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

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[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.