required by EPA on new coal-fired power plants?

RESPONSE: New capacity projections from the EPA and EIA indicate that the proposed Carbon Pollution Standards are not projected to require changes in the design or construction of new EGUs from what would be expected in the absence of the rule. Thus, under both the baseline projections, as well as alternative AEO 2013 scenarios, the proposed standards are not projected to result in any emission reductions, monetized benefits, or costs.

3. In the proposal, EPA determined that partial CCS is BSER for coal but not for natural gas fired EGUs. The BSER analysis and factors EPA considered in making these contrasting determinations is strikingly different between the two categories. EPA appears to suggest that the legal framework for making BSER determinations changes based on the current economics of different fuel options.

a. Is this EPA's legal position? If so, on what authorities does this legal rationale rely?
b. Are there other variables that EPA believes would impact the factors the Agency considers in making a BSER determination?
c. <u>To what extent</u> is cost a determining factor?
d. What assumptions were made about the cost of natural gas and coal? Was this done regionally or does EPA assume that prices are uniform nationally?
e. At what price does coal power become competitive or advantaged over natural gas?
f. Have prices changed since the initial release of this proposal in September of 2013?
g. Are long-term contracting or stockpiling options the same for coal and natural gas?
h. How will the agency's conclusions change when these costs factors change substantially?

RESPONSE: Section 111(b)of the Clean Air Act (CAA) requires the EPA to identify the "best system of emission reduction ... adequately demonstrated" (BSER) available to limit pollution. The CAA and subsequent court decisions identify the factors for the EPA to consider in a BSER determination:

- **Feasibility: The EPA considers whether the system of emission reduction is technically feasible.**
- **Costs: The EPA considers whether the costs of the system are reasonable.**
- **Size of emission reductions: The EPA considers the amount of emissions reductions that the system would generate.**
- **Technology: The EPA considers whether the system promotes the implementation and further development of technology.**

Cost is one of many considerations evaluated as part of a BSER determination, but the legal framework for determining BSER does not change as costs change. In the proposed Carbon Pollution Standards, the EPA analyzed the costs of both natural

gas and coal generation, including fuel prices. As detailed in the Regulatory Impact Analysis (RIA), the proposal accounts for projected regional coal and natural gas prices. The national average delivered prices for coal and natural gas used in this assessment are $2.94/MMBtu and $6.11/MMBtu (in 2011 dollars), respectively. In addition, the Agency also used a variety of sensitivity cases and alternative assumptions to demonstrate that the conclusions expressed in the proposal hold true at a wide range of natural gas prices.

The RIA also shows that new coal-fired generation without CCS approaches parity with new natural gas only when natural gas prices exceed $10/MMBtu on a levelized basis (in 2011 dollars). None of the EPA sensitivities or AEO 2013 scenarios project national average natural gas prices near that level. Industry investment patterns and the EPA's assessments are based on longer-term, annual projected fuel prices. Fluctuations in shorter-term prices over periods up to a year or two are influenced by a variety of factors, and are typically managed through a variety of hedging instruments matched to the corresponding period and pattern of spot prices. The Technical Support Document (TSD) accompanying the proposal entitled *Trends in Structure of Electric Power Sector Limiting Amount of New Coal* discusses the short term price volatility of both natural gas and coal.

Additionally, contracting and stockpiling options are similar in the coal and natural gas industries, but vary as a function of the different industry structures. The EPA considered the types of stockpiling options in making its assessments.

4. Do regulated parties have an interest in "fuel diversity"? Would such an interest support construction of coal fired power plants in the absence of the proposed NSPS?

RESPONSE: Integrated Resource Plans (IRPs) from utilities as well as some of the comments on the April 2012 proposal suggest that many utilities find value in factors such as fuel diversity and are willing to pay a premium for it. These IRPs suggest that a range of technologies can meet the preference for providing intermediate or base-load power from a diverse fuel mix.

As explained in the RIA for the proposed Carbon Pollution Standards, available data indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions mean that few, if any, solid fossil fuel-fired EGUs will be built in the foreseeable future; and (ii) electricity generators are expected to choose new generation technologies (primarily natural gas combined cycle) that would meet the proposed standards.

5. In some regions of the United States, would the proposed NSPS prevent the construction of new coal-fired power plants or make the construction of such plants more expensive?

RESPONSE: The proposal would not prevent the construction of new coal-fired power plants. A number of projects are currently under construction that would meet this standard and several more are under development.

6. EPA's proposed rule states that the levelized cost of electricity (LCOE) for partial CCS is "comparable to other non-NGCC generation, after accounting for revenue from the sale of CO2 for EOR." EPA states that "[w]hen considered against the range of costs that would be incurred by projects deploying non-natural gas-fired electricity generation, the implementation costs of partial CCS are reasonable."

It is apparent that not everyone shares this assessment. For example, while the Energy Information Administration (EIA) considers LCOE to be "a convenient summary measure of the overall competitiveness of different generating technologies" it notes that "actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations." EIA further stated that "[s]ince projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives."

a. Please provide any records demonstrating that EPA considered and/or rejected EIA's January 2013 assessment of LCOE.
b. Do you believe that use of LCOE in CAA rulemaking can be "problematic" and/or "misleading"? If not, please provide the committee with the technical basis for this assessment and your accompanying economic rationale.
c. EPA claims to have considered the costs of various BSER alternatives and to have rejected several lower cost options on the basis that they would not result in "significant reductions" in GHG emissions. What does EPA consider to be an acceptable cost-per-ton of CO_2 removed from utility electric generating units (EGUs)?

RESPONSE: LCOE is a widely used metric that represents the cost, in dollars per output, of building and operating a generating facility over the entirety of its economic life. Evaluating competitiveness on the basis of LCOE is particularly useful in establishing cost comparisons between generation types with similar operating characteristics, but with different cost and financial characteristics. The EPA has not established a cost-per-ton threshold in this proposal. The EPA has proposed to determine that CCS is technically feasible for new coal-fired power plants, because all of the major components of CCS – the capture, the transport, and the injection and storage – have been demonstrated and are currently in use at commercial scale.

The analysis that the EPA performed for this proposal concerning costs is available in the rulemaking docket. The EPA will review comments on various metrics that the agency should consider, and evaluate and consider those in a final rulemaking.

7. Acting Assistant Secretary for Fossil Energy, Chris Smith, was asked by several Senators at a recent Senate hearing about his opinion on whether carbon capture and storage (CCS) is currently commercially available for power plant applications. In response he answered that "[all] components of CCS ... have been demonstrated worldwide" and that "[t]here are twelve large-scale CCS projects in operation worldwide today."

You also noted that the Agency relied on 12 large CCS projects.

a. Are any of these twelve projects a full-scale, base-load electric power plant?
b. Do any of these projects currently have a Class VI well permit?
c. For each of these 12 projects, please provide the Committee with:

1. A general description of the project, its location, and the electric generating capacity of the project, and the specific type of fuel the project uses.
2. The approximate date any planning initially began for the project or a previous iteration of the project.
3. The current status of the project.
4. Estimated completion date of the project.
5. Planned operating life of the project.
6. A technical description of the capture technologies, including detailed disclosure of any chemicals used in these systems.
7. Documentation of any commercial guarantees for capture technologies used in conjunction with any projects receiving federal funding.
8. Volume of CO2 currently captured; the annual volume of C02 anticipated to be captured when fully operational; and the total volume of C02 anticipated to be captured over the lifetime of the project.
9. Explain where, how, and under what regulatory and reporting systems the C02 will be stored.
10. The total federal, state, or municipal financial assistance the project has received or anticipates obtaining. Please include any grants, tax incentives, loan grantees, or rate recovery mechanisms.
11. Explain the parasitic load factor of the entire carbon capture, compression, transport, and storage system. Explain how this impacts the efficiency of the project as compared to the project without CCS.
12. Explain how the project foot print is impacted by the CCS system.
13. Provide the percentage of the overall cost of the project that is predominately related to the CCS portion of the project.
14. List any objections made to the project by any stakeholders, environmental groups, NGOs, or other individuals. Provide petitions for any challenges or objections that are currently pending. For any objections that have been resolved, provide concessions or alterations made that allowed the project to move forward.

RESPONSE: The EPA's proposed standards rely on a wide range of data, information and experience well beyond that generated by particular projects or studies. The EPA has proposed to determine that CCS is technically feasible for new coal-fired power plants because all of the major components of CCS – the capture, the transport, and the injection and storage – have been demonstrated and are currently in use at commercial scale. For example there are several industrial projects in the U.S. that are currently capturing the CO2 for use in enhanced oil recovery (EOR) or other applications. There have been numerous smaller-scale projects that have demonstrated the technology, and there are several full-scale projects – both in the U.S. and internationally – that are under construction today. The information that the EPA relied on to make this determination is available in the preamble for the rule and the technical support document (TSD) available at this link: http://www2.epa.gov/sites/production/files/2014-01/documents/2013_proposed_cps_for_new_power_plants_tsd.pdf. Thus, the EPA has proposed to determine that partial CCS is the Best System of Emission Reduction (BSER) for new coal-fired power plants.

As of August 29, 2014, the EPA has issued four final Class VI well permits.

8. The proposed rule relies heavily on the potential for power plants to sell CO_2 to enhanced oil recovery (EOR) operators as a means of defraying the tremendous costs of CCS. However. EOR operators are signaling that the Subpart RR requirements in the proposed rule may be prohibitive.

A broad coalition of groups, from EOR operators to electric power providers, has raised concerns about EPA's plans. For example, the Committee received a letter from the Electric Reliability Coordinating Council (attached). Other members have submitted documents from companies like Denbury – each representing a range of companies and groups with concerns about the efficacy of EOR in relation to this rule.

a. Please explain in detail the new requirements for EOR operators that would accept CO_2 from power plants?
b. Have you spoken with any groups potentially impacted by the new Subpart RR reporting requirements? How have you taken their concerns into consideration?
c. Would reporting under Subpart RR potentially trigger the transition of an EOR well from Class II to Class VI under the UIC program-as EPA draft guidance suggests?
d. Since a significant part of EPA's economic justification for the proposed rule relies on the assumption that the CO_2 from power plants will be a valued commodity used in EOR operations: How do the economics of the proposed rule change if this is no longer an option?
e. Can you commit that EPA will not use reporting under Subpart RR to push any EOR operations into Class VI.

RESPONSE: The proposed Carbon Pollution Standards rely on the existing EPA requirements that are already in place for monitoring and permitting CO2 injection and geologic sequestration. Under the proposed Carbon Pollution Standards, if a new power plant decides to use CCS to comply with the standard, captured CO2 must be sent to a facility that meets the existing regulatory requirements for monitoring and reporting geologic sequestration. The EPA has an existing permitting framework in place under the Safe Drinking Water Act governing these kinds of projects and has been working closely with states and some facilities in the permitting process. A number of projects have been permitted under the existing regulatory framework, providing valuable experience and technical information to the EPA and states.

To be recognized as conducting geologic sequestration under the existing requirements (Subpart RR of the Greenhouse Gas Reporting Program), all facilities, including EOR, must conduct monitoring and reporting to show that the CO2 remains underground. For CO2 that is not recognized as being sequestered, EOR facilities can continue to report under the requirements for CO2 injection (Subpart UU of the Greenhouse Gas Reporting Program). The EPA believes that it is appropriate to rely on these same, existing requirements for the proposed new source rule, and will closely evaluate comments that we receive on this issue.

The regulations promulgating Subpart RR were finalized in 2010. The EPA spoke with stakeholders during the development of the requirements and carefully reviewed and responded to public comments as part of the rulemaking process that promulgated the Subpart RR requirements. An EOR project reporting under Subpart RR may be permitted as UIC Class II; it is not required to obtain a Class VI permit based on reporting. The regulatory provisions regarding transitioning from UIC Class II to UIC Class VI are set forth at 40 CFR 144.19 and focus on ensuring protection of Underground Sources of Drinking Water. Reporting under Subpart RR of the Greenhouse Gas Reporting Program is not one of the factors specified in 40 CFR 144.19(b).

9. EOR is not an option in many parts of the country, and geology is often unpredictable. EPA and others have suggested that new C02 pipelines could solve this problem. For example, portions of the Northeast that do not have access to an EOR market, or perhaps the right geology or legal structures for geologic sequestration, could build pipelines to states like Texas that could provide a market for C02 to be used in EOR.

   a. As a rule of thumb, pipelines costs $200,000 per mile per inch of diameter. So for example, a 12-inch pipeline would cost roughly $2.4 million per mile. So a two thousand mile pipeline of modest size would cost roughly $5 billion to construct. Is this a cost EPA considers in the proposed rule? Does EPA consider this cost feasible?

b. Such a pipeline would also require a significant right of way along its two thousand mile path. How long would that take? Is there a federal authority that currently regulates interstate C02 pipelines? Does such a body have imminent domain authority over private land owners?

c. Could newly proposed changes to the Clean Water Act (CWA) impact the viability of utilizing Nation Wide Permitting authorities-thus requiring thousands of CWA 402 and 404 related permits prior to construction of such a pipeline? Given the environmental reviews required, how difficult might it be to build just one of the many pipelines that would be required for a nation-wide system of C02 pipelines? How did EPA take this into consideration?

d. Did EPA consider the potential non-air environmental impacts of the proliferation of CO2 pipelines?

RESPONSE: Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO_2 point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site, which would lower transportation costs.

There are multiple factors that contribute to the cost of CO_2 transportation via pipelines including but not limited to: availability and acquisition of rights-of-way for new pipelines, capital costs, operating costs, length and diameter of pipeline, terrain, flow rate of CO_2, and the number of sources utilizing the pipeline. At the same time, studies and DOE quality guidelines have shown CO_2 pipeline transport costs in the range of $1 to $4 dollar per ton of CO_2. For these reasons, the transportation component of CCS is well-established as technically feasible and is not a significant component of the cost of CCS.

Furthermore, the EPA took comment on and companies are actively pursuing storage options that do not involve geologic sequestration. The EPA is reviewing the information or data on this issue that we receive during the public comment period.

10. This Committee is familiar with the communications between the Science Advisory Board and the Administrator as well as the meetings held in December 2013 and January, 2014 addressing CCS. The EPA staff who spoke on your behalf at that December 4-5, 2013 meeting said that looking at sequestration was outside their statutory obligation since other EPA programs would handle the storage or sequestration of the CO2.

Yet we can find no evidence of any cross media research conducted by the Office of Water or Office of Solid Waste to address the injection and storage of the C02 from new power plants. Your proposed rule's Technical Supporting Documents and other materials for the rulemaking point to the Class II programs for oil and gas injection wells. But for new coal-fired or perhaps even natural gas-fired power plants, EOR is not helpful because they would not be located in states with oil and gas operations.

a. Please explain how future power plants would be permitted for C02 injection in parts of the country where EOR is not an option. What portion of the storage costs and liability will EPA be willing to subsidize? How did EPA assess these costs?
b. The NSPS proposal notes that UIC Class VI wells are an option. How many Class VI permits has the agency granted to date?

RESPONSE: Facilities using carbon capture are doing different things with the captured CO_2, ranging from EOR to storage to using it for food products. While it is true that selling captured CO_2 for EOR can generate revenue and help offset the costs of capturing carbon, this does not mean power plants can only build in areas near EOR.

As of August 29, 2014, the EPA has issued four final Class VI well permits.

11. Over the past few months, EPA staff told the Science Advisory Board that it was not allowed to examine EPA's assessment of injection and sequestration aspects of the proposed NSPS rulemaking.

a. Why was the SAB instructed to ignore sequestration issues?
b. How can the Agency both rely on the benefits of EOR sales for making a CCS system less expensive, and incorporate new storage requirements in the rule (Subpart RR) while simultaneously denying that CCS includes the storage half of the system?

RESPONSE: While the EPA has confidence that geologic sequestration is technically feasible and available, we recognize the need to continue to advance the understanding of various aspects of the technology. We have engaged with the SAB on key issues relating to sequestration and look forward to continuing to collaborate with the SAB on this important topic to ensure that our work is based upon the best available science.

The proposed Carbon Pollution Standards rely on the existing EPA requirements that are already in place for monitoring and permitting CO2 injection and geologic sequestration. Under the proposed Carbon Pollution Standards, if a new power plant decides to use CCS to comply with the standard, captured CO2 must be sent to a facility that meets the existing regulatory requirements for monitoring and reporting geologic sequestration. The EPA has an existing permitting framework in place under the Safe Drinking Water Act governing these kinds of projects and has been working closely with states and some facilities in the permitting process. Pilot projects have been permitted under the existing regulatory framework, providing valuable experience and technical information to the EPA and states.

To be recognized as conducting geologic sequestration under the existing requirements (Subpart RR of the Greenhouse Gas Reporting Program), all facilities, including EOR, must conduct monitoring and reporting to show that the CO2 remains underground. For CO2 that is not recognized as being sequestered, EOR facilities can continue to report under the requirements for CO2 injection (Subpart UU of the Greenhouse Gas Reporting Program). The EPA believes that it is appropriate to rely on these same, existing requirements for the proposed new source rule, and will closely evaluate comments that we receive on this issue.

After consideration of the clarifying information and thorough discussion about the issues during several meetings of the SAB that were open to the public, the workgroup recommended to the full SAB that additional review of the science of sequestration was not necessary in the proposed Carbon Pollution Standard. The full SAB agreed with the workgroup's assessment that the EPA did not propose to set any new requirements for sequestration in the Carbon Pollution Standards and that peer review of the DOE cost studies was sufficient. In a memo dated January 29, 2014, the SAB informed the EPA that it will not undertake further review of the science supporting this action.

12. In June of 2013, DOE released a "Mitigation Action Plan for the W.A. Parish Post-Combustion C02 Capture and Sequestration Project." (attached). In this document, DOE explained that carbon storage "activities are included in this project description because they are integrated into the project concept and considered connected actions."

a. Does EPA fully agree with this assessment?
b. Please explain EPA's rationale and legal justifications.
c. If EPA does not fully agree with this assessment, has or will EPA object? Why or why not?
d. Provide any documentation that EPA considered this or other determinations made by DOE or other agencies that CCS is a connected system that includes storage.

RESPONSE: The referenced report details the CO_2 capture project at the NRG W.A. Parish Plant near Houston, TX. The report describes the four primary components of the project to include: the CO_2 Capture Facility; the CO_2 Pipeline; the EOR Operations; and the CO_2 Monitoring Program. The use of captured CO_2 in EOR operations is an option that is discussed at length in the EPA's proposed Carbon Pollution Standards. The EPA has also discussed these components – the capture, the transport, the storage (in the case of the Parish project, utilizing the CO_2 for EOR), and the monitoring program – as being the major components of many CCS projects. However, the EPA also noted other opportunities for use of captured CO_2 that do not involve geologic storage – such as the Skyonic process that is discussed in the proposal.

