Report of the Interagency Task Force on Carbon Capture and Storage

August 2010

Table of Contents

This report provides a background discussion on a range of factual, policy and legal issues. The discussion contained in this report is not intended to create rights or remedies that benefit the public or any regulated entity. The background discussion in this report also should not be construed to provide an authoritative or binding analysis or interpretation of any statute or regulation; such interpretations are issued through other processes. Finally, this report does not reflect the legal position of the United States.

Executive Summary

Introduction

Carbon capture and storage (CCS) refers to a set of technologies that can greatly reduce carbon dioxide (CO_2) emissions from new and existing coal- and gas-fired power plants, industrial processes, and other stationary sources of CO_2. In its application to electricity generation, CCS could play an important role in achieving national and global greenhouse gas (GHG) reduction goals. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available and a supportive national policy framework is in place.

In keeping with that objective, on February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage composed of 14 Executive Departments and Federal Agencies. The Task Force, co-chaired by the Department of Energy (DOE) and the Environmental Protection Agency (EPA), was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. Composed of more than 100 Federal employees, the Task Force examined challenges facing early CCS projects as well as factors that could inhibit widespread commercial deployment of CCS. In developing the findings and recommendations outlined in this report, the Task Force relied on published literature and individual input from more than 100 experts and stakeholders, as well as public comments submitted to the Task Force. The Task Force also held a large public meeting and several targeted stakeholder briefings.

While CCS can be applied to a variety of stationary sources of CO_2, its application to coal-fired power plant emissions offers the greatest potential for GHG reductions. Coal has served as an important domestic source of reliable, affordable energy for decades, and the coal industry has provided stable and quality high-paying jobs for American workers. At the same time, coal-fired power plants are the largest contributor to U.S. greenhouse gas (GHG) emissions, and coal combustion accounts for 40 percent of global carbon dioxide (CO_2) emissions from the consumption of energy. EPA and Energy Information Administration (EIA) assessments of recent climate and energy legislative proposals show that, if available on a cost-effective basis, CCS can over time play a large role in reducing the overall cost of meeting domestic emissions reduction targets. By playing a leadership role in efforts to develop and deploy CCS technologies to reduce GHG emissions, the United States can preserve the option of using an affordable, abundant, and domestic energy resource, help improve national security, help to maximize production from existing oil fields through enhanced oil recovery (EOR), and assist in the creation of new technologies for export.

While there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies. Administration analyses of proposed climate change legislation suggest that CCS technologies will not be widely deployed in the next two decades absent financial incentives that supplement projected carbon prices. In addition to the challenges associated with cost, these projects will need to meet regulatory requirements that are currently under development. Long-standing regulatory programs are being adapted to meet the circumstances of CCS, but limited experience and institutional capacity at the Federal and State[1] level may hinder implementation of CCS-specific requirements. Key legal issues, such as long-term liability and property rights, also need resolution.

A climate policy designed to reduce our Nation's GHG emissions is the most important step for commercial deployment of low-carbon technologies such as CCS, because it will create a stable, long-term framework for private investments. A concerted effort to properly address financial, economic, technological, legal, institutional, and social barriers will enable CCS to be a viable climate change mitigation option that can over time play an important role in reducing the overall cost of meeting domestic and global emissions reduction targets. Federal and State agencies can use existing authorities and programs to begin addressing these barriers while ensuring appropriate safeguards are in place to protect the environment and public health and safety.

Status of CCS Technologies

CCS is a three-step process that includes capture and compression of CO_2 from power plants or industrial sources; transport of the captured CO_2 (usually in pipelines); and storage of that CO_2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams. Technologies exist for all three components of CCS.

- Capture of CO_2 from industrial gas streams has occurred since the 1930s using a variety of approaches to separate CO_2 from other gases. These processes have been used in the natural gas industry and to produce food and chemical-grade CO_2. Existing capture technologies are energy-intensive, and consequently their application to coal-fired power plants and other industrial sources is expensive.

- The history of transporting CO_2 via pipelines in the United States spans nearly 40 years. Approximately 50 million tonnes of CO_2 are transported each year in the United States through 3,600 miles of existing CO_2 pipelines.

[1] References to "States" also include Tribal governments.

- Globally, there are four commercial CCS facilities sequestering captured CO_2 into deep geologic formations and applying a suite of technologies to monitor and verify that the CO_2 remains sequestered.[2,3] These four sites represent 25 years of cumulative experience on safely and effectively storing anthropogenic CO_2 in appropriate deep geologic formations (Dooley et al., 2009). DOE estimates that there are hundreds to thousands of years of storage potential in similar geologic formations in North America (NETL, 2008). Similarly, the Department of the Interior's U.S. Geological Survey (USGS) is leveraging DOE's efforts to generate a comprehensive catalogue of national sequestration potential.