13. At the January 21, 2014 SAB meeting, held by conference call, the EPA had speakers or witnesses from at least three utilities that discussed how CCS would not be feasible in their states for a number of reasons.

In one case, a speaker from New York State, explained that while they had adequate cap rock to hold the C02 into place in western New York, the operators realized that they could not get a performance warranty or guarantee for how much C02 could be injected. Further, the utility learned that the C02 injected would stretch beyond the subsurface owned by the city utility. Ultimately, they concluded that is not legal in the state of New York to inject C02 under another person's property. The project for CCS at that new coal-fired power plant was ceased as a result.

a. Does the Agency dispute the information presented by these witnesses or any others presented at this meeting?
b. Did EPA encourage the SAB to consider these comments? Why or why not.
c. Was EPA aware of the legal obstacles utilities face in many states?
d. Does EPA have the power to change these legal problems?
e. How did EPA factor in these obstacles?
f. What economic analysis did EPA undertake to understand the potential impacts of these practical and legal obstacles?

RESPONSE: The EPA welcomes public input on its proposed rules, and is currently reviewing comments on the proposed Carbon Pollution Standards.

In the proposal, the EPA has not mandated the use of CCS. Rather, the Agency has proposed emission standards that must be met by new electric generating units. State law may impose constraints on one or another type of facility, in which case different types of facilities can and will be built to meet needed electricity demand.

A new source developer would also have the option of transporting the captured CO2, via pipeline, to an area that is suitable for long term storage. Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO2 are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO2 point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site.

14. The sole source aquifer program is an excellent example of where consultation should take place, since it is administered by EPA not states. There are about 77 sole source aquifers in the United States where the populations of those communities rely upon that aquifer for drinking water for at least 50% of the population. In fact in the western part of the U.S. a few communities rely almost entirely upon sole source aquifers for drinking water. While EPA staff did not address sole source aquifers before the SAB, the EPA staff said that all <u>non-air issues would be addressed by other EPA regulatory programs</u>.

a. How did EPA address the cross statutory issues related to the injection and sequestration of CO_2 if the injection must go through a sole source aquifer?
b. Please explain how EPA's Office of Air and Radiation and EPA's Office of Water communicated and considered the impact of the proposal on EPA's own special program dedicated to protection of sole source aquifers?
c. Please provide any communications or other documentation of these inter-agency communications.

RESPONSE: The EPA's Office of Air and Radiation and Office of Water have worked closely for a number of years to develop a regulatory framework that can ensure long-term safe geologic sequestration. The EPA's Underground Injection Control (UIC) Program, established under the Safe Drinking Water Act, established requirements to ensure that geologic sequestration is conducted in a way that geologic sequestration wells are appropriately sited, constructed, tested, monitored, and closed in a manner that ensures protection of all Underground Sources of Drinking Water (including sole source aquifers). Thus, the location of a sole source aquifer would be a potential consideration for UIC permitting. The proposal does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC Program under the Safe Drinking Water Act.

15. On March 6, 2014 our colleagues from the Senate Environment and Public Works Committee inquired whether EPA had conducted any consultation with the Fish & Wildlife Service (FWS) regarding the Endangered Species Act (ESA) and whether a full analysis has taken place under the ESA.

As you are aware, Section 7 of the ESA requires the FWS consultation on any action that "may effect" a listed species or designated critical habitat. As the Senators pointed out, because the NSPS effectively removes coal as an option for electric power generation, the nation will need to rely on other energy resources, like nuclear, natural gas and renewables. This shift will certainly require additional habitat and the use of resources that have a history of harming endangered species.

You testified that EPA has not consulted with the FWS in regard to the proposed rule for new power plants.

a. Why did EPA choose not to consult with the FWS in drafting this rule?
b. Has EPA consulted with the FWS in regard to the upcoming existing source rule? Why or why not?

RESPONSE: Any final rules the Agency issues for carbon pollution from new or existing power plants will be based on sound science, will comply with all applicable legal requirements (including the Endangered Species Act), and will also address any significant comment we received on the applicability of the ESA.

16. You testified that since the components of CCS have been used by other industries, fully integrated CCS systems have been "adequately demonstrated" for power plants. But the GHG NSPS's own cited literature explains that "even when component technologies work well, they need to work well within an integrated CCS system." Isn't EPA's own research correct- isn't there a difference between demonstrating the components of CCS and demonstrating CCS as a fully integrated system?

RESPONSE: The EPA has proposed to determine that CCS is technically feasible for new coal-fired power plants, because all of the major components of CCS – the capture, the transport, and the injection and storage – have been demonstrated and are currently in use at commercial scale. For example there are several industrial projects in the United States that are currently capturing the CO2 for use in enhanced oil recovery (EOR) or other applications. There have been numerous smaller-scale projects that have demonstrated the technology, and there are several full-scale projects – both in the U.S. and internationally – that are under construction today. Thus, the EPA has proposed to determine that partial CCS is the Best System of Emission Reduction (BSER) for new coal-fired power plants.

17. EPA cites three studies in the "literature" section of the new standard's "technical feasibility" discussion of CCS. Yet, EPA leaves out that one of those studies concludes that "there is truth to the often heard assertion that CCS has never been demonstrated at the scale of a large commercial power plant." Another study assumes carbon capture is "unproven technology." And the other study- which EPA co-drafted – says that carbon capture has "not been demonstrated at a scale necessary to establish confidence for power plant application." How does EPA explain these apparent inconsistencies?

RESPONSE: EPA's proposed standards rely on a wide range of data, information and experience well beyond that generated by particular projects or studies. The EPA has proposed to determine that CCS is technically feasible for new coal-fired power plants because all of the major components of CCS – the capture, the transport, and the injection and storage – have been demonstrated and are currently in use at commercial scale. For example there are several industrial projects in the U.S. that are currently capturing the CO2 for use in enhanced oil recovery (EOR) or other applications. There have been numerous smaller-scale projects that have demonstrated the technology, and there are several full-scale projects – both in the U.S. and internationally – that are under construction today. Thus, the EPA has proposed to determine that partial CCS is the Best System of Emission Reduction (BSER) for new coal-fired power plants.

18. In EPA's first NSPS proposal in 2012, the agency determined that carbon capture and storage technology was not the best system of emissions reduction for new coal power plants. A year later, in this latest proposal, EPA says it is now the best system for emission reduction. Please explain with specificity exactly what changed in a year and a half to

allow EPA to reach a different conclusion on the technical and economic feasibility of CCS?

RESPONSE: The EPA received more than 2.5 million comments on the April 2012 proposed rule. Among the topics discussed in those comments was the degree to which CCS has been adequately demonstrated as BSER for coal-fired power plants. After the consideration of information provided in those comments, the EPA has proposed to determine that CCS is technically feasible for new coal-fired power plants, because all of the major components of CCS – the capture, the transport, and the injection and storage – have been demonstrated and are currently in use at commercial scale. For example there are several industrial projects in the United States that are currently capturing the CO2 for use in enhanced oil recovery (EOR) or other applications. There have been numerous smaller-scale projects that have demonstrated the technology, and there are several full-scale projects – both in the U.S. and internationally – that are under construction today. Thus, the EPA has proposed to determine that partial CCS is the Best System of Emission Reduction (BSER) for new coal-fired power plants.

19. Section 1-3 of NSPS Regulatory Impact Analysis, EPA stated that "even in the absence of this rule, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that meet the proposed standard without the need for additional controls."

a. If that is the case, why did EPA expend substantial resources adopting a rule that it asserts will have no impact on "new construction" of electric generation facilities?

b. EPA also states that it "anticipates that the proposed EGU New Source GHG Standards will result in negligible C02 emission changes, energy impacts, quantified benefits, costs, and economic impacts by 2022." Why is EPA engaged in a regulatory proceeding for which EPA's own analysis states will result in "negligible, quantified benefits, costs, and economic impacts by 2022"?

c. Why does EPA conclude that its NSPS proposal would "provide an incentive for supporting research, development, and investment into technology to capture and store C02" if EPA predicts that, even absent NSPS, there would be no new "coal-fired power plant" construction and thus no need to "implement[t] some form of partial capture and storage" for such plants?

d. What is the basis for EPA's recognition that "a few companies may choose to construct coal or other solid fossil fuel-fired units" in the absence of the proposed NSPS? *See* Section 1-3 of NSPS Regulatory Impact Analysis.

RESPONSE: Power plants are the biggest emitters of carbon pollution. This proposed rule will make sure any new power plants use modern technology to minimize this harmful carbon pollution. Because these standards are in line with current industry

investment patterns, these standards are not expected to have notable costs and are not projected to impact electricity prices or reliability. The Department of Energy, the EPA and industry projections indicate that new power plants that are built over the next decade or more would be expected to meet these standards even in the absence of the rule. EIA projections and EPA analysis indicate that utilities are most likely to choose to build new power plants that would already meet the standards proposed in this rule (natural gas or coal with partial CCS) or are not covered by this rule (renewables, nuclear, or simple cycle turbines that only sell a portion of their output to the grid).

20. Is it EPA's position that the proposed NSPS will have no tangible impact on the parties that it regulates?

a. If EPA believes that the proposed NSPS will have tangible impacts on regulated parties, what are those impacts?

b. If EPA believes that the proposed NSPS will have no tangible impacts on regulated parties, why is EPA engaged in a costly and resource-intensive proceeding that will have no impact in the real world?

RESPONSE: The U.S. Supreme Court ruled that GHGs meet the definition of "air pollutant" in the Clean Air Act, and EPA has determined that they may reasonably be anticipated to endanger the public health and welfare. Therefore it is important to ensure that new fossil fuel-fired power plants use the best available technology to limit their emissions of carbon dioxide, the most prevalent greenhouse gas. Because these standards are in line with current industry investment patterns, these standards are not expected to have notable costs and are not projected to impact electricity prices or reliability. However, this rule will ensure that the next generation of fossil fuel-fired power plants in this country will use modern technologies that limit harmful carbon pollution.

21. In 1997, EPA proposed standards to reduce nitrogen oxide (NOx) emissions from utility and industrial steam generating units under CAA section 111(b). For the subpart Da sources covered by the proposed rule, EPA calculated the nationwide increase in annualized costs as well as the cost-effectiveness of the proposed standards, *e.g.*, cost-per-ton of Nox removed.

While EPA also examined the resulting cost of the standards with regard to the price of electricity, EPA stated that "the goal of the economic impact analysis was to estimate the market response to the proposed changes to the existing standards for NOx emissions ... The analysis did not quantitatively address the possibility of changing technology, fuel, or capacity utilization in response to the proposed revisions ..." In addition, while EPA looked at the impact of the rules on electricity prices generally, the Agency specifically examined the price changes on a facility basis, estimating that such costs could be as high as 6 percent. EPA's final rule did not depart from this economic analysis.

The proposed GHG NSPS, however, uses a LCOE to measure the "reasonableness" of the proposed standards. New coal-fired generation with partial CCS is compared to the LCOE of a new nuclear power plant and EPA concludes that "the cost of new coal-fired generation that includes CCS is reasonable today."

a. In the Proposed Rule, EPA claims that case law stretching back 40 years in the D.C. Circuit requires EPA to consider different factors, including that the costs of "the system must be reasonable." But in the Proposed Rule, EPA simply equates the LCOE with what is "reasonable," ignoring past practice where EPA examined facility costs in determining the Best System of Emission Reduction under CAA section 111.

    1. Please provide a detailed explanation of why EPA failed to consider the cost of the proposed rule on individual facilities.
    2. When and on what rationale did EPA determine it would vary from past practice in examining costs when setting BSER under CAA section 111?
    3. Explain why EPA's use of LCOE is superior to the examination of the costs expected to be incurred by individual facilities, in terms of up-front capital costs and the cost per ton of pollution reduced.

RESPONSE: The EPA's economic analysis is based on the expected costs and benefits of the rule, including costs to individual facilities.

There are a number of ways that control costs can be expressed. The Levelized Cost of Electricity (LCOE) is a widely used metric that represents the cost, in dollars per output, of building and operating a generating facility over the entirety of its economic life. Evaluating competitiveness on the basis of LCOE is particularly useful in establishing cost comparisons between generation types with similar operating characteristics, but with different cost and financial characteristics. This measure is consistent with the way costs are presented in DOE/NETL reports evaluating the cost and performance of new fossil fuel-fired EGUs, both with and without CCS.

The EPA is reviewing and considering comments on various metrics that the Agency should consider.

b. Since EPA has proposed that partial CCS is BSER for subpart Da units, please provide the Committee with EPA's estimate of the cost (in$ per ton of C02 avoided and assuming no EOR potential) of partial CCS on a "typical" baseload subpart Da unit, 550 MWe or above, operating at or above 85% capacity. Please include enough detail to determine EPA's assumptions for the costs of capture, transport, sequestration, and monitoring.

RESPONSE: The EPA provided several metrics to show the relative emission profiles, costs, efficiencies, and performance of new fossil fuel-fired electric generating units to

provide context around some of the current investment decisions that utilities and other power producers are contemplating. The analysis is centered on future projections of new power plant deployment from both the EPA and the EIA, which show that the economics support building new natural gas combine cycle technology and other non-emitting sources of electric generation. This analysis incorporated a significant number of side-cases and additional analysis where alternate assumptions regarding future electric demand, natural gas prices, coal prices, benefits of enhanced oil recovery, and carbon uncertainty costs were adjusted. The use of alternative calculations demonstrate that the Agency's conclusions are robust across a wide set of assumptions.

To supplement these findings, the EPA also provided discussion of the levelized cost of electricity and compared the cost and performance of new fossil fuel-fired electric generating technologies, including illustrative benefits of emission reductions. The EPA's Regulatory Impact Assessment provides details of these assessments that relate to your question, including but not limited to:

- **Table 5-5: Technology Cost and Performance**
- **Figure 5-7: Levelized Cost of Electricity, Uncontrolled Coal and Coal with Full and Partial CCS**
- **Table 5-10: Illustrative Emissions Profiles, New Coal and Natural Gas-Fired Generating Units**
- **Table 5-14: 2020 Incremental Benefits of Emission Reductions from Coal-Fired Generation with CCS meeting 1,100 lbs/MWh Relative to New Coal-Fired Generation Without CCS**

22. As you know, power plants are just one of approximately 70 different industrial source categories that EPA regulates under the Clean Air Act. Those categories include nearly every sector of the industrial economy-manufacturing, refineries, steel plants, sewage treatment, fertilizer plants, cement production, and so on. In previous testimony to Congress, Administrator McCarthy refused to rule out new regulations on carbon emissions from these sectors. EPA has an obligation to provide these industries as well as Congress and the public clarity on its plans.

a. Can you tell us if EPA has ruled out greenhouse gas regulations on any of these sectors? If so, which ones, and of the remaining sectors that you do plan to regulate, which ones will be first?
b. What are the implications of this new definition of the "Best System of Emission Reduction"? Might it be used in other rules?
c. Can you assure us that outside groups will not have the power to force the Agency to require CCS in other contexts?

RESPONSE: The EPA is not currently developing national standards to specifically regulate greenhouse gas (GHG) emissions from source categories other than fossil fuel-fired power plants. Were the EPA to propose a New Source Performance Standard that would limit GHG emissions from another source category, the proposal would be based on the best available science and data, including information about all

applicable regulations, to determine what standard represents the Best System of Emissions Reduction as defined by the Clean Air Act. In addition, the EPA would reach out to and engage all interested stakeholders. For example, we are taking comment on whether to directly account for methane from landfills.

23. The GHG NSPS is being sold to the public based on EPA's linking of C02 emissions to potential negative impacts of climate change. Yet the proposed rule states that the GHG NSPS "will result in negligible C02 emission changes...by 2022."

a. How much C02 does EPA estimate that the 111 (b) proposal will prevent between its initial proposal and the 8-year window for review?
b. Has EPA modeled the climate impacts of these anticipated reductions? Why or why not? If so, please provide the assumptions included in this modeling.
c. President Obama's executive order on regulations requires that for any regulation, the benefits must justify the cost. In light of the absence demonstrated benefits associated with this proposal, how do these new standards meet the President's cost-benefit requirement?

RESPONSE: Because these standards are in line with current industry investment patterns, these standards are not expected to have notable quantifiable costs or benefits. However, this rule will ensure that the next generation of fossil fuel-fired power plants in this country will use modern technologies that limit harmful carbon pollution.

24. You testified that EPA's upcoming lll(d) rule will allow states both primacy and great flexibility in determining C02 requirements for the existing units. However, EPA made the same type of statements when it adopted its regional haze regulations and guidelines, and those statements turned out not to be true. I understand 15 states and state agencies have filed a brief with the Supreme Court complaining that EPA in fact has not allowed states flexibility in determining regional haze requirements and instead has overridden state judgments and imposed federal plans in twelve different states. The EPA wants the states' utilities to spend billions of dollars – in addition to the hundreds of millions of dollars that the utilities are othe lwise spending-to install controls that will result in little, if any, improvement in visibility.

With the states having been burned in the regional haze program, why should they believe EPA's statements now about giving states flexibility in C02 programs?

RESPONSE: The EPA has approved over 90 percent of Regional Haze SIPs that were submitted. In a limited number of cases, we had to substitute full or partial federal plans where the state SIP did not fully address the regional haze rule requirements. Only three full FIPs were required (Montana, Hawaii, and Virgin Islands). These three full FIPs were promulgated in cooperation with state/territorial officials because they did not have resources to complete SIPs on their own.

25. In order to bolster the cost feasibility of the NSPS GHG New Plants rule, EPA heavily emphasizes the marketability of C02 to be used in the production of crude oil through enhanced oil recovery (EOR). In fact, the proposed rule and along with the Regulatory Impact Analysis mention 'enhanced oil recovery' or 'EOR' more than 130 times.

However, a 2009 peer-reviewed paper published in Environmental Science & Technology found that EOR as a method of sequestering C02 leads to net increases in C02 emissions. The paper, *Life Cycle Inventory of C02 in an Enhanced Oil Recovery System* found that when oil is produced *"93% of the carbon in petroleum is refined into combustible products ultimately emitted into the atmosphere."* The study concluded that:

> *"The net emissions from* [CCS EOR] *systems are positive meaning that the GHG emissions are larger than the C02 injected and stored in the reservoir."*
>
> *"We calculated that between 3.7 and 4.7 metric tons of C02 are emitted for every metric ton of C02 injected"*

a. Wouldn't this finding-that pairing carbon capture and sequestration with enhanced oil recovery – defeat the fundamental purpose of EPA's proposed rule?
b. The Agency's favorite example of the potential for partial CCS is the Kemper plant in Mississippi and its associated EOR project. In December, Denbury Resources told the Associated Press that without the Kemper plant "they would not be able to produce oil there otherwise." So in EPA's model CCS case, the Kemper plant, the oil would not be produced without Kemper. In this light, wouldn't it be reasonable to assume that the CCS EOR project at Kemper could lead to a net increase in C02 emissions?