Though CCS technologies exist, "scaling up" these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges. In the electricity sector, estimates of the incremental costs of new coal-fired plants with CCS relative to new conventional coal-fired plants typically range from $60 to $95 per tonne of CO_2 avoided (DOE, 2010a). Approximately 70–90 percent of that cost is associated with capture and compression. Some of this cost could be offset by the use of CO_2 for EOR for which there is an existing market, but EOR options may not be available for many projects.

Research, development, and demonstration (RD&D) programs such as those currently being conducted by DOE can help reduce project uncertainty and improve technology cost and performance. The focus of CCS RD&D is twofold: 1) to demonstrate the operation of current CCS technologies integrated at an appropriate scale to prove safe and reliable capture and storage; and 2) to develop improved CO_2 capture component technologies and advanced power generation technologies to significantly reduce the cost of CCS, to facilitate widespread cost-effective deployment after 2020.

Status of CCS in the United States

The Federal government is already pursuing a set of concrete initiatives to speed the commercial development of safe, affordable, and broadly deployable CCS technologies in the United States, including: RD&D of CCS technologies; the development of regulations that address the safety, efficacy, and environmental soundness of injecting and storing carbon dioxide underground; and the assessment of the country's geologic capacity to store carbon dioxide. All of this work builds on the firm scientific basis that now exists for the viability of CCS technology.

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[2] Since the 1970s, engineered injection of CO_2 into geologic reservoirs has taken place for purposes of enhanced oil recovery, resulting in the development of many aspects of reservoir management and operation needed for safe large-scale injection and geologic storage of CO_2.

[3] Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

Long-term integrated testing and validation programs are needed for technical, economic, and regulatory reasons. DOE is currently pursuing multiple demonstration projects using $3.4 billion of available budgetary resources from the American Recovery and Reinvestment Act[4] in addition to prior year appropriations. Various other incentives, such as tax credits and loan guarantees, are also available to many projects.

Up to ten integrated CCS demonstration projects supported by DOE are intended to begin operation by 2016 in the United States. These demonstrations will integrate current CCS technologies with commercial-scale power and industrial plants to prove that they can be permitted and operated safely and reliably. New power plant applications will focus on integrating pre-combustion CO_2 capture, transport, and storage with Integrated Gasification Combined Cycle (IGCC) technology. Power plant retrofit and industrial applications will demonstrate integrated post-combustion capture. These projects, plus others supported by Federal loan guarantees, tax incentives, and State-level drivers, cover a large group of potential CCS options. However, some proposed demonstration projects may not proceed for economic or other reasons. Looking toward long-term deployment, additional actions may be required to help overcome the uncertainty of evolving climate change policy and the high cost of applying currently available CCS technology, consistent with addressing market failures.

Barriers to CCS Deployment

The lack of comprehensive climate change legislation is the key barrier to CCS deployment. Without a carbon price and appropriate financial incentives for new technologies, there is no stable framework for investment in low-carbon technologies such as CCS. Significant Federal incentives for early deployment of CCS are in place, including RD&D efforts to push CCS technology development, and market-pull mechanisms such as tax credits and loan guarantees. However, many of these projects are being planned by the private sector in anticipation of requirements to reduce GHG emissions, and the foremost economic challenge to these projects is ongoing policy uncertainty regarding the value of GHG emissions reductions.

Even with financial support, challenges such as legal and regulatory uncertainty can hinder the development of CCS projects. Regulatory uncertainty has been widely identified as a barrier to CCS deployment. Though early CCS projects can proceed under existing laws, there is limited experience at the Federal and State levels in applying the regulatory framework to CCS. Ongoing EPA efforts will clarify the existing regulatory framework by developing requirements tailored for CCS, which will reduce uncertainty for early projects and help to ensure safe and effective deployment. Experience gained from regulating and permitting the first five to ten CCS projects will further inform potential changes to existing requirements and the need for an enhanced regulatory framework for widespread CCS deployment.

[4] Public Law 111-5.

The Task Force identified a range of views concerning potential long-term liabilities (i.e., those arising after closure of a CO_2 storage site) and the extent of any potential impacts on widespread deployment. Many States planning CCS projects are taking steps to address long-term liabilities associated with geologic storage of CO_2. The Task Force's preliminary assessment is that the existing Federal and State legal framework should be adequate for at least an initial group of five to ten commercial-scale projects. However, because of divergent views on the topic and limited time to analyze a complex set of underlying issues and drivers, additional analysis is needed to determine the most appropriate legal or regulatory structures for addressing potential long-term liabilities associated with widespread deployment.

Aggregation of pore space and associated property rights are also important for CCS projects. Historically, pore space issues have been handled by States. Several States are taking actions to address aggregation of pore space for geologic storage on private lands. Based on experience thus far, the Task Force believes States are best positioned to address pore space issues on private lands.