RESPONSE: The amount of oil produced through EOR with captured CO2 from new EGU's subject to this proposal would vary by project, but likely would have a negligible impact on total oil consumption – and thus on total CO2 emissions from oil production and consumption. Section 111 of the Clean Air Act authorizes the EPA to promulgate emissions standards for specified source categories, in this case fossil fuel-fired power plants. To be recognized as conducting geologic sequestration under the existing requirements (Subpart RR of the Greenhouse Gas Reporting Program), all facilities, including EOR, must conduct monitoring and reporting to show that the CO2 remains underground.

26. During the first day that President Obama took office, the White House website declared his administration would become "the most open and transparent in history" and the President issued high-profile orders pledging "a new era" and "an unprecedented level of openness" across the entire federal government. The Administration initially estimated the "Social Cost of Carbon" to be $22 per ton. Since then, it has been revised again and yet again. Notice of the most recent estimate came in a little-known rule on microwave ovens issued by the DOE and the cost went to $36. For a decision with such broad implications, there's very little disclosure regarding how these "costs" are being calculated and which

federal officials are participating, and which outside groups are contributing to the inter-agency task force.

a. Who are the specific EPA officials participating in the "social cost of carbon" task force and helping to create these calculations?
b. Does EPA have any separate or independent efforts to set a "Social Cost of Carbon"?
c. Was this factored into the NSPS proposal in any way? Why or why not?

RESPONSE: The EPA works with OMB to ensure that EPA is following guidance in assessing the costs and benefits of their agency actions. The Social Cost of Carbon (SCC) estimates were developed by an interagency working group convened by OMB and the Council of Economic Advisors (CEA). This group worked together to coordinate development of both the 2010 Technical Support Document (TSD) addressing the estimates and the May 2013 technical update and related TSD. EPA officials from the Office of Policy (OP) and the Office of Air and Radiation (OAR) participated in the interagency SCC discussions, including technical staff (economists and climate scientists) from the National Center for Environmental Economics in OP and the Office of Atmospheric Programs in OAR.

On August 25, 2014, GAO released its review of the process used to develop the SCC estimates. It concluded that the working group (1) used consensus-based decision-making, (2) relied on existing academic literature and modeling, and (3) took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available. The report made no recommendations.

In the Regulatory Impact Analysis that accompanied the carbon pollution proposal, the primary conclusion was that the proposal would have no notable costs or benefits because current planned generation would meet the proposed standards even in the absence of the rule. The SCC was only applied in illustrative analyses of the impacts of changes to natural gas prices or limited circumstances where an electric utility would choose to build a coal-fired unit with CCS. The revised estimates for the social cost of carbon – released in November 2013 -- do not impact the RIA's primary conclusion that the proposed Carbon Pollution Standards for New Power Plants will have negligible costs and no quantified benefits, nor do they change the conclusions of the illustrative analyses.

27. Discussions by outside groups of potential uses of Section 111(d) to regulate existing power plants have indicated that this kind of approach in conjunction with other impending EPA deadlines would require that 1) a large number of coal-fired plants be mothballed; and 2) energy demands will have to be reduced through efficiency measures such as making it more expensive for consumers to use appliances at certain time of day.

a. Is EPA open to adopting a proposal that encourages or necessitates price hikes for consumers?
b. What number of power plant closures would EPA consider acceptable?
c. What are the impacts on reliability when EPA considers these rules in the aggregate?

RESPONSE: The Clean Power Plan proposal, which was published in the *Federal Register* on June 18, 2014, provides states with the flexibility to determine how to achieve the reductions in the state goals and to adjust the timing in which reductions are achieved, in order to address key issues such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets. For this proposed rule, the EPA examined the effects of the proposal on reserve margins and reliability planning. Our analysis concludes that the Clean Power Plan is not expected to raise concerns over regional resource adequacy. For more information, please refer to the Regulatory Impact Analysis and to the Technical Support Document titled Resource Adequacy and Reliability Analysis.

For more than 40 years, the Clean Air Act has fostered steady progress in reducing air pollution, allowing Americans to breathe easier and live healthier – all while the economy has more than tripled and an affordable, reliable energy system has continued to operate. We remain committed to maintaining all of those outcomes.

28. What analyses has EPA conducted regarding the practicality and legality of using Section 111(d) of the Clean Air Act to regulate existing power plants?

a. Does EPA believe it has the legal authority to consider potential reductions outside the fence line in setting "achievable" standards? If so please explain in detail. If not, please explain why not.

b. Do you believe EPA has the authority under the Clean Air Act to establish a climate change program for existing power plants, such as the one called for by the NRDC?

RESPONSE: The features of the proposed Clean Power Plan are explained in detail in the preamble to the proposed rule and other materials that the EPA has provided on its website, including a legal memorandum providing background for the legal issues discussed in the preamble. We invite comments on all aspects of the Clean Power Plan proposal.

29. Who will be reviewing the comments submitted to the EPA's rulemaking docket for the NSPS 111(b) proposal?

a. How many EPA employees will review comments submitted? How many hours per week will these employees review comments?
b. Will EPA contract out any of this review to non-EPA employees? If so, please detail exactly what portions of the process and the cost of such review.
c. Will EPA use contractors to draft any Agency responses?
d. Will EPA use computers to sort, collate, or otherwise stream line comments?
e. Does EPA utilize any methodology to identify computer generated or substantially similar comments? How are these types of comments considered when tabulating the number of favorable or unfavorable comments? Do these comments receive the same weight as unique comments?
f. Are there any types of comments the Agency will not consider?

RESPONSE: EPA staff, with support from paid contractors, will review all public comments received, but the EPA does not anticipate using contractors to draft responses to comments. The EPA does use computers in reviewing and responding to comments.

The EPA docket office does differentiate between "Mass Mail Comments" and "Posted Unique Comments." The EPA will consider any comment germane to the proposed regulation, and will develop a final rule considering the content of all comments.

30. Does the Agency believe that it has the legal authority to propose NSPS 111(d) C02 standards for existing EGUs before finalization of its 111 (b) proposal?

a. If so, please provide a detailed legal rationale and any supporting examples or precedent.
b. If not, please provide a detailed legal rationale and any supporting examples or precedent.

RESPONSE: The features of the proposed Clean Power Plan are explained in detail in the preamble to the proposed rule and other materials that the EPA has provided on its website, including a legal memorandum providing background for the legal issues discussed in the preamble. We invite comments on all aspects of the Clean Power Plan proposal.

31. On what date does the Agency believe its 111(b) NSPS proposal was officially proposed? Please provide a detailed legal rationale and any supporting examples or precedent.

RESPONSE: The NSPS published in the *Federal Register* on January 8, 2014.

32. By what date does the Agency believe its 111(b) NSPS proposal must be finalized for purposes of compliance with deadlines included in the Clean Air Act? Please provide a detailed legal rationale and any supporting examples or precedent. .

RESPONSE: The Clean Air Act states the EPA should issue a final rule within one year after publication in the *Federal Register*.

33. Please explain EPA's rational for not including modified sources in the 111(b) proposal. Provide a detailed legal rationale and any supporting examples or precedent.

a. Will the Agency propose a separate rule for modified sources under section 111 or will this rule be combined with the upcoming 111(d) proposal? Provide EPA's legal rationale for this decision.

b. What will be the triggering thresholds for modification? Provide a detailed legal rationale for this decision

c. What will be the effective date for the section 111 modified source rule – p proposal, finalization, or some other date? Provide a detailed legal rationale and any supporting examples or precedent.

RESPONSE: The EPA issued proposed Carbon Pollution Standards for modified or reconstructed power plants on June 2, 2014, and this proposal was published in the Federal Register on June 18, 2014. The proposal would apply to units that meet certain, specific conditions described in the Clean Air Act and implementing regulations for being "modified" or "reconstructed." Under existing regulations, which we did not propose to amend, modification is any physical or operational change to an existing source that increases the source's maximum achievable hourly rate of air pollutant emissions. Under these same regulations, a reconstructed source is a unit that replaces components to such an extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable facility. Because the Clean Air Act defines a new source based on reference to the proposal of applicable standards, sources that commence reconstruction or modification after June 18, 2014 will be subject to the standard of performance for modified and reconstructed units. The proposed emission limits would apply to affected sources upon the effective date of the final regulation.

34. Do you support the principle that EPA should not propose or finalize regulations unless the scientific and technical information relied on is: specifically identified; and publicly available in a manner that is sufficient for independent analysis and substantial reproduction of research results?

RESPONSE: The EPA is committed to transparency with regard to the scientific bases of agency decision making. The science on which regulatory and other decisions are based should be made publicly available consistent with the law.

35. Several important elements of your proposed standard rely heavily or exclusively on the use of the Integrated Planning Model, a proprietary model, instead of public energy models like NEMS.

a. How is this consistent with EPA's Scientific Integrity Policy, which states "the use of nonproprietary data and models are encouraged, when feasible, to increase transparency"?
b. Was it not feasible to rely on a nonproprietary model?
c. Please provide all EPA contracts, grants, and agreements related to the Integrated Planning Model since 2008.

RESPONSE: The EPA's use of the Integrated Planning Model is consistent with the Agency's Scientific Integrity Policy. All of the underlying data, assumptions, modeling parameters, and related information is published on the IPM modeling website and is publicly available. In addition, IPM undergoes periodic formal peer review, which includes separate expert panels for both the model itself and the EPA's key modeling input assumptions. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of the electricity sector that are represented by the model, public interest groups, and other developers of U.S. electricity sector models. The EPA is required to respond to significant comments submitted regarding the inputs used in IPM, its structure, and application. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results.

__The Honorable Marc Veasey__

1. How will EPA enforce the Green House Gas Reporting requirements under subpart RR for EOR operators utilizing Class II wells if they use C02 related to the proposed New Source Performance Standard (NSPS)?

RESPONSE: The compliance and enforcement provisions related to the Greenhouse Gas Reporting Program are set forth at 40 CFR 98.8.

2. If an EOR operator utilizes its current C02 from natural and industrial sources, and C02 captured as a result of the NSPF, will they have to report all EPA GHG requirements under subpart RR?

RESPONSE: The proposed Carbon Pollution Standards rely on the existing EPA requirements that are already in place for monitoring and permitting CO2 injection and geologic sequestration. Under the proposed Carbon Pollution Standards, if a new power plant decides to use CCS to comply with the standard, captured CO2 must be sent to a facility that meets the existing regulatory requirements for monitoring and reporting geologic sequestration. The EPA has an existing permitting framework in place under the Safe Drinking Water Act governing these kinds of projects and has been working closely with states and some facilities in the permitting process. Pilot projects have been permitted under the existing regulatory framework, providing valuable experience and technical information to the EPA and states.

To be recognized as conducting geologic sequestration under the existing requirements (Subpart RR of the Greenhouse Gas Reporting Program), all facilities, including EOR, must conduct monitoring and reporting to show that the CO2 remains underground. For CO2 that is not recognized as being sequestered, EOR facilities can continue to report under the requirements for CO2 injection (Subpart UU of the Greenhouse Gas Reporting Program). The EPA believes that it is appropriate to rely on these same, existing requirements for the proposed new source rule, and will closely evaluate comments that we receive on this issue.

3. What additional requirements would have to be met for a Class VI well as opposed to a Class II well utilizing EOR and who has the authority to make the decision to reclassify a well?

RESPONSE: The regulatory provisions regarding transitioning from UIC Class II to UIC Class VI are set forth at 40 CFR 144.19. The Federal requirements for Class II wells and Class VI wells are set forth at Part 146 Subparts C and H, respectively.

The Honorable Randy Neugebauer

1. I continue to be concerned that EPA isn't truly using a technology that is adequately demonstrated in its rules for new power plants, and continues to cite facilities that aren't even built yet, much less operating full-scale CCS.

In fact, in three of the cases cited by EPA in support of the NSPS rule, the plants are not yet even constructed. In the fourth, the Kemper project in Mississippi, they seem to be capturing the C02 but they aren't injecting it into ground for any kind of storage. This appears to be a "catch and release" approach to CCS, not the full scale demonstration that would be required of future power plants.

But when the Kemper facility is eventually ready to send the captured C02 to an EOR operator, the Kemper has essentially been grandfathered in, and the new rules proposed for EOR operators won't apply in this case. Clearly, this was necessary to keep the Kemper project moving forward, since applying the new EOR rules would likely put Kemper out of business, as EOR would be unlikely to remain a revenue stream for Kemper under the new reporting requirements.

The fact is, this proposal is so radical that even before we finish building the world's very first attempt at a fully equipped CCS power plant, the EPA's own poster child power plant cannot meet the requirements of the rule, and needs to be grandfathered in. With that consideration in mind:

a. How would a future facility like Kemper ever manage to be in compliance with NSPS rules with EOR off the table?

b. Kemper is already heavily subsidized by the federal government – would more government money be required to make this model work without EOR revenue?

c. Why would the EPA design a rule that would essentially prohibit a primary private sector funding source for CCS, the technology they seem determined to require across the board?

RESPONSE: The proposed new source performance standards would be applicable to units that "commence construction" after the date of proposal, January 8, 2014. Since the Kemper facility commenced construction prior to that date, it would be considered an existing source. Therefore, the Kemper facility would not be an affected facility.

For future facilities under the proposed standards, captured CO_2 must be sent to a facility that meets the existing regulatory requirements for monitoring and reporting geologic sequestration. In order to be recognized as conducting geologic sequestration under the existing requirements (Subpart RR of the Greenhouse Gas Reporting Program), all facilities – including EOR – must have monitoring and reporting that shows that the CO_2 is staying underground. For CO_2 that is not recognized as being sequestered, EOR facilities can continue to report under the requirements for CO_2

injection (Subpart UU of the Greenhouse Gas Reporting Program). The EPA believes that it is appropriate to rely on these same, existing requirements for the proposed new source rule, and is closely evaluating comments received on this issue.

The Honorable Cynthia Lummis

1. On December 6, 2013, I sent a letter with then Chairman Stewart and seven other Committee members expressing serious concerns about the EPA's "listening sessions tour," designed, according to the Agency, to "solicit ideas and input from the public and stakeholders about the best Clean Air Act approaches."

The day before our March 12, 2014 hearing, you sent a letter to several members of the Committee stating that the "Administrator has asked that [you] respond on her behalf." Thank you for your detailed response.

Enclosure 2 provides a "List of EPA Meeting with and Outreach to Stakeholders in Select States" represented by those of us who sent the original letter. With regard to this table, please specify for each meeting noted:

a. The physical location of the meeting.
b. Whether the meeting was open to the public.
c. How and when were members of the public and stakeholders notified of the meeting.
d. Whether the meeting was transcribed or recorded.

RESPONSE: Locations, attendees, and other details of the meetings in question varied, in part depending on whether the meetings were initiated by the EPA or by others.

2. During our hearing, I asked you a question regarding this issue, but wanted to follow up in writing. As I noted, EPA's current permitting guidance for GHG emissions requires all units that need a PSD permit for GHG emissions to evaluate CCS. In fact, this guidance classifies CCS as an "add-on pollution control technology" that is "available."

a. Why does EPA guidance require a CCS analysis for new natural gas-fired units, including power plants as well as boilers and heaters within manufacturing plants?
b. Please outline the specific conditions under which EPA would require CCS for either natural gas fired utility units or non-utility boilers and heaters? If EPA would not require the use of the CCS for these sources, why is the Agency requiring this analysis?
c. If EPA does not believe as a general matter that CCS should be required for these natural gas-fired units, why hasn't EPA issued a memorandum to states noting that this analysis is not required as a general matter for these combustion sources?
d. Has EPA considered the regulatory uncertainty and permitting delays that result from declaring in your PSD guidance that CCS is "available" and for requiring a CCS analysis on natural gas-fired sources, including manufacturing combustion devices?

e. Has EPA undertaken comprehensive modeling of the impacts this regulatory uncertainty has had on job creation given that it may delay the construction of manufacturing plants?

RESPONSE: Permitting under the Prevention of Significant Deterioration (PSD) program requires a source-specific analysis of all "available" control options for the pollutant under evaluation. To satisfy the Clean Air Act requirement of best available control technology (BACT), the BACT analysis should focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question. Since CCS is a demonstrated technology that achieves a high level of control of carbon dioxide, it is reasonable to expect that a GHG BACT analysis for certain types of sources would consider CCS as an available technology. To disregard an available technology, such as CCS, in the BACT review process would be counter to the principles laid out in the Clean Air Act definition of BACT and in the historical policies of the EPA and other permitting authorities, and could jeopardize the defensibility of the final permit, if challenged.

The Clean Air Act and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case, site-specific basis, and the permitting authority must evaluate the amount of emissions reductions that each available and technically feasible control technology would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. A memorandum by EPA notifying states that a particular class or category of source need not evaluate an available control option such as CCS in this context would improperly prejudge the outcome of the analysis that is required by statute to be conducted on a case-by-case basis for each individual source seeking a permit.

Contrary to your statement, the EPA's permitting guidance does not require an assessment of CCS for all types of sources seeking a PSD permit for GHG emissions. The EPA views the availability of CCS as limited to certain types of sources. The guidance states, in relevant part:

> ***For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis.***

3. EPA is also requiring CCS analyses for LNG facilities. Further, the EPA Environmental Appeals Board (EAB) appears to be reviewing a challenge by the Sierra Club on whether CCS should be required at LNG facilities. What effect does this regulatory unceliainty created by the Agency have in potentially delaying the much needed export of natural gas?

RESPONSE: The EPA is not aware of a PSD permit for an LNG facility that is under EAB review.

BACT is a case-by-case assessment of all control technologies that are available for reducing pollution from a source. Because CCS is a demonstrated technology that achieves a high level of control of carbon dioxide, it is reasonable to expect that a GHG BACT analysis for certain types of sources (such as LNG sources) would consider CCS as an available technology. To disregard an available technology, such as CCS, in the BACT review process would be counter to the principles laid out in the CAA definition of BACT and in the historical policies of the EPA and other permitting authorities, and could jeopardize the defensibility of the final permit, if challenged.

4. As you know, the President's budget includes $25 million to fund CCS for natural gas projects. If one of these projects becomes operational, would that be sufficient for EPA to begin requiring CCS as part of the NSPS or the PSD permitting process? What is the goal of these efforts? Will EPA be working with DOE on these projects?

RESPONSE: As outlined in the proposed Carbon Pollution Standards for new fossil fuel-fired power plant, determining BSER involves consideration of a number of factors. The successful operation of a natural gas-fired power plant utilizing CCS would be considered in such a BSER determination, but it would not necessarily result in CCS being found to be BSER. Similarly, BACT determinations for PSD permitting are done on a case-by-case basis, and while the successful operation of a natural gas-fired power plant utilizing CCS would be considered in such an analysis, it would not necessarily result in CCS being required for each permitted facility of the same type.