Public awareness and support are critical to the development of new energy technologies and are widely viewed as vital for CCS projects (IPCC, 2005; CRS, 2008; IEA, 2009c). Whether the public will support or oppose commercial-scale CCS projects is largely unknown (Malone et al., 2010), and the public's reaction may be project-specific. However, enhanced and coordinated public outreach will improve awareness of the role of CCS as one option to reduce GHG emissions. Integration of public information, education, and outreach efforts throughout the lifecycle of CCS projects will help identify key issues, foster public understanding, and build trust between communities and project developers.

Proposed Plan to Overcome Barriers

Support for Technology Development

To foster the success of early CCS projects, including five to ten commercial-scale demonstrations by 2016, DOE and EPA should create a Federal agency roundtable to act as a single point of contact for project developers seeking assistance to overcome financial, technical, regulatory, and social barriers facing planned or existing projects. As needed, this roundtable should provide technical support to State and Federal permitting authorities and permit applicants. This roundtable should also create a technical committee composed of experts from the power and industrial sectors, NGOs, State officials, and research community. Together with DOE and EPA, the technical committee would conduct a periodic review of CCS demonstration projects to track their progress and, broadly, identify any additional research, risk management, or regulatory needs. The technical committee could also, as requested by DOE or EPA, provide input on a range of CCS technical, economic, or policy issues.

DOE should continually review the adequacy of capture technologies and classes of storage reservoirs to enable safe and cost-effective widespread CCS deployment within ten years. This ongoing assessment, coupled with input from the technical committee outlined above, will assist the Administration in targeting any remaining technology gaps.

Increased Federal coordination would enhance the government's ability to assist these projects by providing more effective incentives and/or addressing barriers. DOE, in coordination with EPA, Treasury, and USDA, should track the use and efficacy of Federal financial support for CCS projects. Increased coordination will enhance the government's ability to tailor Federal funding and assistance to each project's market context, improve the clarity of eligibility criteria for projects to receive Federal support, allocate resources efficiently, and enable the Administration to more effectively consult with Congress and the States on the efficacy of existing incentives.

The Administration should continue to support international collaboration that complements domestic CCS efforts and facilitates the global deployment of CCS. Most CCS technology RD&D is being supported by the United States and other developed countries. Leveraging resources and sharing results across these countries will improve the viability of CCS and potentially speed up global commercialization. Energy and economic modeling suggests that CCS in coal-dependent emerging economies plays a key role under some future policy and economic scenarios in achieving global climate change mitigation goals. The United States should continue its cooperation with large coal-dependent emerging economies with rapidly expanding power sectors, to facilitate a constructive dialogue and help to avert the locking in of inefficient, high-GHG emission power generation assets for decades. Failure to do so may make subsequent CCS deployment more difficult and increase the cost of global climate change mitigation.

Providing Legal & Regulatory Clarity and Support

Federal agencies must work together to design requirements for CCS using existing authorities in complementary ways. By late 2010, EPA should finalize rulemakings for geologic sequestration wells under the Safe Drinking Water Act (SDWA) and GHG reporting for CO_2 storage facilities under the Clean Air Act (CAA), and propose a Resource Conservation and Recovery Act (RCRA) applicability rule for CO_2 that is captured from an emission source for purposes of sequestration. EPA guidance to support implementation of these rules should also be provided at the same time. By late 2011, EPA should finalize the RCRA applicability rule. EPA and the Department of the Interior (DOI) should immediately formalize coordination and prepare a strategy to develop regulatory frameworks for CCS for onshore and offshore Federal lands. Ratification of the London Protocol (LP) and associated amendment of the Marine Protection, Research, and Sanctuaries Act (MPRSA) as well as amendment of the Outer Continental Shelf Lands Act (OCSLA) will ensure a comprehensive statutory framework for the storage of CO_2 on the outer continental shelf.

Federal and State agencies must work together to enhance regulatory and technical capacity for safe and effective CCS deployment. Specifically, EPA, in coordination with DOE, DOI, and State agencies, should develop capacity-building programs for underground injection control regulators. Educating permit writers and other key officials will greatly enhance their capability and efficiency in issuing and enforcing technically sound permits. These programs should leverage existing efforts such as the DOE Regional Carbon Sequestration Partnerships (RCSPs). DOE and EPA should also identify data needs and tools to support regulatory development, permitting, and project development.

The Task Force emphasizes that appropriate monitoring, oversight, and accountability for CCS activities will be essential to ensure the integrity of CCS operations, enable a sustainable CCS industry, and provide a strong foundation for public confidence. DOE and EPA, in consultation with other agencies, should track regulatory implementation for early commercial CCS demonstration projects and consider whether additional statutory revisions are needed. This will enable the Administration to more effectively consult with Congress and the States if the existing framework proves ineffective.