5. Please identify all:

a. Post-combustion coal projects EPA has cited or is aware of.

RESPONSE: The EPA has primarily referenced and discussed the following projects: Searless Valley Mineral Soda Ash (Trona, CA); AES – Warrior Run (Cumberland, MD); AES – Shady Point (Panama, OK); AEP Mountaineer (New Haven, WV); Southern Company Plant Barry (Mobile, AL); SaskPower Boundary Dam (Estevan, SK, Canada); and NRG Petra Nova WA Parish Plant (Houston, TX). The EPA is also aware of the Ferrybridge capture project (West Yorkshire, UK).

b. Post-combustion natural gas projects EPA has cited or is aware of.

RESPONSE: The EPA is only aware of one natural gas power plant that has demonstrated post-combustion capture: the Bellingham NGCC Power Plant (Bellingham, MA).

c. Pre-combustion CCS projects currently capturing and storing C02 at coal power plants that EPA has cited or is aware of.

RESPONSE: The EPA is aware that the following gasification facilities are currently utilizing coal (or petcoke) and capturing and storing CO_2: Dakota Gasification Company Great Plains Synfuels (Beulah, ND) – utilizes lignite coal; Coffeyville Gasification Plant (Coffeyville, KS) – utilizes petcoke.

d. Pre-combustion CCS projects currently capturing and storing C02 at natural gas power plants that EPA has cited or is aware of.

RESPONSE: The EPA is unaware of any pre-combustion CCS projects at natural gas power plants that are capturing and storing CO_2.

e. CCS power plant projects proposed or under construction that EPA has cited or is aware of.

RESPONSE: The EPA has primarily discussed and cited the following power plants that are proposed or under construction that are designed to use CCS: SaskPower Boundary Dam (under construction; Estevan, SK, Canada) – post-combustion, coal-fired; NRG Petra Nova WA Parish (under construction; Houston, TX) – post-combustion, coal-fired; Southern Company Kemper County Energy Facility (under construction; Kemper County, MS) – pre-combustion, IGCC utilizing lignite; Summit Power Texas Clean Energy Project (planned, Odessa, TX) – pre-combustion, IGCC utilizing coal; Hydrogen Energy California (planned, Kern County, CA) – pre-combustion, IGCC utilizing coal and petcoke.

f. Other non-power generation CCS projects currently capturing and storing C02 at the same scale that would be required in the power generation context--at least 1,000,000 tons C02 per year. How long has any such project been continuously capturing, injecting, and monitoring at this scale? What legal and regulatory systems are any such projects operating under?

RESPONSE: The Dakota Gasification Company – Great Plains Synfuels facility in Beulah, ND has captured over 2,000, 000 tons/year on average since 2000. The captured CO_2 is transported via pipeline to the Weyburn oil fields in Canada for use in EOR operations and for CO_2 storage. The project has no legal or regulatory obligation to capture CO_2. Note also that the Coffeyville Gasification Plant (Coffeyville, KS) captures CO_2 at rates of > 1,000,000 tons per year and in 2013 began utilizing 650,000 tons/year for EOR/CO_2 storage.

The Honorable Joe Kennedy

1. It is my understanding that there are some industries, such as the chemical industry and The cement industry that can utilize CO_2 in their production process. It can also be used as a feedstock for algae and other alternative fuels. Technology already exists using CO_2 for enhanced oil recovery (EOR) purposes. CO_2 emissions pose an incredible risk to our environment and economy. Finding a beneficial way to utilize the CO_2 we are already emitting would accomplish multiple goals at the same time -protecting the environment and the economy while continuing to harness an all-of-the-above energy strategy. How does the proposed rule for carbon pollution standards from new power plants take into consideration and encourage the beneficial use of CO_2? Are there any activities beyond EOR, including those in conjunction with DOE, by the EPA to encourage the beneficial use and reuse of CO_2?

RESPONSE: The EPA agrees that there are types of CO_2 storage technologies other than geologic sequestration that are under development. In the proposed Carbon Pollution Standards for New Power Plants, the EPA sought comment on the use of CO_2 storage technologies other than geologic sequestration, and the EPA will review and consider the comments received on this issue.

Appendix II

ADDITIONAL MATERIAL FOR THE RECORD

ARTICLE SUBMITTED BY REPRESENTATIVE CYNTHIA LUMMIS

The New York Times | http://nyti.ms/1i1vFJW

ENERGY & ENVIRONMENT

Coal to the Rescue, but Maybe Not Next Winter

By MATTHEW L. WALD MARCH 10, 2014

COLUMBUS, Ohio — When the temperature here dropped into the teens this winter, ice formed on the inside of Ernestine J. Cundiff's windows in the drafty 50-year-old apartment building where she lives. At 81, with diabetes, poor circulation in her legs and both shoulders damaged in separate falls last year, Ms. Cundiff said wearing leggings and fur-lined slippers was not enough to keep her warm, so she took to using an electric space heater in her bedroom.

Then came the electric bill, $96.75 in January, up about 50 percent from the previous month. That was in addition to a gas bill of $153.44, up from $106.12 the month before. "When I opened the bills, I thought I was going to have another heart attack," said Ms. Cundiff, whose only income is the $1,226 a month she receives from Social Security.

Like many other people this winter, Ms. Cundiff turned to a community service organization. Impact Community Action, a Columbus agency, enrolled her in a state program that holds energy bills to 6 percent of a person's income. Regina Clemons, the director of emergency assistance at Impact, said the group was on track to sign up 9,000 to 10,000 people this winter, compared with about 8,000 last winter.

"We find people who have never ever walked into a community action agency before, looking for help," said Carmen Allen, the community outreach coordinator.

As the end of the harshest winter in recent memory approaches, the bill is coming due for millions of consumers who are not only using more electricity and natural gas but also paying more for whatever they use. And there might not be relief in future winters, as the coal-fired power plants that utilities have relied on to meet the surge in demand are shuttered for environmental reasons.

The sticker shock has been particularly acute in the Northeast, where natural gas supplies have been constrained. But it has spread to other regions of the country, including the Midwest, where utilities have had to draw on more expensive reserves to meet the demand.

In Pennsylvania, Attorney General Kathleen G. Kane said her office had been flooded with complaints from consumers whose utility bills had soared, in some cases tripling. In Rhode Island, the utility National Grid received permission for a 12.1 percent electricity rate increase in January, nearly all of it because of higher prices for the gas used to make electricity.

In New York, Con Edison increased the price of each kilowatt-hour about 16 percent this month compared to last year. And in Ohio, energy retailers will demand higher prices from customers like Ms. Cundiff when annual contracts are renewed.

Underlying the growing concern among consumers and regulators is a second phenomenon that could lead to even bigger price increases: Scores of old coal-fired power plants in the Midwest will close in the next year or so because of federal pollution rules intended to cut emissions of mercury, chlorine and other toxic pollutants. Still others could close because of a separate rule to prevent the damage that cooling water systems inflict on marine life.

For utilities, another frigid winter like this one could lead to a squeeze in supply, making it harder — and much more expensive — to supply power to consumers during periods of peak demand.

Senator Lisa Murkowski of Alaska, the ranking Republican on the Senate Energy Committee, told utility regulators in a speech on Feb. 11 that the recent frigid weather had provided "a glimpse of the challenge that lies ahead." American Electric Power, which serves Columbus and a vast area of the Midwest, was running 89 percent of the coal plants that it must retire next year, she said.

"That raises a very serious question," she said. "What happens when that capacity is gone?"

The coal plants are dirty, and expensive compared to natural gas at summertime prices. But coal is far less prone to price jumps or to shortages, and in a cold snap, it looks like a bargain. Without the coal plants, experts agree, prices in the peak periods of winter and summer will be higher, so future periods of cold weather may be even harder on electric bills.

"We are seeing unprecedented amounts of coal units retiring," said Andrew L. Ott, a senior vice president at PJM Interconnection, the grid operator that covers Pennsylvania, New Jersey and Maryland and has expanded into West Virginia, Ohio and adjacent areas.

"No doubt this industry is in a massive transition," he said, adding that the change would be accompanied by more price volatility.

PJM recently set a peak record for winter energy use of about 140,000 megawatts. Its summer record is 168,000 megawatts. Plants that use coal, with a combined capacity of about 12,000 megawatts, are retiring. Enough capacity is available, and new gas-fired units are being built, but while gas production has kept up with consumption, pipeline capacity has not.

In some cases, the Environmental Protection Agency has reduced the disruption caused by retirements by delaying deadlines, to give utilities more time to comply with its rules or to get alternate arrangements in place. But American Electric Power executives say that will not be the case this time, because even with a reprieve from Washington, citizens could bring lawsuits under the Clean Air Act that would force the closures.

What's more, many plants are far along the path to retirement. At Muskingum River, a five-boiler coal plant in Beverly, Ohio, about 100 miles southeast of Columbus, three of the units ran during the so-called polar vortex, supplying power to meet the demand.

But three-quarters of the 400 or so employees the plant had two years ago are gone, and two of the five units need half-million-dollar repairs to run again, an expensive proposition for a plant that is scheduled to close and runs only intermittently.

American Electric Power has stopped hiring at other plants that are scheduled to remain in service, to make space for employees who would like to transfer. Units 1 and 2 at Muskingum River, commissioned in the early 1950s, cannot run anymore because they both need a new lining in the floor of their boilers, at a cost of about $500,000 each, and there would be no time to recoup the investment. Unit 5, the youngest, commissioned in 1968, was a candidate for continued use, but it would need upgrades to reduce pollution that would cost hundreds of millions of dollars. Lately the plant has run only on very hot or very cold days.

The plants set to be closed will not be replaced by newer, cleaner coal plants, and a number of new gas plants are planned or under construction. The average price of natural gas is too low to let coal compete, and new rules loom for carbon dioxide emissions from new coal plants. And it is not only coal that is disappearing from the mix. Nuclear energy is, as well. Last year the energy company Dominion closed its Kewaunee reactor in Wisconsin, which had been running smoothly and without opposition but could not produce power at a competitive rate in the Midwest electricity market. Another energy supplier, Entergy, announced that it would close Vermont Yankee, a nuclear power station in Vernon, Vt., because the cost of production was higher than the market rate for power. In both cases, the main challenge was natural gas, which has remained cheap apart from the recent price surges.

Marvin Fertel, the president of the Nuclear Energy Institute, the industry's trade association, told Wall Street analysts on Feb. 13 that the gas crunch illustrated the need for diverse sources of energy.

"Risks are lower with diverse portfolios," he said, but the competitive market does not reward diversity. Nor does it reward a coal plant with a supply of fuel that could last weeks in a pile nearby, or a reactor with 18 to 24 months of fuel in its core, he said.

At the Muskingum River coal plant, there was resignation and uncertainty. Muskingum will be "dispositioned," in the new jargon, while other plants, with more antipollution equipment, have been designated "keepers." The plant opened six years before Craig Douglass, 54, was born, and Mr. Douglass, an outage coordinator who has worked there for 33 years, said of the people who built it, "I don't think they ever imagined they'd be running that long."

Mr. Douglass is going to a "keeper" plant. Others are retiring. In the control room one recent afternoon, there was an odd mix of crisp, modern computer screens and control panels that looked as if they had been borrowed from a 1950s science fiction film. Michael Stehly, 55, a supervisor, clearly did not want to operate either.

"I might be the guard at the gate," he said, "who lets the scrap metal trucks in and out."

A version of this article appears in print on March 11, 2014, on page B1 of the New York edition with the headline: Coal to the Rescue, This Time.

LETTER SUBMITTED BY REPRESENTATIVE DAVID SCHWEIKERT

American Water Works Association

Dedicated to the World's Most Important Resource

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March 12, 2014

The Honorable Lamar Smith, Chair

The Honorable Eddie Bernice Johnson, Ranking Member

House Committee on Science, Space, and Technology

Dear Mr. Smith and Ms. Johnson,

The American Water Works Association requests that this letter and attachment be entered into the record of the Committee's hearing today on carbon capture and storage (CCS). While the American Water Works Association has not taken a position at this time on whether EPA should eventually encourage or even mandate CCS as a method for controlling greenhouse gas emissions, we believe very strongly that underground sources of drinking water (USDW) must be protected from CCS activities. CCS has not been implemented anywhere for large volumes of CO_2 injection. Therefore, it should be considered an experimental technology and could pose significant risks to drinking water sources if rushed prematurely to commercial scale.

Although EPA's Class VI rules promulgated under the Safe Drinking Water Act's Underground Injection Control program address many of the potential causes of drinking water contamination, AWWA continues to be concerned with some of the rule's provisions that were included over the strong objections of the drinking water community. For example, the "injection depth waiver" process allowed by the Class VI rule has many limitations that could result in degradation of USDW.

Essentially, the drinking water community and the citizens it serves are being asked to "trust" that geologic sequestration technology will work as promised, even though there is very little if any experience with this technology at a large scale. Although several DOE-sponsored projects have been successful, these projects have been too small and few in number to provide confidence that carbon sequestration projects will be protective of USDW at large injection volumes. Moreover, it is likely that many areas are simply unsuitable for CCS based on geology or other factors.

We are concerned that the risk of unintended consequences from geologic sequestration is high, and such consequences could be difficult or impossible to correct after contamination of USDW. It is quite possible that CCS could make large amounts of USDW permanently unsuitable for use as community water supply.

These points are not to suggest that CCS cannot or should not go forward. But we believe the technology has not been proven and is, in fact, not well understood at the scale anticipated. Nor, we must add, is

EPA's regulatory system for CCS robust and mature since, to the best of our knowledge, not a single Class VI UIC permit has been issued.

AWWA remains committed to working with the EPA, DOE, and interested groups to address the impacts and causes of climate change. However, we strongly believe that it makes no sense to protect our air at the expense of our water. We need both clean air and clean water. Therefore, we ask that you ensure the promised benefits of CCS are carefully weighed against its potential costs and the risks of unintended consequences before the nation makes an irrevocable commitment to CCS.

We would be happy to meet with you at any time or answer any questions you may have concerning our views and concerns on this important issue.

Respectfully,

Tom Curtis

Thomas W. Curtis
Deputy Executive Director
American Water Works Association

LETTER SUBMITTED BY REPRESENTATIVE RALPH HALL

E. SCOTT PRUITT
ATTORNEY GENERAL OF OKLAHOMA

February 28, 2014

VIA CERTIFIED MAIL & E-MAIL

The Hon. Regina A. McCarthy
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Re: Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells

Comments from the Attorneys General of the States of Oklahoma, Alabama, Michigan, Nebraska, South Carolina, Texas and Wyoming

Dear Administrator McCarthy:

We are writing to express our concern over the Environmental Protection Agency's (EPA) Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells (Draft Guidance), issued in December 2013. The Draft Guidance proceeds from an inaccurate understanding of the authority of a Class VI regulator with respect to Class II wells and therefore unlawfully interferes with the authority granted to States under the UIC Program. We respectfully request that EPA resolve this fundamental flaw to protect vital sectors of our economy and preserve the well-being of the citizens and businesses of our States.

The Safe Drinking Water Act's (SDWA) UIC Program is intended to protect subsurface supplies of drinking water from the drilling and use of underground wells for various industrial activities. Under this program, oil and gas wells are classified as "Class II" wells, and, pursuant to the structure of the UIC Program and primacy agreements with EPA, our states – and not EPA

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– serve as the primary regulators of Class II wells. Recently, EPA created a new class of wells under the UIC Program, known as "Class VI" wells, for the underground injection and storage of carbon dioxide (CO_2), primarily in connection with prospective carbon capture and storage (CCS) operations. *See* 75 Fed. Reg. 77230 *et seq.* (Dec. 1, 2010). *See also* 75 Fed. Reg. 75060 (Dec. 1, 2010).

Notwithstanding this new class of wells intended to accommodate the underground injection of CO_2, many oil and gas producers operating Class II wells have been injecting CO_2 for the past 40 years to manipulate well pressure and enhance the recovery of oil and gas. This process, commonly referred to as enhanced oil recovery (EOR), has been used in more than 10,000 wells, about 7,000 of which are currently active. EOR represents a critically important part of our states' and our country's energy infrastructure and plays an essential role in our nation's economic stability and energy security.

The Draft Guidance, arising from EPA's newly-created Class VI wells, is directed at the interplay between Class II and Class VI wells as it relates to underground CO_2 injection. But rather than provide clarity and avoid interfering with the production of oil and gas via EOR – which, again, we emphasize has been occurring for the past several decades without increased risk to drinking water and other subsurface assets – the Draft Guidance has introduced confusion and uncertainty into the oil and gas industry and failed to resolve the business community's outstanding issues with the UIC Program.

Specifically, the Draft Guidance indicates that a regulator in an EPA regional office overseeing Class VI wells (*i.e.*, the Class VI Director) has the authority to determine whether a Class II well at which EOR operations are occurring must "transition" to a Class VI well. This flies in the face of prevailing industry practice, as well as common sense. It also violates current law and the proper division of authority between EPA and states under SDWA.

As part of its rulemaking in 2010 creating the Class VI well category, EPA articulated a series of factors by which a Class II well with EOR operations could be reclassified a Class VI well, presumably to perform CCS-type operations instead. 40 C.F.R. § 144.19. This included such criteria as an increase in reservoir pressure within the injection zone, an increase in CO_2 injection rates, suitability of the Class II area of review delineation, the owner's or operator's plan for recovery of CO_2 at the cessation of injection, the source and properties of injected CO_2, and any additional site specific factors as determined by the regulator. *Id.* Many Class II permit holders communicated to EPA that these criteria were too vague and could lead to the reclassification of wells in which CCS was neither intended nor actually occurring. In response, EPA prepared and issued the Draft Guidance in December 2013.

The Draft Guidance correctly states that while CO_2 is stored underground during EOR operations in a Class II well, this alone does not require the transition of the Class II well into a Class VI well. To the contrary, EPA has plainly stated that EOR operations at a Class II well are not to be affected by the Class VI rule:

> Traditional ER projects are not impacted by this rulemaking and will continue operating under Class II permitting requirements. EPA recognizes that there may be some CO_2 trapped in the subsurface at these operations; however, if there is no increased risk to [underground sources of drinking water (USDW)], then these operations would continue to be permitted under Class II.

75 Fed. Reg., at 77245. The Draft Guidance properly reiterates this point, stating "[t]raditional EOR projects are not affected by the Class VI rulemaking and will continue to be permitted under Class II requirements." Draft Guidance, at 1.

But then the Draft Guidance goes on to describe scenarios in which a Class II well with EOR operations would need to be reclassified as a Class VI well, based on the unchecked increase in subsurface pressures caused by the injection of CO_2. This is blatantly inconsistent with prevailing practices in the oil and gas industry and contrary to law.

Under the UIC Program, our states are vested with authority to permit Class II wells with EOR for purposes of enabling the production of oil. As part of this, the state-level Class II Director reviews maximum and average injection pressures and other information to ensure that CO_2 injection will "not result in the movement of fluids into a USDW so as to create a significant health risk." Draft Guidace, at A-4-A-5. Class II regulations specify limits on injection pressures to prevent the movement of injection or formation fluids into a USDW or the fracturing of the confining zone. *Id.* at A-8. *See also* 40 C.F.R. § 146.23(a). The Class II framework is thus wholly competent to prevent unchecked increases in subsurface pressures during EOR operations and other traditional oil and gas production methods. The scenario described by EPA as a trigger for reclassification simply is not reflective of real world operating conditions.

The actual circumstance under which reclassification would occur, also described in the Draft Guidance, is where a Class II operator changes the primary purpose of the well from the production of oil to the maximal underground storage of CO_2 and, in so doing, changes its operations in such a way as to transcend the confines of the Class II regulatory structure and create an "increased risk to USDWs compared to traditional Class II operations using carbon dioxide." Draft Guidance, at ii. Importantly, this is not so easily done. A Class II permit holder cannot change from EOR to maximal CO_2 storage without accounting for numerous other interests and legal and business considerations. For example, its contractual obligations with land owners and/or subsurface rights holders would most likely need to be altered, if not renegotiated, to accommodate such a transition. Similarly, state laws intended to enable oil and gas production can, in certain circumstances, interfere or even prohibit the use of oil and gas wells for maximal CO_2 storage if future production would be inhibited.

But regardless, the Draft Guidance further complicates and confuses the situation by erroneously implying that the Class VI Director can, on his or her own volition, preempt the Class II Director and require the Class II permit holder to file for reclassification under ClassVI. This is not lawful. Allowing the Class VI Director to "second guess" the Class II Director and intervene seemingly on a whim violates EPA's own rules regarding state primacy and flagrantly impinges upon state authority. EPA cannot revoke a state's primacy unless it can show a failure to comply with applicable requirements. 40 C.F.R. § 145.34(b). These requirements prescribe a series of detailed steps EPA must follow in order to do so, including providing adequate notice to the state and allowing the state sufficient time to take corrective action.

Thus the Draft Guidance, in overtly implying that the Class VI Director is empowered to act unilaterally within an industry in which he or she lacks requisite experience – thereby exposing a Class II permit holder to the seemingly unbounded risk of being ordered, absent any specific criteria, to apply for reclassification – is utterly and entirely beyond the bounds of EPA authority and carries the very real possibility of doing harm to our nation's energy infrastructure. Moving beyond the confines of a traditional Class II well with EOR operations to maximal CO_2 storage is not easily nor quickly done and implicates significant economic and other business considerations. Allowing the Class VI Regulator to intervene seemingly without basis adds an unconscionable level of uncertainty and risk to a mature area of industrial activity already well and thoroughly regulated.

For the foregoing reasons, we respectfully request you take immediate action to rectify this situation as the Draft Guidance is finalized and, additionally, through any other rulemakings as may be necessary under the UIC Program to eliminate this uncertainty and ensure strict adherence to applicable law.

Sincerely,

Scott Pruitt

E. Scott Pruitt
Oklahoma Attorney General

Luther Strange

Luther Strange
Alabama Attorney General

Greg Abbott

Greg Abbott
Texas Attorney General

Bill Schuette

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ARTICLE SUBMITTED BY REPRESENTATIVE RALPH HALL

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Daily News

Sierra Club Opposes CCS Coal Utility EPA Cites In Climate NSPS Defense

Posted: March 10, 2014

The Sierra Club is opposing a pending coal-fired power plant in Mississippi that will be among the first to use carbon capture and sequestration (CCS) on a large scale, even though the group backs EPA's proposed utility climate rule that justifies a CCS mandate for new coal plants based in part on the Mississippi plant -- a position critics say is "tortured."

In response, a source with the Sierra Club headquarters says the group's opposition to Southern Company's almost-complete Kemper coal utility in Mississippi "is independent of the CCS question. . . . We support CCS as a requirement for construction of new coal-fired power plants. . . . When we talk about whether we support a plant, we look at the individual situation," the source says, noting that few coal plants escape opposition from environmental groups.

But one industry source says, "An organization that is opposed to all coal plants may not really be in favor of carbon capture. . . . Of course the Sierra Club has a tortured position. They're against coal."

The group's backing of CCS as a mandate for newly constructed coal plants in EPA's pending carbon dioxide (CO2) new source performance standard (NSPS) would "presume they would advocate the use of fossil fuels, and Sierra Club doesn't. I assume at some point their donor base points that out to them," the source says.

A source with environmental group Clean Air Task Force (CATF) also questions Sierra Club's battle against the Kemper facility, saying that the opposition appears to focus more on the capital costs and its impact on electricity rates, rather than more typical concerns about the plant's environmental impacts.

The fight over the Kemper plant highlights several ongoing key issues in the debate over regulating the utility sector's CO2 emissions: the scope of the industry's emissions, the need to promote power sector projects to deploy CCS technology, and hurdles to completing construction of utilities with CCS.

The fate of CCS projects at utilities is central to EPA's pending NSPS for future power plants, which would require partial CCS at new coal-fired plants. Critics of the proposed rule say this represents a "war on coal" that would effectively ban new coal utility construction because CCS is cost-prohibitive and not in wide use.

EPA has defended the CCS mandate, which is based in part on Kemper and a handful of other pending coal utility CCS projects as showing it is viable for new sources. The rule cites other CCS projects, including Summit Power's Texas Clean Energy Project -- though that may be in doubt after its power purchase agreement expired in January.

CCS Project

Southern Company, which is developing the 582-megawatt Kemper County Energy Facility that will capture 65 percent of its CO2, has urged EPA not to rely on the plant to support its proposed CCS mandate. The project has received significant funding from the Department of Energy (DOE), and opponents of the NSPS claim a 2005 energy law prohibits EPA from citing DOE-funded projects to justify CCS regulatory mandates, though EPA in a recent data notice rejected that claim.

The agency first proposed the climate NSPS in 2012 but in response to comments withdrew it and re-proposed it in January. During the lag time, EPA increased its reliance on Kemper, noting in the new proposal that since April 2012 the project has made "significant progress" and is now "over 75 percent complete."

Sierra Club backs EPA's NSPS and its CCS mandate, even as it pursues a challenge to the Kemper facility, prompting criticisms from other environmentalists and industry sources for a "tortured" position.

Sierra Club's Mississippi chapter has been working since 2009 to defeat Kemper, citing its capital costs of more than $5 billion, the impact on ratepayers, and concerns about non-GHG emissions from the plant.

But the source with the CATF -- a vocal supporter of both CCS and Kemper -- says Sierra Club appears to be opposing the project for the wrong reasons, such as costs rather than environmental impacts. The source "is prepared to concede that this is an expensive plant," because with $5 billion in costs and overruns it is the most expensive capital project ever undertaken in the state of Mississippi. However, the source believes the project is vital to advancing CCS, "a technology that is essential to avoiding the worst aspects of climate change."

Many of Sierra Club's attacks on Kemper "focus exclusively on costs and not on the environment. . . . Last I checked that wasn't the central focus of the Sierra Club's mission: saving ratepayer money in Mississippi," the source says.

The industry source concurs with that response, saying, "This is the only time in the history of the planet that Sierra Club has demonstrated any concern with what the ratepayers need to pay. To say it is a smokescreen is way too kind. They have never complained about the rate impact of a wind farm."

However, the Congressional Research Service in a Feb. 10 report on DOE-funded CCS projects notes, "Cost overruns at the Kemper plant, however, have raised questions over the relative value of environmental benefits due to CCS technology compared to construction costs of the facility and its effect on ratepayers."

Sources also point out that Sierra Club's position is somewhat the inverse to Kemper's developer, Southern Company, which in public statements last fall urged EPA not to cite it as a basis for the NSPS rule. For example, Southern Company's gasification manager, Randall Rush, called Kemper a "specific project in a specific place that meets the needs of the state of Mississippi. . . . It doesn't seem to make any sense to me to be a basis for an environmental standard on a national basis."

EPA Proposal

In order to mandate CCS in the NSPS rule being developed under section 111(b) of the Clean Air Act, EPA must show that the technology is commercially available and adequately demonstrated. It also must show that it is not relying solely on Kemper and the other CCS projects it cites in the proposal because they are receiving DOE funding.

In the proposal, EPA cites Kemper as one of the main examples, and lauds its progress, saying, "Performance testing is expected to commence in late 2013 and the facility is expected to be fully operational in 2014."

The Kemper County energy facility will use Southern Company's Transport Integrated Gasification (TRIG) technology, developed with significant DOE funding that will allow it to gasify lower grade lignite coal and then capture the carbon and pipe it to nearby oil fields. GHG and criteria emissions from the plant will be comparable to a natural gas facility.

A second industry source -- who says EPA should not rely on Kemper and other DOE-funded projects to justify he NSPS -- says these projects "fall short of what EPA needs to show for CCS to be adequately demonstrated," but they are nonetheless important for the further development of CCS technologies. "CCS needs more public-private partnerships focused on advancing the technology and more support and incentives for new projects. CCS just isn't ready to respond to a regulatory mandate from EPA, and the mandate alone won't make it ready."

Southern Company in a Feb. 26 statement to *Inside EPA* said, "The proposed standards for new coal-fired power plants appear to be based on CCS and the anticipated performance of the Kemper County energy facility." But the company added that, "Because the unique characteristics that make the project the right choice for Mississippi cannot be consistently replicated on a national level, the Kemper county energy facility should not serve as a primary basis for new emissions standards impacting all new coal-fired power plants."

The CATF source says the company's and Sierra Club's positions on Kemper and the NSPS "are useful in the broader debate" over the viability of CCS. "Southern is saying we built this plant, and it's great, but it doesn't provide that CCS is viable" in the EPA rule. "Then Sierra Club opposes the plant because they think it's horrible but they think the rule is great. . . . We think it should be built and we think including CCS in the NSPS is viable."

But the Sierra Club headquarters source disagrees, saying, "We evaluate power plant proposals on a plant-by-plant basis in conjunction with local chapters. And a decision was made that we did not support the Kemper proposal. We are not opposing it because it's CCS and we obviously are willing to oppose plants that include CCS as a technology."

The group also believes Kemper serves as proof that it is "reasonable for EPA to conclude it is technologically possible to" include CCS in the NSPS, the source says. But is it also "important to point out that Kemper is not a normal CCS plant. They are trying to prove their own gasification technology," for one.

Further, the group points out, the plant has no regulatory requirement to actually capture any of its carbon emissions if the CCS does not work or other problems occur, as consulting firm Element VI noted in an analysis last year.

Environmentalists' Concerns

A source with Sierra Club's Mississippi chapter details several environmental problems with the plant, including that the particulate matter and mercury controls are not as stringent as they could be, and that it includes a 45-square-mile lignite strip mine. Further, the facility's certificate of need is again before the state supreme court; the state has issued questionable bonds to help finance the project; and residents' taxes have increased, the source says.

"This has definitely been clouded with what I would consider to be a lot of eyebrow-raising events," the source says, the upshot of which shows that Kemper is "dirty, it's expensive and it's unnecessary." The source alleges Kemper is not about CCS but rather a way for the company to win DOE financing for its TRIG technology. Because Mississippi is a regulated state, "For every dollar they spend, they get to collect a 10 to 12 percent rate of return by law."

The $5.25 billion in costs for the project will be most keenly felt by its 189,000 customers in one of the poorest states in the country, many of whom live on fixed incomes, the source adds.

But the second industry source stresses the importance of Kemper as "the world's only coal plant of any meaningful size with CCS that's currently under construction," the source says. "Coal use is growing around the world, particularly in Asia, and it's quite possible that if you don't have projects like Kemper today, then all this overseas coal gets built in the years ahead without CCS and, as a result, without any constraint on their CO2 emissions."

This source faults Sierra Club's Kemper opposition as "very clear in terms of what they don't like but not clear in terms of what they do. You might think you can just get rid of coal, but a quick look around the world shows coal use going up, no matter what happens in the United States. This is why other environmental groups have recognized CCS as a vital part of any effort to address climate change. Sierra Club is basically on its own." -- *Dawn Reeves (dreeves@iwpnews.com)*

Related News: Climate Policy Watch

2463830

STUDY SUBMITTED BY REPRESENTATIVE RANDY NEUGEBAUER

The Heritage Foundation

ISSUE BRIEF

No. 4158 | MARCH 04, 2014

EPA's Climate Regulations Will Harm American Manufacturing

Nicolas Loris and Filip Jolevski

The Environmental Protection Agency's (EPA) forthcoming climate change regulations for new and existing electricity generating units have been appropriately labeled the "war on coal,"[1] because the proposed limits for carbon dioxide emissions would essentially prohibit the construction of new coal-fired power plants and force existing ones into early retirement.

However, the casualties will extend well beyond the coal industry, hurting families and businesses and taking a significant toll on American manufacturing across the nation. Congress should stop the EPA and all other federal agencies from regulating carbon dioxide and other greenhouse gas emissions.

Driving Energy Prices Up, Economic Activity Down. Coal provides approximately 40 percent of America's electricity generation.[2] By significantly limiting the use of an affordable energy source, the EPA's regulations will increase electricity prices for American households. Since low-income families spend a larger proportion of their income on energy, a tax that increases energy prices would disproportionately affect the budgets of the poorest American families.

This paper, in its entirety, can be found at **http://report.heritage.org/ib4158**

Produced by the Thomas A. Roe Institute for Economic Policy Studies

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Higher energy prices as a result of the regulations will squeeze both production and consumption. Since energy is a critical input for most goods and services, Americans will be hit repeatedly with higher prices as businesses pass higher costs onto consumers. However, if a company had to absorb the costs, high energy costs would shrink profit margins and prevent businesses from investing and expanding. The cutbacks result in less output, fewer new jobs, and less income.

Heritage Foundation analysts modeled the economic effects of a phase-out of coal between the years 2015 and 2038. Using the Heritage Foundation Energy Model, a derivative of the federal government's National Energy Model System, we found that by the end of 2023, nearly 600,000 jobs will be lost, a family of four's income will drop by $1,200 per year, and aggregate gross domestic product decreases by $2.23 trillion over the entire period of the analysis.[3]

Manufacturing Hit Hard. America's manufacturing base will be particularly harmed by the EPA's climate regulations. Manufacturing accounts for over 330,000 of the jobs lost.[4] This occurs for a number of reasons.

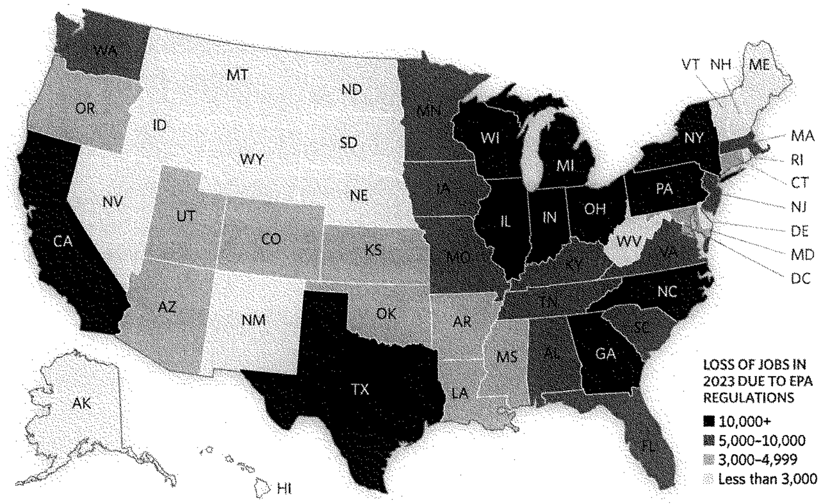
As more coal generation is taken offline, the marketplace must find a way to make up for that lost supply. The Heritage Energy Model builds in the most cost-effective means of replacing the lost coal through a combination of consumers decreasing energy use as an adjustment to higher prices and increased power generation from other sources.

Manufacturing is an energy-intensive industry, and the impact of the higher energy prices on manufacturing averages to more than 770 jobs losses per congressional district. However, not all regions are

MAP 1

The Cost of EPA Regulations: 336,000 Manufacturing Jobs in One Year

In just one year (2023), Environmental Protection Agency regulations on electric plants would eliminate 336,000 manufacturing jobs around the U.S. The map below shows the breakdown by state.



California	-37,439	Massachusetts	-6,920	Nebraska	-2,277
Texas	-24,504	Virginia	-6,592	New Hampshire	-1,978
Ohio	-18,191	South Carolina	-6,149	Idaho	-1,545
Illinois	-17,115	Alabama	-6,143	West Virginia	-1,414
Pennsylvania	-16,576	Kentucky	-5,626	Maine	-1,359
Michigan	-16,215	Iowa	-5,140	Rhode Island	-1,295
New York	-13,868	Arizona	-4,564	Nevada	-1,150
Indiana	-12,520	Oregon	-4,379	New Mexico	-990
North Carolina	-12,032	Connecticut	-4,339	South Dakota	-929
Wisconsin	-11,702	Colorado	-4,078	Delaware	-920
Georgia	-10,360	Kansas	-3,938	Vermont	-789
Florida	-9,921	Arkansas	-3,912	North Dakota	-594
New Jersey	-8,497	Oklahoma	-3,723	Montana	-481
Minnesota	-8,465	Louisiana	-3,605	Hawaii	-443
Tennessee	-8,114	Mississippi	-3,477	Alaska	-300
Washington	-7,492	Maryland	-3,377	Wyoming	-280
Missouri	-7,164	Utah	-3,111	District of Columbia	-84

Source: Calculations based on data from the Heritage Foundation Energy Model and employment data from the U.S. Census Bureau, American Community Survey.

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affected the same, as districts in Wisconsin, Ohio, Indiana, Michigan, and Illinois are especially hit hard. In fact, 19 out of the top 20 worse off congressional districts from the Administration's war on coal are located in the Midwest region. In those districts, the manufacturing industry, on average, will slash more than 1,600 jobs by 2023. The table at the end of the paper shows the estimates of the decrease of manufacturing employment per congressional district by 2023.

Furthermore, manufacturing growth will be harmed as a result of the fuel switching that will occur to make up for lost coal generation. Natural gas will be diverted away from manufacturing and to power generation. As a result, the Heritage Energy model projects that natural gas prices will increase 28 percent by 2030.