Federal agencies should begin to develop National Environmental and Policy Act (NEPA) analyses related to CCS as early as possible to help ensure timely completion of robust and comprehensive environmental reviews. Where appropriate to Federal agency decision-making, agencies should consider development of Programmatic Environmental Impact Statements for use in tiered NEPA analysis and initiate this process. CEQ should consider development of CCS-specific NEPA guidance.

Efforts to improve long-term liability and stewardship frameworks should continue. By late 2011, EPA, DOE, Department of Justice (DOJ), DOI, and Treasury should further evaluate and provide recommendations to address long-term liability and stewardship in the context of existing and planned regulatory frameworks. Of the seven options identified by the Task Force, the following four approaches, or combinations thereof, should be considered: (1) reliance on the existing framework for long-term liability and stewardship; (2) adoption of substantive or procedural limitations on claims; (3) creation of an industry-financed trust fund to support long-term stewardship activities and compensate parties for various types and forms of losses or damages that occur after site closure; and (4) transfer of liability to the Federal government after site closure (with certain contingencies). Open-ended Federal indemnification should not be used to address long-term liabilities associated with CO_2 storage.

Public Outreach

To enhance and coordinate public outreach for CCS, DOE and EPA should leverage existing efforts to coordinate among Federal agencies, States, industry, and NGOs to gather information and evaluate potential key concerns around CCS in different areas of the United States. Using this information, DOE and EPA should develop a comprehensive outreach strategy among the

Federal government, States, industry, and NGOs having two components: a broad strategy for public outreach, targeted at the general public and decision makers, and a more focused engagement with communities that are candidates for CCS projects, to address issues such as environmental justice. A first step should be to immediately establish a clearinghouse for public access to unbiased, high-quality information on CCS. Over time, outreach tools should be developed for project developers and regulators with input from DOE, EPA, Department of Transportation (DOT), and DOI.

Conclusion

CCS can play an important role in domestic GHG emissions reductions while preserving the option of using abundant domestic fossil energy resources. However, barriers hamper near-term and long-term demonstration and deployment of CCS technology. While the largest of these barriers is the absence of a Federal policy to reduce GHG emissions, the Task Force has outlined specific actions the Federal government could take under existing authority and resources to address these barriers. For widespread cost-effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship. Timely development of cost-effective CCS could reduce the costs of achieving our Nation's climate change goals.

CCS can also play a major role in reducing GHG emissions globally. Continued leadership to develop and deploy CCS technologies as one option to address global climate change will position the United States as a leader in climate change technologies and markets. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available at economically competitive prices and supportive national policy frameworks are in place.

I. Background

On February 3, 2010, President Obama sent a memorandum to the heads of 14 Executive Departments and Federal Agencies establishing an Interagency Task Force on Carbon Capture and Storage (CCS). Representatives from the following Federal Agencies and Executive Departments participated in the Task Force: Department of State, Department of the Treasury, Department of Justice, Department of the Interior, Department of Agriculture, Department of Commerce, Department of Labor, Department of Transportation, Department of Energy, Office of Management and Budget, Environmental Protection Agency, Federal Energy Regulatory Commission, Office of Science and Technology Policy, and Council on Environmental Quality.

The goal was to develop a comprehensive and coordinated Federal strategy to speed the commercial development and deployment of carbon capture and storage technologies in line with the Administration's goals for climate protection. The Task Force, co-chaired by the Department of Energy and the Environmental Protection Agency, was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016.

In his memorandum, the President requested that within 180 days the Task Force explore incentives for commercial CCS adoption and address any financial, economic, technological, legal, institutional, social, or other barriers to deployment. The Task Force was to consider how best to coordinate existing administrative authorities and programs, including those that build international collaboration on CCS, as well as identify areas where additional administrative authority could be necessary.

Under the joint leadership of the Department of Energy and the Environmental Protection Agency, the Task Force was assembled, comprising over 100 Federal employees from multiple Federal agencies. The Task Force examined challenges facing early CCS projects as well as factors that could inhibit widespread commercial deployment of CCS. In developing the findings and recommendations outlined in this report, the Task Force relied on published literature and individual input from over 100 experts and stakeholders from the research community, States, environmental organizations, industry, and business groups, as well as public comments submitted to the Task Force.

Engaging the public in an open, transparent fashion was an important element of the Task Force's work. The Task Force's comprehensive outreach included a website hosted by the Council on Environmental Quality which included information about the Task Force, its meetings, and a mechanism for submitting public comments. The Task Force held an open public meeting on May 6, 2010, in Washington, D.C., which was simultaneously webcast. Over 200 people attended the meeting and 200 more watched online. The meeting included several panels of experts on various components of CCS systems and opportunity for public input and questions. The video, expert presentations, and meeting transcript were posted on the website.

The Task Force also met with individual groups, companies, and organizations who asked to provide input. Task Force staff held a series of targeted meetings with representative groups of stakeholders, including environmental organizations, labor organizations, State governments (including representatives from 14 governors' offices), the coal sector, and the oil/gas sector. The Task Force held a briefing on Capitol Hill and met with many Congressional staff from individual offices and committees to ensure their ideas and concerns were heard and addressed.

The Task Force recognizes the contributions of States in evaluating and beginning to address barriers to CCS deployment. States are supporting RD&D activities, developing regulatory frameworks, and providing incentives for CCS deployment. For example, several State universities are studying and assessing the potential for CCS. Some States have created task forces or directed State agencies or energy commissions to assess potential storage sites (both onshore and offshore) and develop reports with recommendations to accelerate CCS and address barriers to CCS.[5] In some cases, grant programs and trust funds have been used to support CCS research and development.[6] To address legal and regulatory barriers, some States have developed legislation to define jurisdiction for CO_2 injection,[7] designed regulations for injection wells,[8,9] established rules for permitting storage sites and CO_2 pipelines,[10] provided eminent domain powers for CCS development,[11] and developed laws related to liability[12] and property rights.[13]

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[5] See, for example, California AB 1925, 2006., Colorado HB 06-1322, 2006; Illinois HB 3854, 2009; Massachusetts HB 5018, 2008; Minnesota SF 2096, 2007; Oklahoma SB 1765, 2008 and SB 679, 2009; Texas SB 1387, 2009; Texas HB 1796, 2009; Pennsylvania HB 2200, 2008; and West Virginia HB 2860, 2009.

[6] See, for example: Illinois SB 1592, 2007; Louisiana HB 661, 2009; Massachusetts HB 5018, 2008; North Dakota SB 2095, 2009; and Texas HB 1796, 2009.

[7] Oklahoma SB 610, 2009 and Texas HB 1796, 2009.

[8] Kansas HB 2419, 2007; Washington Administrative Code 173-218-115; and West Virginia HB 2860, 2009; Wyoming HB 90, 2008.

[9] West Virginia HB 2860, 2009; Wyoming HB 90, 2008.

[10] West Virginia HB 2860, 2009; Wyoming HB 90, 2008; Utah Senate Bill 202, 2008; Indiana Code 8-1-22.5, 2009; South Dakota HB 1129; a HB 661, 2009; and Montana HB 24, 2007.

[11] Louisiana HB 661, 2009.

[12] North Dakota SB 2095, 2009; Illinois HB 1704, 2007; Louisiana HB 661, 2009; New Mexico Executive Order 2006-069; Utah SB 202; Wyoming HB 58; Kentucky HB 491; Michigan SB 775; New York AB 5836; Pennsylvania HB 80 2009; and Montana SB 498, 2009.

[13] Oklahoma SB 610, 2009; North Dakota SB 2139; Montana SB 498; Louisiana SB 1117; Texas HB 149; West Virginia SB 2860; Wyoming HB 57, 58, 80, 89, and 90; Michigan SB 775; New Mexico SB 145; and New York AB 5836 and 8802.

Several States are providing incentives for CCS deployment such as portfolio standards that include generation of electricity from power plants with CCS[14], alternative fuel standards,[15] emission standards,[16] prioritization of CCS during power plant permitting processes,[17] tax incentives (including tax exemption, reduced sales tax, taxation at lowered market value, tax credits),[18] and provision of full or partial cost recovery through authorized rate changes for power plants with CCS.[19]

In addition to specific individual actions, several States have formed regional partnerships for promoting CCS, including, for example, the Midwestern Energy Security and Climate Stewardship Platform,[20] the Midwestern Regional Greenhouse Gas Reduction Accord,[21] the Regional Greenhouse Gas Initiative (RGGI),[22] the Western Climate Initiative (WCI),[23] and the Western Governors' Association (WGA) Clean and Diversified Energy Initiative.[24]

The legislative agenda of the U.S. Congress continues to support to the development and deployment of CCS. In addition to provisions for CCS in the Energy Policy Act of 2005 and the 2009 American Recovery and Reinvestment Act (ARRA), five recent legislative proposals in the U.S. Congress include provisions related to CCS: American Power Act (APA) of 2010 -- Kerry-Lieberman[25]; S. 1462, American Clean Energy Leadership Act (ACELA) of 2009 -- Bingaman; S. 2877, Carbon Limits and Energy for America's Renewal (CLEAR) Act -- Cantwell-Collins; S. 3464, Practical Energy and Climate Plan (PECP) Act of 2010 -- Lugar, Graham & Murkowski; and H.R. 2454, American Clean Energy and Security Act (ACES Act) of 2009 -- Waxman-Markey. Although the approaches and specifics vary, most of the bills authorize funding for

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[14] Illinois SB 1987, 2009; Pennsylvania HB 80 2009; Ohio SB 21, 2008; and Massachusetts SB 2768, 2008.

[15] Pennsylvania HB 1202, 2007.

[16] California SB 1368, 2006; Illinois SB 1987, 2009; Maine LD 2126, 2008; Massachusetts SB 2768, 2008; Montana SB 25, 2007; Oregon SB 101, 2009; and Washington SB 6007, 2009.