Natural gas and liquids produced with natural gas provide a feedstock for fertilizers, chemicals and pharmaceuticals, waste treatment, food processing, fuel for industrial boilers, transportation fuel, and much more. The chemical-manufacturing base alone is building 148 new operations topping over $100 billion in response to current and projected low natural gas prices from the shale gas boom.[5] As the U.S. is experiencing a renaissance in manufacturing and energy-intensive industries, the Administration's war on coal could adversely affect America's competitive advantage.

Availability of Carbon Capture and Sequestration. The primary reason the EPA's regulations will ban the construction of coal-fired electricity generating units is that to meet the thresholds,

TABLE 1

Six Midwest States Hit Hardest by EPA Regulations

MANUFACTURING JOB LOSSES IN 2023, AS AN AVERAGE FOR CONGRESSIONAL DISTRICTS

Wisconsin	-1,463	Nebraska	-759
Indiana	-1,391	Washington	-749
Iowa	-1,285	Oklahoma	-745
Michigan	-1,158	Georgia	-740
Ohio	-1,137	New Jersey	-708
Minnesota	-1,058	California	-706
New Hampshire	-989	Texas	-681
Kansas	-985	Maine	-680
Arkansas	-978	Rhode Island	-648
Illinois	-951	Louisiana	-601
Kentucky	-938	Virginia	-599
South Dakota	-929	North Dakota	-594
North Carolina	-926	Colorado	-583
Pennsylvania	-921	New York	-514
Delaware	-920	Arizona	-507
Tennessee	-902	Montana	-481
Missouri	-896	West Virginia	-471
South Carolina	-878	Maryland	-422
Alabama	-878	Florida	-367
Oregon	-876	New Mexico	-330
Mississippi	-869	Alaska	-300
Connecticut	-868	Nevada	-288
Vermont	-789	Wyoming	-280
Utah	-778	Hawaii	-222
Idaho	-773	D.C.	-84
Massachusetts	-769		

Source: Calculations based on data from the Heritage Foundation Energy Model and employment data from the U.S. Census Bureau, American Community Survey.

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1. Zack Coleman, "White House adviser: 'War on coal is exactly what's needed'" *The Hill*, June 25, 2013, http://thehill.com/blogs/e2-wire/e2-wire/307571-white-house-adviser-war-on-coal-is-exactly-whats-needed (accessed February 28, 2014).
2. U.S. Energy Information Agency, "Short Term Outlook—February 2014," Table 7d, http://www.eia.gov/forecasts/steo/tables/pdf/7dtab.pdf (accessed February 26, 2014).
3. See Nicolas D. Loris, Kevin D. Dayaratna, and David W. Kreutzer, "EPA Power Plant Regulations: A Backdoor Energy Tax," Heritage Foundation *Backgrounder* No 2683, December 5, 2013, http://www.heritage.org/research/reports/2013/12/epa-power-plant-regulations-a-backdoor-energy-tax (accessed February 26, 2014).
4. Out of a total of 670,000 jobs lost. This differs from the estimates referred to earlier (600,000 jobs lost), which are calculated from the Heritage Foundation Energy Model using employment figures from the Current Population Survey. These new estimates are calculated from the same Heritage Foundation Energy Model but use employment data from the American Community Survey in order to illustrate the impact in various congressional districts. Other coal dependent states that are not heavy manufacturers will also be significantly impacted by the EPA's regulations. For instance, although West Virginia and Wyoming are relatively low on manufacturing jobs lost, Heritage estimates these will be the two hardest hit states in terms of overall job losses per 100,000 employed. For a more detailed explanation of the overall job losses and methodology, see ibid.
5. *Business Standard*, "U.S. Chemical Industry Invest $100 Bn Due to Shale Gas Boom," February 22, 2014, http://www.business-standard.com/content/b2b-chemicals/us-chemical-industry-invest-100-bn-due-to-shale-gas-boom-114022400678_1.html (accessed February 26, 2014).

new plants will have to install carbon capture and sequestration (CCS) technology. As identified by the Obama Administration's Interagency Task Force on Carbon Capture and Storage 2010 report, implementation of CCS has a number of extremely difficult obstacles to overcome. There are questions of technical scalability, regulatory challenges, long-term liability of storing the captured carbon dioxide, and above all, cost.[6]

No credible basis exists to state that CCS is adequately demonstrated today, since no large-scale power plant in the U.S. has CCS. One large-scale CCS project is currently under contract—the Kemper County Integrated Gasification Combined Cycle (IGCC) plant—but it is hardly a model for new coal-fired plants for the rest of the country. Setting aside the fact that the project has had nearly half a billion dollars in cost overruns and received over $400 million in Department of Energy grants and preferential tax credits,[7] the plant is using a lower-grade lignite coal rather than higher-grade bituminous and subbituminous coal found in many parts of the rest of the country.

The Kemper plant will use IGCC technology that turns coal into gas as opposed to pulverized combustion and the captured carbon dioxide will serve a purpose for enhanced oil recovery to help finance the plant. New coal-fired plants in other parts of the country will not have those opportunities, so the Kemper plant is not an indicator of adequate demonstration. Further, the fact that the plant is not actually operating disqualifies it as the model. CCS should be pursued only if companies believe it is in their economic interest to do so—for instance, if profitable opportunities for enhanced oil recovery exist nearby.

Congress Stepping In. Senator Joe Manchin (D-WV) and Representative Ed Whitfield (R-KY) have introduced the Electricity Security and Affordability Act (H.R. 3826) that would require that greenhouse gas regulations for electricity generating units meet certain standards that prove they are economically feasible to achieve and have a demonstrated positive environmental benefit. Any imposed standards to limit or contain emissions cannot have been tested in isolation and with special treatment like the Kemper plant but must have been used commercially for a year by multiple plants (at least six) in multiple regions in order to be representative of the industry.

To truly ensure that the technology is cost-effective, Congress should strip away all subsidies and Department of Energy spending for CCS in order to prevent the federal government from presenting a handful of fundamentally uneconomic CCS plants as proof that the standards are legitimate. However, the most effective policy solution would be to prohibit the EPA and all agencies from regulating greenhouse gas emissions.

*—**Nicolas D. Loris** is Herbert and Joyce Morgan Fellow in the Thomas A. Roe Institute for Economic Policy Studies and **Filip Jolevski** is a Research Assistant in the Center for Data Analysis at The Heritage Foundation.*

6. Environmental Protection Agency, "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf (accessed February 26, 2014).
7. Massachusetts Institute of Technology, "Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project," http://sequestration.mit.edu/tools/projects/kemper.html (accessed February 26, 2014).

ISSUE BRIEF | NO. 4158
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TABLE 2

The Effects of EPA Regulations on Manufacturing Jobs, by Congressional District

The Environmental Protection Agency's regulations on electric power plants would cause the loss of hundreds of thousands of jobs around the U.S., most significantly in the manufacturing sector. The table below shows the number of manufacturing jobs lost, by state and congressional district, due to the regulations in just one year, 2023. ***The total for the U.S. would be 336,000 manufacturing jobs lost.***

ALABAMA	
1	-731
2	-813
3	-1,025
4	-1,175
5	-1,037
6	-669
7	-693
Total	-6,143
ALASKA	
At Large	-300
ARIZONA	
1	-382
2	-445
3	-409
4	-355
5	-783
6	-489
7	-557
8	-452
9	-692
Total	-4,564
ARKANSAS	
1	-967
2	-597
3	-1,201
4	-1,147
Total	-3,912
CALIFORNIA	
1	-356
2	-468
3	-466
4	-433
5	-733
6	-345
7	-427
8	-362
9	-537
10	-794
11	-470
12	-547
13	-531
14	-585
15	-986
16	-535
17	-1,819
18	-1,278
19	-1,275
20	-432
21	-372
22	-424
23	-410
24	-527
25	-826
26	-715
27	-625
28	-502
29	-758
30	-607
31	-639
32	-895
33	-751
34	-832
35	-960
36	-259
37	-469
38	-962
39	-985
40	-1,140
41	-683
42	-801
43	-781
44	-942
45	-1,008
46	-1,119
47	-863
48	-969
49	-698
50	-664
51	-454
52	-865
53	-555
Total	-37,439
COLORADO	
1	-516
2	-773
3	-364
4	-728
5	-476
6	-536
7	-685
Total	-4,078
CONNECTICUT	
1	-847
2	-1,017
3	-920
4	-580
5	-975
Total	-4,339
DELAWARE	
At Large	-920
DISTRICT OF COLUMBIA	-84
FLORIDA	
1	-335
2	-295
3	-331
4	-432
5	-397
6	-393
7	-412
8	-640
9	-305
10	-359
11	-292
12	-362
13	-571
14	-396
15	-438
16	-406
17	-248
18	-351
19	-218
20	-287
21	-302
22	-372
23	-393
24	-279
25	-506
26	-264
27	-337
Total	-9,921
GEORGIA	
1	-644
2	-623
3	-909
4	-589
5	-416
6	-605
7	-709
8	-633
9	-1,028
10	-730
11	-744
12	-753
13	-554
14	-1,423
Total	-10,360
HAWAII	
1	-256
2	-187
Total	-443
IDAHO	
1	-798
2	-747
Total	-1,545
ILLINOIS	
1	-495
2	-671
3	-901
4	-1,254
5	-811
6	-1,111
7	-530
8	-1,310
9	-660
10	-1,160
11	-1,009
12	-724
13	-715
14	-1,226
15	-1,057
16	-1,282
17	-1,228
18	-971
Total	-17,115
INDIANA	
1	-1,180
2	-1,874
3	-1,947
4	-1,402
5	-998
6	-1,524
7	-850
8	-1,486
9	-1,259
Total	-12,520
IOWA	
1	-1,537
2	-1,472
3	-782
4	-1,349
Total	-5,140
KANSAS	
1	-964
2	-834
3	-742
4	-1,398
Total	-3,938
KENTUCKY	
1	-1,083
2	-1,209
3	-814

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TABLE 2

The Effects of EPA Regulations on Manufacturing Jobs, by Congressional District

4	-1,036
5	-546
6	-938
Total	-5,626
LOUISIANA	
1	-582
2	-554
3	-659
4	-544
5	-472
6	-794
Total	-3,605
MAINE	
1	-717
2	-642
Total	-1,359
MARYLAND	
1	-670
2	-517
3	-450
4	-293
5	-302
6	-467
7	-349
8	-329
Total	-3,377
MASSACHUSETTS	
1	-876
2	-964
3	-1,252
4	-790
5	-613
6	-820
7	-450
8	-566
9	-589
Total	-6,920
MICHIGAN	
1	-714
2	-1,599
3	-1,324
4	-1,041
5	-863
6	-1,467
7	-1,244
8	-1,181
9	-1,293
10	-1,525
11	-1,430
12	-994
13	-799
14	-741
Total	-16,215
MINNESOTA	
1	-1,313
2	-1,032
3	-1,209
4	-965
5	-799
6	-1,276
7	-1,135
8	-736
Total	-8,465
MISSISSIPPI	
1	-1,198
2	-688
3	-744
4	-847
Total	-3,477
MISSOURI	
1	-662
2	-944
3	-1,090
4	-790
5	-766
6	-1,021
7	-881
8	-1,010
Total	-7,164
MONTANA	
At Large	-481
NEBRASKA	
1	-840
2	-617
3	-820
Total	-2,277
NEVADA	
1	-190
2	-486
3	-263
4	-211
Total	-1,150
NEW HAMPSHIRE	
1	-927
2	-1,051
Total	-1,978
NEW JERSEY	
1	-619
2	-498
3	-528
4	-517
5	-775
6	-732
7	-1,009
8	-755
9	-926
10	-455
11	-849
12	-834
Total	-8,497
NEW MEXICO	
1	-384
2	-301
3	-305
Total	-990
NEW YORK	
1	-506
2	-762
3	-401
4	-369
5	-313
6	-326
7	-459
8	-211
9	-228
10	-340
11	-274
12	-343
13	-291
14	-355
15	-237
16	-265
17	-427
18	-533
19	-589
20	-495
21	-655
22	-841
23	-1,076
24	-794
25	-949
26	-740
27	-1,089
Total	-13,868
NORTH CAROLINA	
1	-868
2	-1,049
3	-559
4	-614
5	-1,107
6	-1,110
7	-831
8	-1,110
9	-837
10	-1,323
11	-933
12	-754
13	-937
Total	-12,032
NORTH DAKOTA	
At Large	-594
OHIO	
1	-1,034
2	-1,038
3	-611
4	-1,683
5	-1,637
6	-1,001
7	-1,510
8	-1,468
9	-1,063
10	-860
11	-716
12	-893
13	-1,165
14	-1,436
15	-803
16	-1,273
Total	-18,191
OKLAHOMA	
1	-958
2	-881
3	-706
4	-613
5	-565
Total	-3,723
OREGON	
1	-1,425
2	-626
3	-876
4	-693
5	-759
Total	-4,379
PENNSYLVANIA	
1	-470
2	-294
3	-1,167
4	-1,196
5	-1,108
6	-1,132
7	-913
8	-1,079
9	-913
10	-1,008
11	-918
12	-849
13	-754
14	-548
15	-1,134
16	-1,236
17	-1,009
18	-848
Total	-16,576
RHODE ISLAND	
1	-657
2	-638
Total	-1,295

TABLE 2

The Effects of EPA Regulations on Manufacturing Jobs, by Congressional District

SOUTH CAROLINA	
1	-645
2	-716
3	-1,222
4	-1,203
5	-1,041
6	-646
7	-676
Total	-6,149
SOUTH DAKOTA	
At Large	-929
TENNESSEE	
1	-1,077
2	-748
3	-1,045
4	-1,202
5	-611
6	-993
7	-894
8	-991
9	-553
Total	-8,114
TEXAS	
1	-754
2	-931
3	-877
4	-890
5	-630
6	-942
7	-773
8	-711
9	-560
10	-827
11	-565
12	-883
13	-728
14	-896
15	-357
16	-450
17	-723
18	-713
19	-421
20	-385
21	-501
22	-792
23	-392
24	-825
25	-664
26	-802
27	-601
28	-301
29	-839
30	-601
31	-687
32	-801
33	-891
34	-307
35	-485
36	-999
Total	-24,504
UTAH	
1	-989
2	-647
3	-624
4	-851
Total	-3,111
VERMONT	
At Large	-789
VIRGINIA	
1	-455
2	-597
3	-692
4	-771
5	-783
6	-918
7	-507
8	-228
9	-923
10	-433
11	-285
Total	-6,592
WASHINGTON	
1	-1,043
2	-1,032
3	-781
4	-549
5	-527
6	-554
7	-668
8	-935
9	-886
10	-517
Total	-7,492
WEST VIRGINIA	
1	-568
2	-513
3	-333
Total	-1,414
WISCONSIN	
1	-1,566
2	-1,058
3	-1,301
4	-984
5	-1,621
6	-1,999
7	-1,408
8	-1,765
Total	-11,702
WYOMING	
At Large	-280

Source: Calculations based on data from the Heritage Foundation Energy Model and employment data from the U.S. Census Bureau, American Community Survey.

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LETTER SUBMITTED BY REPRESENTATIVE KEVIN CRAMER

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Jack Dalrymple	Wayne Stenehjem	Doug Goehring
Governor	Attorney General	Agriculture Commissioner

February 18, 2014

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
1200 Pennsylvania Avenue, NW (MC-4606M)
Washington D.C. 20460

Re: **Comments for consideration on US EPA's Draft *UIC Class VI Program: Guidance on Transitioning Class II to Class VI Wells***

Dear Sir/Madam:

The North Dakota Industrial Commission (NDIC) is pleased to provide these comments on the draft "Underground Injection Control (UIC) Guidance on Transitioning Class II Wells to Class VI Wells" (EPA 816-P-13-004) released for comment December 12, 2013.

In addition to providing comments on the draft guidance, the NDIC is also formally requesting the United States Environmental Protection Agency (USEPA) reconsider the provision 40 CFR 144.19 Transitioning from Class II to Class VI and allow for public comment. These comments also serve as a request for reconsideration of the Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule December 10, 2010, promulgated on December 24, 2010 (75 Federal Register 77230 to 77303).

Request to Reconsider 40 CFR 144.19 and Open for Public Comment

The NDIC respectfully requests USEPA reconsider 40 CFR 144.19 Transitioning from Class II to Class VI and provide an opportunity for public comment. This reconsideration request is based on the unlawful adoption of 40 CFR 144.19 which was adopted pursuant to public comment as described in the Class VI Final Rule Preamble (77243-77245 *H. How does this rule affect existing injection wells under the UIC program?*) without an opportunity for public comment. Changes may be made to a proposed rule based on the public comments received. *Shell Oil Co. v. E.P.A.*, 950 F.2d 741, 750 (D.C. Cir. 1991). However, any changes made to a *final rule must be of a type that could have been reasonably anticipated by the public – a logical* outgrowth of the proposal. *Id.*

The United States Court of Appeals describes the "logical outgrowth" test as follows:

> "A final rule is a logical outgrowth of the proposed rule 'only if interested parties should have anticipated that the change was possible, and thus

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> reasonably should have filed their comments on the subject during the notice-and-comment period.'" *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 626 F.3d 84, 94-95 (D.C. Cir. 2010) (quoting *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 407 F.3d 1250, 1259 (D.C. Cir. 2005)). Notice of agency action is "crucial to 'ensure that agency regulations are tested via exposure to diverse public comment, ... to ensure fairness to affected parties, and ... to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review'." *Id.* at 95 (quoting *Int'l Union*, 407 F.3d at 1259).

Daimler Trucks N. Am. LLC v. EPA, 737 F.3d 95, 100 (D.C. Cir. 2013).

If the "logical outgrowth test" is not met, agencies must provide a second notice with an opportunity for public comment on the changes. *Paralyzed Veterans of Am. v. D.C. Arena L.P.*, 117 F.3d 579, 586 (D.C. Cir. 1997).

40 CFR 144.19 is not a logical outgrowth from the Class VI rule proposed for public review and comment on July 25, 2008 (the comment period for the proposed Class VI rule closed December 24, 2008). USEPA adopted 40 CFR 144.19 pursuant to comments it received and added the provision to the final rule published on December 10, 2010, without providing a second notice or opportunity for public comment. The adoption of this provision is a change in philosophy from the proposed rule to the final rule. USEPA stated in the preamble of the proposed rule, "injection of CO_2 for the purposes of enhanced oil and gas recovery (EOR/EGR), as long as any production is occurring, will continue to be permitted under the Class II program." The final rule preamble describes USEPA's change in philosophy from the proposal:

> "EPA proposed that the Class VI GS requirements would not apply to Class II ER wells as long as any oil or gas production is occurring, but would apply only after the oil and gas reservoir is depleted. Under the proposed approach, Class II wells could be used for the injection of CO_2, as long as oil production is simultaneously occurring from the same formation. The preamble to the proposal sought comment on the merits of this approach.
>
> Some commenters agreed with the proposed approach while others suggested that the approach did not adequately address risks posed to USDWs by injection operations transitioning from production to long-term storage of CO_2. A majority of commenters requested that EPA develop specific criteria for this transition.
>
> Consistent with these comments, EPA determined that owners or operators of wells injecting CO_2 in oil and gas reservoirs for GS where there is an increased risk to USDWs compared to traditional Class II operations using CO_2 should be required to obtain a Class VI permit, with some special

> consideration for the fact that they are transitioning from a well not originally designed to meet Class VI requirements."