[17] Illinois SB 1592, 2007; Rhode Island Code 42-98-2 and 42-98-3; and Montana HB 25, 2007.

[18] Kansas HB 2419, 2007; Mississippi HB 1459, 2009; Montana HB3, 2007; North Dakota HB 1365, 2007 and SB 2221, 2009; Colorado HB 06-1281, 2006; Florida HB 549, 2007; Kentucky HB 1, 2007; New Mexico SB 994, 2007; Wyoming HB 61, 2006; Michigan HB 4016, 2009; and Texas HB 469, 2009 and HB 3732, 2007.

[19] Arkansas HB 2812, 2007; Colorado HB 06-1281, 2006; Florida HB 549, 2007; New Mexico SB 994, 2007; Virginia SB 1416, 2007; and West Virginia Code 24-2-1g.

[20] Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin, and the Canadian Province of Manitoba.

[21] Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin, and the Premier of the Canadian Province of Manitoba.

[22] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

[23] Arizona, California, New Mexico, Oregon, and Washington.

[24] California, New Mexico, North Dakota, Utah, and Wyoming.

[25] Discussion draft released on May 12, 2010.

development and demonstration of CCS technologies, create incentives for commercial deployment of CCS, and address legal and regulatory issues (CRS, 2010). For example, the ACELA authorizes funding for up to 10 CCS demonstration projects through a competitive selection process[26] and the ACES Act and the APA would establish a CCS fund to finance either the first five[27] or the first 10 GW[28] of commercial-scale demonstration projects (CRS, 2010; Pew, 2010b; Pew, 2010a; Pew, 2010c; Pew, 2010d; Pew, 2010e).[29]

Beyond these bills, several different amendments and legislative proposals have been introduced over the past few years supporting CCS development and deployment. For example, Senators Rockefeller and Voinovich introduced legislation in March 2010 to promote research and create incentives to develop and deploy full scale CCS. Congressman Boucher introduced legislation in 2009 to establish a $1 billion annual fund, derived from fees on the generation of electricity from coal, oil and natural gas, to provide grants to large-scale projects advancing the commercial availability of CCS technology. Senator Boxer introduced an amendment in 2008 to the Lieberman-Warner Climate Security Act establishing a long-term incentives and legal framework for CCS. Senator Barasso introduced an amendment in 2009 to clarify that the Federal government owns the pore space below Federal land. Senators Casey and Enzi introduced a bill for creating a framework for addressing legal and financial responsibilities for commercial carbon storage operations.

Other legislators have voiced support for CCS and facilitated stakeholder discussions on promoting CCS as a technology critical to the continued use of coal in a carbon constrained future.[30] For example, Senator Dorgan established a Clean Coal and CCS Technology Initiative in the fall of 2009 to facilitate discussion on promoting CCS.[31]

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[26] S. 1462/ACELA would authorize funding for the DOE to support up to 10 CCS demonstration projects for large-scale integrated capture and sequestration of CO_2 from industrial sources (including power plants).

[27] H.R. 2454/Waxman-Markey would authorize financial support to at least five commercial-scale CCS demonstration projects, pending approval by the States.

[28] APA/Kerry-Lieberman would authorize a special funding program to support CCS projects that result in the capture of CO_2 emissions from at least 10 GW and would only be available for fossil-fueled electric generation projects of at least 100 MW, with at least 80 percent of funds awarded going to projects of at least 300 MW.

[29]The proposed CCS fund would be financed through a charge to electric utilities burning fossil fuels based on the carbon content of each fuel. This charge would be highest for coal and lowest for natural gas.

[30]See, for example, statements by Congressman Rahall and Senator Byrd http://www.rahall.house.gov/index.cfm?sectionid=10&parentid=5&sectiontree=5,10&itemid=981; http://byrd.senate.gov/mediacenter/view_article.cfm?ID=525.

[31] http://dorgan.senate.gov/issues/energy/cleancoal/index.cfm.

II. Role of CCS in Administration Climate Policy & Global Initiatives

As one of relatively few low-carbon electricity generation technologies, carbon capture and storage (CCS) could play an important role in achieving national and global greenhouse gas (GHG) reduction goals, and its commercial availability could broaden the options available to achieve those goals. For example, the American Clean Energy Security Act and the American Power Act are estimated to induce about 30 percent of fossil-fuel-based electricity generation to come from power plants with CCS by 2040, rising to approximately 59 percent by 2050 (15 percent and 16 percent respectively of total electricity generation) (EPA, 2010).

The Administration is committed to a range of policies that address the market failures that would otherwise impede the deployment of low-carbon technologies such as CCS. Examples of such policies include putting a price on carbon, tax incentives, and investments in research, development, and demonstration (RD&D). Private firms tend to under invest in research since they cannot capture the full social value of their investments, so there is a strong rationale for government policy to support technology-neutral RD&D[32]. Investments in RD&D may bring a technology closer to deployment by reducing uncertainty related to cost or performance, thereby enabling its commercial viability.

To jump-start the transition to a low-carbon economy, the Administration provided roughly $60 billion in direct spending and $30 billion in tax credits through the American Recovery and Reinvestment Act of 2009 (ARRA). These investments were chosen carefully to support a broad spectrum of low-carbon-related activities. In particular, ARRA authorized $3.4 billion to support CCS RD&D initiatives that range from analysis of the sequestration[33] potential of geologic formations to public-private cost-shared demonstrations of advanced CCS technologies.

Globally, CCS can play a major role in reducing GHG emissions, with 20–40 percent of global CO_2 emissions in 2050 projected to be suitable for capture—including 30–60 percent of all emissions from electric power (IPCC, 2005). The early development of a robust domestic industry in advanced CCS technology would further the Administration's goals for continued leadership in the global market for innovation. American firms could become leading exporters of advanced CCS technology. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available and a supportive national policy framework is in place. Global partnerships are now working to address these challenges.

[32] See IV.A.3 for more on knowledge spillovers from research and development of CCS Technology.

[33] "CO_2 sequestration", "geologic sequestration", and "CO_2 storage" are used synonymously in this report.

II.A Projected Scale of CCS in U.S. Climate Policy

The timing and scale of CCS deployment are dependent on a carbon price and any other financial incentives for low-carbon technology, as well as the costs of CCS relative to other technologies. Figure II-1 shows carbon prices in the modeling of legislation with emissions targets that are largely consistent with the Administration's climate change goals.[34,35] In the base case, allowance prices in 2020 are $24 and $31 per tonne CO_2 equivalent[36] (CO_2e) for the U.S. Environmental Protection Agency (EPA) and the U.S. Energy Information Administration (EIA) analyses, respectively. If international offsets are unavailable or not allowed in the program, carbon prices are higher, at $52 per tonne CO_2e for both the EPA and EIA analyses. Finally, if international offsets are unavailable, nuclear and dedicated biomass electricity generation are unavailable beyond business-as-usual levels, and CCS deployments are limited[37], allowance prices rise to $59 - $89 per tonne CO_2e in 2020 (EPA 2010; EIA 2010). These results reinforce the concept that availability of mitigation options (whether offsets or more cost-effective technologies) lowers the price of allowances, and thus the overall economic cost of averting climate change.

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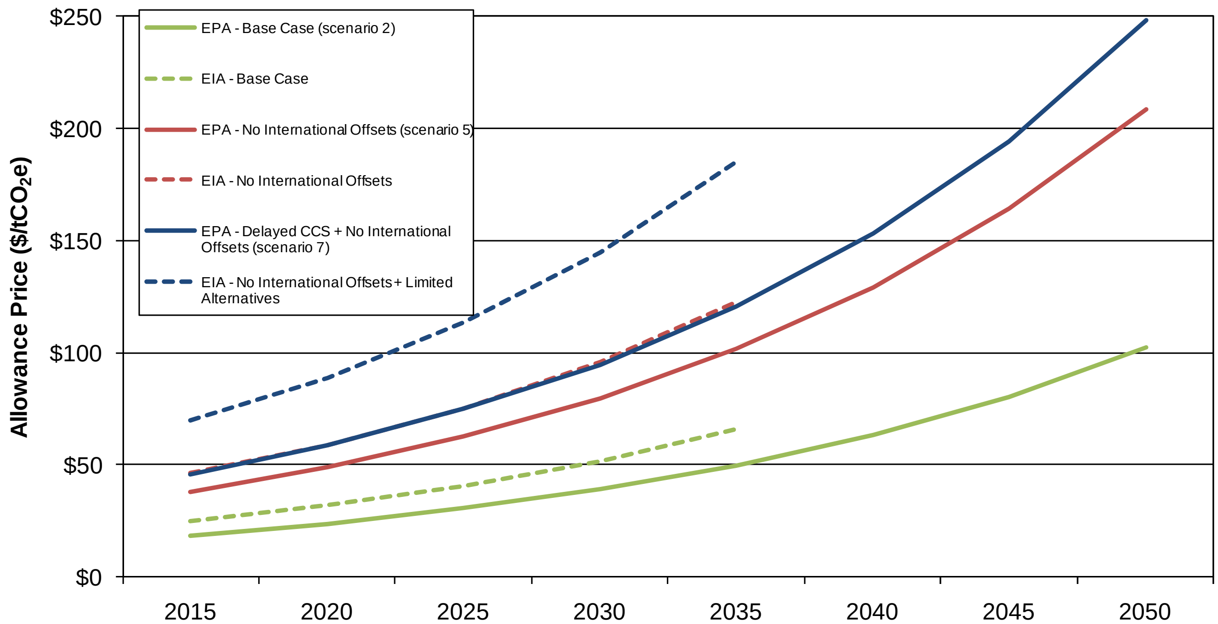
[34] Analyses by EPA and EIA of climate proposals consistent with the President's GHG emission reduction goals of 17 percent by 2020 and 83 percent by 2050 from 2005 levels estimate the range of carbon prices that achieve the President's emission reduction goals, the cost to the United States economy of achieving such reductions, and the role that CCS is projected to play in transforming the way we consume and produce energy.