The proposed rule provided that there would be no transition "as long as any oil or gas production is occurring". The final rule, however, creates a transition point which will take place while oil production is occurring. North Dakota did not anticipate this significant change to the rule and therefore was denied an opportunity to comment. 40 CFR 144.19 and this draft guidance clearly indicate that what is published in the final rule is not a logical outgrowth from what was originally proposed.

Guidance Attempts to Expand USEPA Authority:
This guidance document appears to be an attempt to expand the authority of the USEPA by overfiling State Class II primacy programs. Under the guidance, the Class II UIC program Director and/or the EOR project operator are potentially required to report any and all data that may be requested by the Class VI UIC program Director (as of September 7, 2011 USEPA Regional Administrators or USEPA Administrator). Furthermore, this guidance appears to expand the authority of the Class VI UIC program Director over a Class II program or a Class II operator by allowing the Class VI UIC program Director the authority to require additional information/data to make a determination whether the Class II project can continue or should be required to transition. The Class VI UIC program Director has no authority over the Class II UIC program Director, nor does the Class VI UIC program Director have authority over the Class II project owner or operator.

Interpretation of CFR
The NDIC strongly disagrees with USEPA's interpretation of 40 CFR 144.17 on page 6:

> *40 CFR 144.17 provides either the Class II or Class VI UIC Program Director with the authority to require that a Class II owner or operator "conduct monitoring, and provide other information as is deemed necessary to determine whether the owner or operator has acted or is acting in compliance with Part C of the SDWA or its implementing regulations." This could include requesting information needed to determine whether the injection may lead to an increased risk to USDWs relative to Class II operations.*

Allowing the Class VI UIC program Director to require the Class II owner or operator to *"conduct monitoring, and provide other information as is deemed necessary to determine whether the owner or operator has acted or is acting in compliance with Part C of the SDWA or its implementing regulations"*, would conflict with State Class II primacy where the State is the primary regulatory authority. This would be considered overfiling should the Class VI UIC program Director require a Class II owner or operator to report directly to USEPA.

The NDIC interprets 40 CFR 144.17 as allowing the UIC program Director the flexibility to require the owner or operator to establish and maintain records, make reports, conduct monitoring, and provide other information as it relates to the well class under its primacy authority; not as allowing the UIC program Director to overfile injection well classes it does not directly regulate (i.e. the Class VI UIC program Director has direct regulatory authority over the

Class VI UIC program and the Class II UIC program Director has direct regulatory authority over the Class II UIC program). The NDIC has administered the 1425 UIC program regulating Class II injection well activities in North Dakota since 1983. The USEPA currently administers the Class VI UIC program in North Dakota. Under North Dakota's Class II UIC program primacy agreement with USEPA it would be consider overfiling if USEPA bypassed the NDIC and attempted to directly regulate a Class II owner or operator. USEPA's interpretation of 40 CFR 144.17 can be construed as an attempt to expand the direct regulatory authority of the Class VI UIC program Director. The only way USEPA's interpretation would be permissible is if the Class II program and the Class VI program were regulated under the same primacy authority. Under Safe Drinking Water Act (SDWA) Part D – Emergency Powers, Section 1431 (a) the USEPA can enact its overfiling authorities, when a "State or local authorities have not acted to protect the health of such persons, [USEPA Administrator] may take such actions as he may deem necessary in order to protect the health of such persons." In the context of the UIC program, the USEPA does not have the authority to overfile a State administered Class II UIC program or directly regulate an operator of a carbon dioxide enhanced oil recovery project under the jurisdiction of a State administered Class II UIC program, unless the State Class II UIC program Director has not acted to protect USDWs or the health of such persons pursuant to the SDWA.

The NDIC strongly disagrees with USEPA's interpretation of 40 CFR 144.51(h) on page 6:

> *40 CFR 144.51(h) requires permittees to provide "any information which the Director may request to...determine compliance with [a] permit." This gives the Class II UIC Program Director the authority to include Class II permit provisions to gather information that may be needed in the future to determine whether the project meets the definition of a Class II well or whether re-permitting as a Class VI well is necessary.*

The USEPA interpretation appears to obscure the lines between the Class II UIC program and the Class VI UIC program. The USEPA interpretation of 40 CFR 144.51 (h) which grants the Class II UIC program Director the authority to include additional permit provisions for a future determination, appears to create a process to add Class VI requirements to a Class II permit. The NDIC interprets 40 CFR 144.51 (h) as allowing the UIC program Director the flexibility he/she may need to require "any information" pertaining to the determination of whether the operator is operating the injection well as permitted. The USEPA's interpretation appears to constitute an overfiling prior to any determination that the Class II UIC program Director has not acted to protect human health and the environment.

In addition, USEPA describes a "project" as meeting the definition of a Class II well. This is a common inaccuracy throughout the draft guidance where USEPA misapplies the term "project" when referring to individual wells. The SDWA and the UIC program do not grant USEPA the authority over enhanced recovery projects, nor does USEPA have authority over carbon dioxide storage projects. The USEPA authorities are limited to the injection well.

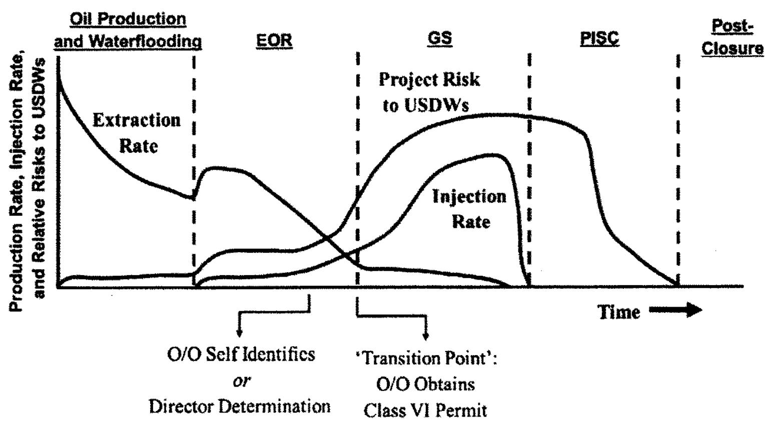
The NDIC recommends amending the above language as follows:

> *40 CFR 144.51(h) requires permittees to provide "any information which the Director may request to...determine compliance with [a] permit." ~~This~~ ~~gives~~ <u>Upon the owner or</u>*

U.S. –EPA
February 18, 2014
Page 5

<u>operator expressing intent to transition to Class VI injection this provision allows</u> the Class II UIC Program Director the authority to include Class II permit provisions to gather information that may be needed in the future to determine whether the project meets the definition of a Class II well or whether re-permitting as a Class VI well is necessary.

<u>Hypothetical EOR Project Transitioning to a GS Project</u>
The following diagram found on page 15 illustrates the transition point as taking place while oil production is occurring.



The NDIC requests further explanation of the specific parameters used to create this diagram as well as the data used to plot the graph and a description of why the injection rate increases as the extraction rate decreases. The NDIC is also requesting USEPA further explain the specific factors used in plotting project risk to underground sources of drinking water (USDWs); for example, does this diagram depict a specific geologic setting or is it a generalization of all EOR projects that transition into storage projects?

<u>Traditional EOR</u>
USEPA uses the term "traditional Class II operations" and "traditional EOR projects" when comparing increased risk to USDWs in a carbon dioxide enhanced oil recovery project. The word "traditional" should be defined, especially as the enhanced oil and gas recovery industry increases its use of anthropogenic carbon dioxide, explores potential "unconventional" oil reservoirs, and adapts to new technologies and modern approaches of oil recovery while simultaneously storing carbon dioxide.

U.S. -EPA
February 18, 2014
Page 6

Equally as Protective
Class II injection wells are equally protective of USDWs as compared to Class VI. USEPA states, "The Class VI requirements are more comprehensive and specific than the Class II requirements", but both well classes are designed to protect USDWs.

Individual Injection Well versus EOR/CCS Projects:
Throughout this guidance document USEPA uses the term "project" when referring to a carbon dioxide enhanced oil recovery Class II injection well or a Class VI carbon dioxide storage injection well. The context in which this guidance document refers to enhanced oil or gas recovery projects transitioning into geologic storage projects is beyond the authority of USEPA and the UIC program. The USEPA's authority is limited to the injection well. For example, the title of the guidance document describes the transition as "Class II Wells to Class VI Wells." The UIC program is defined in this guidance document as follows:

> **Underground Injection Control Program** refers to the program USEPA, or an approved state, is authorized to implement under the Safe Drinking Water Act (SDWA) that is responsible for regulating the underground injection of fluids by wells injection. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.

Throughout this guidance, USEPA mistakenly describes the transition from an injection well to a project and vice versa. For example on page 31, "Following a determination that there is an increased risk to USDWs from the injection project (see Section 3), owners or operators will need to apply for a Class VI permit." A project more than likely would consist of multiple injection wells, facilities, and potentially multiple types of wells (i.e. injection, production, and disposal).

The NDIC recommends USEPA replace "project" with "injection well" throughout this draft guidance, where appropriate.

Transitioning a Project from Mineral Rights to Storage Rights
The SDWA authority does not extend to private minerals or pore space ownership, further complicating the entire concept of transitioning a carbon dioxide enhanced recovery project to a carbon dioxide storage project. In North Dakota, the pore space is owned by the overlying surface estate rather than a severed mineral owner. The NDIC regulates the drilling and production of oil and gas in North Dakota with the mission:

> ...to foster, to encourage, and to promote the development, production, and utilization of natural resources of oil and gas in the state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas be had and that the correlative rights of all owners be fully protected; and to encourage and to authorize cycling, recycling, pressure maintenance, and secondary recovery operations in order that the greatest possible economic recovery of oil and gas be

> obtained within the state to the end that the landowners, the royalty owners, the producers, and the general public realize and enjoy the greatest possible good from these vital natural resources.

N.D.C.C. § 38-08-01

It is of great concern to the NDIC that the transition discussed in this USEPA guidance would potentially conflict with this agency's mission to prevent waste, maximize recovery, and fully protect correlative rights.

Sincerely,

Jack Dalrymple
Governor

Wayne Stenehjem
Attorney General

Doug Goehring
Agriculture Commissioner

WHITE PAPER SUBMITTED BY REPRESENTATIVE RANDY WEBER

Denbury

SUBPART RR FLAWS PRECLUDE EPA'S RELIANCE ON CO_2-EOR IN THE PROPOSED NSPS RULE

I. THE ROLE EPA EXPECTS CO_2-EOR TO PLAY UNDER THE NSPS RULE AND THE SUBPART RR REQUIREMENT

EPA's proposed NSPS rule relies on CCS as the "best system of emissions reduction" that has been "adequately demonstrated", a finding that is legally required by the relevant statute for EPA to adopt the emission standard. EPA's cost assessment of CCS is based in material part on the agency's expectation that "new fossil fuel-fired EGUs that install CCS will generally make the captured CO_2 available for use in EOR operations" and its belief that "use of EOR lowers costs for production of domestic oil."[1] Under the proposed rule, an *emitter may use* the EOR-based storage to meet the performance standard *only where the offsite injector reports* the CO_2 storage to EPA under Subpart RR of the GHG reporting rules.[2] This results in an emitter trying to enforce an EPA rule upon an EOR operator now only subject to Subpart UU of the GHG reporting rules. Under Subpart RR, an operator would have to submit and receive final approval of an MRV plan from the EPA following any appeals under Part 78 and subsequent judicial review.[3] This means that approval of an MRV plan is likely to be delayed and then finally determined through litigation. The proposed NSPS rule would thus impose federal regulation on drilling and subsurface operations of the oil and gas industry via rules applied to air emissions by electricity generating units.

II. THE SUBPART RR PROBLEM: THE CONFLICTING OBJECTIVES OF RESOURCE CONSERVATION AND WASTE DISPOSAL

Contrary to EPA's expectations, the proposed NSPS rule will ***foreclose – not encourage*** -- the use of CO_2 captured by emissions sources in EOR operations. The reason is that compliance with Subpart RR will transform an EOR operation from a resource recovery operation into a waste disposal operation. Subpart RR compliance will create regulatory uncertainty and risk that will result in EOR operators avoiding the purchase of CO_2 that is subject to those rules. Operators will likely prohibit CO_2 suppliers from commingling "Subpart RR CO_2" with other CO_2 supplies being transported for EOR operations. Indeed, the EOR offtake agreements underlying the existing projects upon which EPA relies to show that CCS has been "adequately demonstrated" would not have been entered into if Subpart RR compliance had been required. In sum, requiring Subpart RR compliance by the EOR operator in order for the emitter to meet the NSPS standard will in fact foreclose the development of capture projects that would otherwise include EOR offtake agreements.

[1] Proposed Rule at 262-263. See also at 272 (EPA expects that for the immediate future, captured CO_2 from affected units will be injected underground for geologic sequestration at sites where EOR is occurring).

[2] Proposed Rule, at 279 (if the captured CO_2 is injected offsite, then "the facility injecting the CO2 underground must report under . . . subpart RR".

[3] To be codified at 40 C.F.R. § 60.46Da(h)(5)(ii).

1. Subpart RR compliance will conflict with state mandates to conserve natural resources, prevent waste and protect correlative rights. The touchstones of state oil and gas law (including a number of State Constitutional mandates) are the conservation of natural resources, the prevention of waste and the protection of the correlative rights of all the affected mineral interest owners. Generally speaking, "waste" means operating wells in a way that reduces the total ultimate recovery of the resource. These legal principles are fundamental to countless commercial oil and gas industry agreements – mineral leases, unit or pooling agreements, operating agreements, and royalty agreements, to name but a few. Operators must prudently and diligently develop resources under mineral leases and avoid damaging the reservoirs or otherwise reducing the total ultimate recovery of the resource. For example, in Texas, the conservation and development of all natural resources is a "public right and duty" and the preservation of the State's natural resources "is an issue of constitutional dimension".[4]

In contrast, the EPA's rules and policies governing CO_2 storage for emissions reduction purposes are premised on a "waste disposal" model (which is why EPA based the Class VI geologic sequestration rules on the rules for Class I, waste disposal wells). Under the NSPS framework, CO_2 injectate is viewed as a waste to be permanently stored rather than a commodity to be used to maximize total ultimate recovery of the hydrocarbon resource. The whole thrust of EPA's reliance on CCS as an emissions reduction technology under the proposed NSPS rule will be focused on the goal of reducing emissions. Waste disposal considerations will permeate the entire closed loop CO_2 recycle system and transportation network, and will preclude future timely access to the remaining oil at the end of an EOR operation. Interfering with, delaying implementation of, and therefore reducing the total ultimate recovery of remaining oil from an EOR operation will constitute the "waste" of resources that is contrary to, and expressly prohibited by, state conservation law (including Constitutional law) as well as upsetting countless commercial agreements. While no one knows what an EPA-approved MRV plan may ultimately require (as explained below), operators are not going to risk acceptance of a plan that is counter to its duty as a prudent operator to conduct itself in a manner to increase the recovery of remaining resources.

Regulatory conditions that are onerous, restrictive, expensive, or technologically challenging will constitute substantial barriers for a prudent operator who must continually manage and change its injection operations for its developed projects in order to maximize the recovery of the remaining mineral resources. Such regulatory restrictions on the future recovery of remaining mineral resources will generate mineral property "takings" claims that thus far are fairly rare today, but could dominate the landscape under the proposed NSPS structure.

2. *Subpart RR is not merely a reporting rule, but is a vehicle for litigation-based, substantive regulation under the undefined MRV plans.* Subpart RR is not merely a reporting rule. It requires the operator to obtain approval by the EPA of a "monitoring, reporting and verification" plan. Absent an approved MRV plan, the operator will not be allowed to inject the CO_2. And, if a plan is approved, such plan must be maintained

[4] *Exxon Corporation, et al. v. Laurie T. Miesch et al.*, 180 S.W. 3d 299, 318 (Tex. App. 2005).

under the rule for a duration determined by the EPA, and not the EOR operator. Once a plan is administered, only the EPA can determine its closure; this in itself is an unacceptable scenario for the mineral interest owners who must wind down their activities when the purpose of the enhanced recovery of oil has come to an end. Moreover, there are no standards governing what may constitute an incomplete or otherwise unacceptable plan, nor any timeline for approval, creating a completely open-ended and undefined regulatory framework. Nevertheless, failure to monitor or report data according to the ultimately-approved MRV plan is subject to EPA enforcement action under the Clean Air Act,[5] penalties for which can be substantial.

Subpart RR further provides that operational changes -- even the drilling of a new injection well that had not previously been identified – can start the whole MRV approval process over again. It is important to remember that an EOR operation is a dynamic process that involves the drilling of multiple wells, the reconfiguration of wells from injectors to producers or vice versa, as well as adapting the original plans to respond to operational changes. This means that there will ***necessarily*** be a host of changes to the originally-approved plan. Any one of these changes may be sufficiently material to trigger the MRV approval process again.

These aspects of Subpart RR regulation mean that the developer of a generating project that is planning to transfer captured CO_2 for EOR operations will have no assurance that it will have an outlet for the to-be-captured CO2 until after litigation of the EOR operator's MRV plan is complete. It must further face that risk that subsequent operational changes by the EOR operator may trigger revisions to the MRV plan that prevent the EOR operator from approved reporting -- thereby jeopardizing compliance with the NSPS performance standards *by the emitting generating unit*. This could force the shutdown of the generation plant.[6]

EPA's reliance on Subpart RR compliance thus imposes severe regulatory barriers to the use of EOR-based storage to meet the NSPS standards. It is difficult to see how a project could be successfully developed, financed, and constructed under these rules.

3. *To avoid these conflicts, risks, and uncertainties, EOR operators are unlikely to either purchase "Subpart RR CO_2" or even to allow such gas to be commingled for transportation with ordinary CO_2.* While developers of proposed power plants designed to meet the proposed NSPS standard will expect potential purchasers to commit to become subject to Subpart RR, EOR operators will decline, because the restrictions, costs, risks, and uncertainties associated with Subpart RR status will make those supplies of CO_2 totally undesirable. Moreover, CO_2 pipeline operators may be expected to prevent the commingling of "Subpart RR CO_2" with ordinary CO_2 because of the fear

[5] EPA's Response to Comments, at 175. *See also* at 14.

[6] *See e.g.* Condition GHG-3 of California Energy Commission's Preliminary Staff Assessment and Draft EIS (docketed June 28, 2013 in Docket 08-AFC-8A) for a CCS project in that state would require the emitting power generation unit to cease operations if it is unable to demonstrate compliance with the emissions performance compliance plan or if the EOR operator permanently stops accepting CO2 for sequestration.

that the Subpart RR obligations will apply to the entire commingled stream (exactly as federal courts held that federal natural gas regulation applied to an entire commingled stream even where nearly all of the gas stream was intrastate in nature and not otherwise subject to federal regulation).[7]

As a result, the proposed NSPS rule makes it extremely unlikely that developers of proposed coal-fired projects will be able to enter into commercially-based offtake agreements with EOR operators for the to-be-captured CO_2. Indeed, the EOR offtake agreements underlying the *existing* power generation project upon which EPA relies to show that CCS has been "adequately demonstrated" would not have been signed if the now-proposed NSPS rule and mandated Subpart RR compliance had been in effect when those projects were finalized.

4. *None of the 1,000 million metric tons of CO_2 injected to date have been subject to Subpart RR.* Nearly 1,000 million metric tons of CO_2 have been successfully injected during EOR operations in the United States over the last forty years, representing a vast amount of actual experience and expertise with CO_2 injection and incidental storage during EOR operations. Of these 1,000 million tons, roughly 120 million have been reported to the EPA since the reporting rules took effect beginning in 2011, all of which has been reported under Subpart UU and not a single ton has come under the Subpart RR rules. There are no approved MRV plans for CO_2 injection in EOR operations for reporting under Subpart RR. Hence, rather than being "adequately demonstrated", the Subpart RR rules and procedures are unused, uncertain and unworkable for EOR operations.

[7] This concern was recognized in the 2010 report of the IOGCC's Pipeline Transport Task Force on CO_2 transportation.

REPORT SUBMITTED BY REPRESENTATIVE JIM BRIDENSTINE

NRDC
THE EARTH'S BEST DEFENSE

NATURAL RESOURCES DEFENSE COUNCIL

Comments on

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

77 Fed. Reg. 22,392 (April 13, 2012)

Comments on Measures Needed to Assure the Integrity of Carbon Capture and Storage in the Power Plant New Source Performance Standards

submitted by

Natural Resources Defense Council

June 25, 2012

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I. Introduction

We thank the Environmental Protection Agency (EPA) for the opportunity to comment on the proposed carbon pollution standards for new power plants. These comments are directed to requirements needed to assure the integrity of carbon capture and storage (sequestration) as a compliance option under the rule.

The Natural Resources Defense Council (NRDC) is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington D.C., San Francisco, Los Angeles, Chicago and Beijing.

II. Treatment of CCS under the proposed rule's compliance obligations

(1) General discussion

The proposed rule defines CCS as follows: "Carbon capture and storage (CCS) means a process that includes capture and compression of CO_2 produced by an electric utility generating unit before release to the atmosphere; transport of the captured CO_2 (usually in pipelines); and storage of that CO2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams".[1] The proposed rule clearly lists CCS as a compliance option and lists specific standards to be met by the EGU in the case that CCS is used towards compliance.[2]

We submit that EPA's standards must include provisions to address the risk of CO_2 leakage after CO_2 captured at the plant site leaves the site to be transported to, and disposed of in, a sequestration facility. To this end, the standards need to include (directly or by reference) requirements that captured CO_2 must be transported through approved pipelines to approved sequestration sites, where both the pipelines and sequestration sites are subject to appropriate requirements for preventing emissions, and for monitoring, quantifying, and reporting to detect and correct any such emissions. The standards must specify that an EGU source may subtract captured CO_2 from its reported CO_2 emissions only if these provisions are complied with.

CCS systems necessarily involve equipment and facilities beyond the EGU plant site. It would be utterly unacceptable for an EGU to capture CO_2 and pipe it off-site, only to have it released from the open end of a pipe across the fence-line. Thus, at a minimum, an EGU must not be allowed to deduct captured CO_2 from its emissions unless it has, and complies with, an

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[1] 77 Fed. Reg. 22439.
[2] 77 Fed. Reg. 22436-22437.

enforceable commitment to ship that CO_2 by a pipeline operating in compliance with containment, monitoring, and reporting requirements, to a sequestration facility that in turn operates in compliance with containment, monitoring, and reporting requirements.

Accordingly, unless the owners and operators of the receiving pipelines and sequestration facilities are subject to obligations to monitor and report CO2 emissions and are subject to noncompliance penalties no less stringent than those applicable to covered NSPS facilities under the Clean Air Act, any release from such pipelines and sequestration facilities of CO2 produced by a covered EGU must be attributed to the covered EGU for NSPS compliance purposes.

Further, EPA needs to adopt, directly in this rule or by reference, appropriate and specific standards for containing, monitoring, quantifying and reporting emissions from pipelines and sequestration facilities. Only upon compliance with such requirements shall the EGU be allowed to deduct sequestered CO_2 from its own emissions.

(2) EPA's Greenhouse Gas Reporting Rule and compliance with the proposed rule

With appropriate improvements, the CCS-related requirements of EPA's Greenhouse Gas Reporting Rule could form the basis of the provisions needed in the standards to set forth the compliance obligations of EGU sources that employ CCS systems. While EPA has adopted a general Greenhouse Gas Reporting Rule, that rule is not adequate on its own to assure compliance with the NSPS for EGUs. We address some of the needed improvements below.

Subparts UU and RR of the Greenhouse Gas Reporting Rule apply to facilities that inject and geologically sequester CO_2 respectively.

We do not consider reporting under subpart UU to be sufficient to assure compliance with the proposed NSPS, given that it amounts to no more than reporting meter readings and does not consider the potential for emissions from sequestration sites. EPA should not accept reporting under subpart UU of the Greenhouse Gas Reporting Rule by itself as sufficient for the purposes of compliance of CCS facilities under the proposed rule.

Subpart RR applies to facilities that geologically sequester CO_2 and includes additional obligations over subpart RR to identify CO_2 leakage pathways (including likelihood, magnitude and timing), delineate the monitoring area, identify a strategy for detecting and quantifying any surface leakage of CO_2, and identify a strategy for establishing expected baselines for monitoring CO_2 surface leakage.

However, reporting under subpart RR is not mandatory for all CO_2 injection facilities – only for wells that inject CO2 under Class VI of the Underground Injection Control Program (UIC). Furthermore, compliance with subpart RR by itself does not guarantee that adequate standards are met in order to satisfy the higher level of compliance requirements that are needed to effectively enforce the proposed rule, for several reasons. First, the requirements under subpart RR are general, and could be implemented very differently depending on the discretion of the Administrator. Second, Monitoring, Reporting and Verification (MRV) plans are reviewed on an individual basis and are not made public until finalized, with only an ex-post option for appeal to the Environmental Appeals Board for interested parties. Third, reporting under subpart RR does not require or guarantee that geologic sequestration sites are sited, operated and decommissioned in a way that will aim to prevent or minimize leaks to the atmosphere. The requirement is merely to report any emissions.

For these reasons, EPA should not accept reporting under subpart RR of the Greenhouse Gas Reporting Rule by itself as sufficient for the purposes of compliance of CCS facilities under the proposed rule. The informational and general nature of the Reporting Rule renders it unsuitable by itself for compliance with the proposed rule.

(3) UIC well classes and compliance with the proposed rule

We do believe that reporting under subpart RR could be used for compliance under the NSPS if combined with other EPA regulatory requirements. In particular, we believe that EGUs should be allowed to subtract from their on-site atmospheric emissions quantities of CO_2 that are being injected and sequestered (minus any leaks) in wells permitted under UIC Class VI (which makes reporting under subpart RR compulsory). However, we do not believe that the same should be allowed if CO_2 is being injected in Class II wells.

Class II dates back several decades and is used for injecting brines, CO_2 and other fluids associated with oil and gas production, and hydrocarbons for storage.[3] Class VI is a new injection well class, which was designed specifically for and applies to wells that inject CO_2 for geologic sequestration.[4] Class VI rules are far more recent than Class II rules, and were promulgated in December 2010.

[3] 40CFR144.6(b) defines Class II wells as "[w]ells which inject fluids:
(1) Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.
(2) For enhanced recovery of oil or natural gas; and
(3) For storage of hydrocarbons which are liquid at standard temperature and pressure.

[4] 40CFR 144.6(f) defines Class VI wells as "[w]ells that are not experimental in nature that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at §146.95 of this chapter; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to §§146.4 of this chapter and 144.7(d)."

Regulatory requirements for Class VI are more comprehensive than for Class II on many counts. Below we summarize some key differences:

- The information than needs to be submitted at the time of a permit application is more extensive under Class VI. For example, key geological, geomechanical, lithological and geochemical properties of the confining zone, information on faults or fractures that may interfere with confinement, seismic history, and information on wells with the area of review have to be submitted under a Class VI permit application. Class II does not have such requirements, or requires only information on known wells that is of public record rather than the use of methods to discover orphaned or abandoned wells.
- Class VI siting requirements include an injection zone with sufficient properties to receive the total anticipated volume of CO_2 injectate, a confining zone big enough to contain injected *and* displaced fluids, and with sufficient integrity to allow injection without initiating or propagating fractures. Class II requires only a confining zone that is free of transmissive faults and fractures.
- Monitoring requirements for Class II are limited to analyzing injected fluids with sufficient frequency to yield data representative of its chemical and physical characteristics, as well as injection rate, pressure and volume measurements. Class VI requirements include an extensive testing and monitoring plan that covers operational parameters for the well, direct and indirect methods to track the extent of the CO_2 plume and the area of elevated pressure, water quality measurements, as well as surface monitoring if required by the Director.
- Class VI requirements for a well plugging plan are tailored to individual situations rather than requiring off-the-shelf methods to be used.
- Class II lacks any post-injection site care and site closure requirements. Class VI requires post-injection monitoring for fifty years, or an alternative period if it can be shown that it is sufficient, in order to establish the evolution of the injected CO_2 and displaced fluids, and that no USDWs are being endangered. Once no endangerment established, then the Director may authorize site closure, at which point financial responsibility obligations cease.
- The area of review and corrective action requirements for Class VI are broader. The actual area of review does not rely on default distances, needs to be updated at least every five years, requires modeling of certain specifications to determine the extent of the CO_2 plume and displaced fluids, and more extensive identification of penetrations within the area of review. A revision of the area of review also may require revision of other required plans.
- Financial responsibility obligations under Class VI are more comprehensive than under Class II.

40CFR146.81(d) states that "Geologic sequestration means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport."

- Class VI emergency and remedial response provisions require actions by the owner or operator to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. Class II has no such requirements.
- Construction requirements, as well as requirements for logging, sampling and testing, go further in Class VI than they do in Class II.
- The standard for granting primacy to states for the implementation of the program is weaker for Class II wells, and consists of a general effectiveness demonstration as opposed to meeting individual stringency and adequacy criteria.

Class VI therefore contains comprehensive requirements tailored to geologic sequestration projects that aim to ensure that CO_2 does not contaminate groundwater. Preventing groundwater contamination serves the purpose of reducing the likelihood that injected CO_2 will enter the atmosphere. On the other hand, injection under Class II permits combined with reporting under subpart RR could leave substantial gaps in terms of safeguards for effective sequestration of CO_2, which would seriously compromise compliance under the proposed rule.

<u>EPA should allow EGUs to show compliance with the standards of the proposed rule by subtracting from their atmospheric emissions CO_2 that is being injected and sequestered (minus any leaks) in wells permitted under UIC Class VI and that report their emissions under subpart RR</u>.

Further, EPA should consider establishing a compliance demonstration pathway for sequestration facilities that are not covered by Class VI permits.

We believe that <u>EPA should propose and finalize requirements to classify carbon dioxide that is captured and injected during enhanced hydrocarbon recovery operations as geologically sequestered if it determines that conditions for site selection, operation, mitigation, remediation, monitoring, reporting and abandonment are met that will ensure minimum risk of, and appropriate response to, potential leakage from the intended carbon dioxide confinement zone.</u>

EPA regulations establishing requirements for qualifying carbon dioxide injected in Enhanced Hydrocarbon Recovery operations as geologic sequestration should include but not be limited to the following:

- A demonstration that sites are capable of long-term containment of carbon dioxide;
- Identification and characterization of potential natural and man-made leakage pathways, and appropriate risk management and corrective actions;
- Design, construction and operation parameters to prevent, mitigate and remediate the creation or activation of leakage pathways, or and the migration of CO_2 or fluids into any zone in a manner not authorized by the Administrator (or pursuant to a State program approved by the Administrator as meeting the requirements of these regulations);

- Minimizing fugitive CO_2 emissions from project operations;
- Monitoring and modeling to predict and confirm the position and behavior of the CO2 and other fluids in the subsurface during and after injection;
- Accounting and reporting of CO_2 quantities sequestered, injected, recycled, leaked, vented, and any other categories as appropriate; and,
- Post-injection site closure and financial responsibility requirements that ensure the long-term containment of injected CO_2.

Pending the promulgation or revision of such regulations by EPA, the Agency should approve applications for qualification of carbon dioxide injected in Enhanced Hydrocarbon Recovery operations as geologically sequestered for the purposes of the proposed rule pursuant to guidelines that conform to the requirements above.

(4) Carbon Capture and Storage Needs to be Further Defined to Assure Permanent Sequestration

As noted above, EPA needs to refine the definition of carbon capture and storage to assure permanent sequestration. <u>We suggest that EPA add the word "permanent" to the proposed definition of CCS:</u>

> Carbon capture and storage (CCS) means a process that includes capture and compression of CO2 produced by an electric utility generating unit before release to the atmosphere; transport of the captured CO2 (usually in pipelines); and *permanent* storage of that CO2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams.

Further, <u>EPA should define geologic sequestration consistently with its Safe Drinking Water Act regulations to mean the permanent containment of a gaseous, liquid, or supercritical carbon dioxide stream injected in subsurface geologic formations that are shown to have the suitable characteristics necessary to provide such containment, under operating and abandonment conditions, and requirements designed to ensure and verify such containment, as determined by the Administrator</u>.

III. Conclusion

We thank EPA for the opportunity to comment on the proposed rule. NRDC continues to believe strongly that geologic sequestration of CO2, correctly implemented, must be a component of the U.S. climate mitigation portfolio. However, the proposed carbon pollution standards for new power plants must ensure that the technology is deployed safely and effectively, and must not create a precedent whereby emitters are allowed to treat carbon dioxide that is captured, transported and sequestered without the appropriate safeguards that will ensure that it is not emitted to the atmosphere and that it does not endanger human health or the environment.

LETTER SUBMITTED BY REPRESENTATIVE JIM BRIDENSTINE

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON D.C. 20460

OFFICE OF THE ADMINISTRATOR
SCIENCE ADVISORY BOARD

January 29, 2014

EPA-SAB-14-003

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Subject: Science Advisory Board (SAB) Consideration of EPA Planned Actions in the Spring 2013 Unified (Regulatory) Agenda and their Supporting Science

Dear Administrator McCarthy:

As part of its statutory duties, the Science Advisory Board (SAB) recently concluded a series of discussions about possible review of the science supporting major EPA planned actions. The EPA Office of Policy provided notice of release of the Spring 2013 Semiannual Regulatory Agenda on July 3, 2013. Since that time, the SAB held a public meeting on December 4-5, 2013 and public teleconference on January 21, 2014 to discuss whether to review the science supporting any of the planned regulatory actions in that agenda in order to provide advice and comment on the adequacy of the science, as authorized by section (c) of the Environmental Research, Development and Demonstration Authorization Act.

The SAB appreciates the information provided by the EPA Office of Policy and the EPA program offices describing the planned actions, associated scientific questions, and agency plans for scientific analyses and peer review. The SAB also appreciates information provided by the public regarding the planned actions. The written information provided and the results of fact-finding discussions with EPA Staff are available on the SAB website.

The SAB focused its attention on 11 major actions identified by the EPA Office of Policy as being planned but not yet proposed as of the date the Semiannual Regulatory Agenda was published in the *Federal Register* on July 3, 2013. After discussions held at the public meeting on December 4-5, 2013 and the public teleconference on January 21, 2014, the SAB decided that it will not undertake review of the science supporting any actions in the semi-annual regulatory agenda at this time. However, the SAB wishes to communicate three important points related to the review of major planned actions included in the Spring 2013 Semiannual Regulatory Agenda.

First, in regard to the planned action entitled *Revision of 40 CFR Part 192 -- Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings and Uranium In Situ Leaching Processing Facilities* (2060-AP43), the SAB wishes to evaluate the science supporting the proposed rule after it is proposed, when more information about the proposed rule and the science supporting it are made available. At that time the SAB will determine whether it wishes to offer advice and comment to the Administrator. The SAB made this decision because there was insufficient information provided by the agency to date about the scientific and technical basis for this planned action.

Second, in regard to the action entitled *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generation Units* (2060-AQ91), the SAB defers to EPA's legal view, communicated to the SAB by staff from EPA's Office of Air and Radiation, that the portion of the rulemaking addressing coal-fired power plants focuses on carbon capture and that the regulatory mechanisms for addressing potential risks associated with carbon sequestration are not within the scope of the Clean Air Act. Carbon sequestration, however, is a complex process, particularly at the scale required under this rulemaking, which may have unintended multi-media consequences. The Board's strong view is that a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in important systematic ways to this rulemaking. Research and information from the EPA, Department of Energy, and other sources related to carbon sequestration merit scientific review by the National Research Council or the SAB. Indeed, the Board notes that Section 704 of the Energy Independence and Security Act of 2007 directly calls for the National Research Council to review such research conducted by the Department of Energy and that this review has not yet occurred. The SAB asks the EPA to explore options for conducting such a review in a timely manner. The Board also advises the agency to monitor technological progress on carbon capture as the regulation is implemented.

Third, and more generally, the SAB is seeking ways to improve the process for future review of the semi-annual regulatory agenda. The Board requests that the EPA describe in a more complete and consistent manner the scientific and technological bases for major planned actions and associated peer review. More complete and timely agency information when the Board begins considering the regulatory agenda will enable the SAB to make informed decisions in an expeditious manner about whether to provide advice and comment on science supporting planned agency actions. The SAB Staff Office will be meeting soon with EPA program offices to discuss improved processes to provide the SAB with the information needed for the Board's deliberations.

On behalf of the SAB, I thank you for the opportunity to support EPA through consideration of the science supporting actions in the agency's regulatory agenda.

Sincerely,

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Dr. David T. Allen, Chair
Science Advisory Board

Enclosure

(1) Roster of SAB Members

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