[35] As with all models of the energy economy, the outputs are based on a set of assumptions regarding economic growth, energy demand, resource availability, and the long-run cost of producing energy using various technologies. Each model incorporates improvements in technology characteristics over time, in this case extending from 20 to 40 years into the future. Modeling assumptions vary among analyses. For example, CCS retrofits are not explicitly modeled in these analyses. These studies are widely recognized and respected in the climate policy discussion.

[36] CO_2 equivalent is a measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP). CO_2 equivalent for a gas is derived by multiplying the tonnes of the gas by the associated GWP. Tonne CO_2e = (tonne of a gas) * (GWP of the gas). The GWP of carbon dioxide is 1, by definition.

[37] EPA analysis of APA Scenario 7 assumes that CCS is not commercially available until after 2030.

Figure II-1 Range of Domestic Allowance Prices in Economic Modeling of Proposed Policy



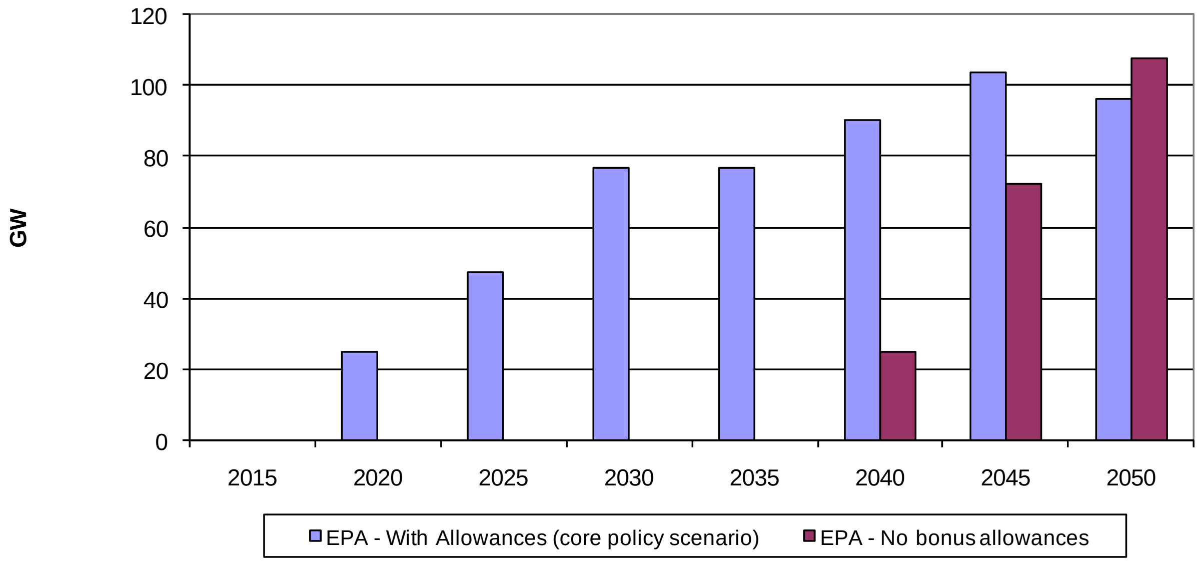
Source: EPA and EIA analyses of the American Power Act.

The policy shown above refers to a discussion draft (not yet introduced) of Senate legislation that includes bonus allowances to promote CCS deployment above and beyond what the market would support in response to a price on GHG emissions. To understand the effect of these bonus allowances,[38] EPA ran a comparison scenario without them. As Figure II-2 below shows, the bonus allowances are projected to shift CCS deployment 15–20 years ahead of when it would deploy in their absence.

However, it is necessary to understand the broader implications of using additional financial incentives, such as bonus allowances, to promote earlier CCS deployment. The bonus allowances encourage firms to invest in CCS even though there are less costly means of achieving emissions reductions that do not receive bonus allowances. To the extent that such additional financial incentives distort the efficiency of the market, the overall economic cost of meeting the carbon target would be expected to rise. As with any technology, the increase in overall economic cost due to early deployment incentives would be reduced to the extent that early deployment lowers technical and commercial risk and enables CCS technology improvements that lower the cost of later widescale deployment.

[38] Recent legislative proposals for GHG cap-and-trade systems have reserved a share of emission allowances for free allocation to CCS applications. Bonus allowances are discussed in detail in Section V.D.3.

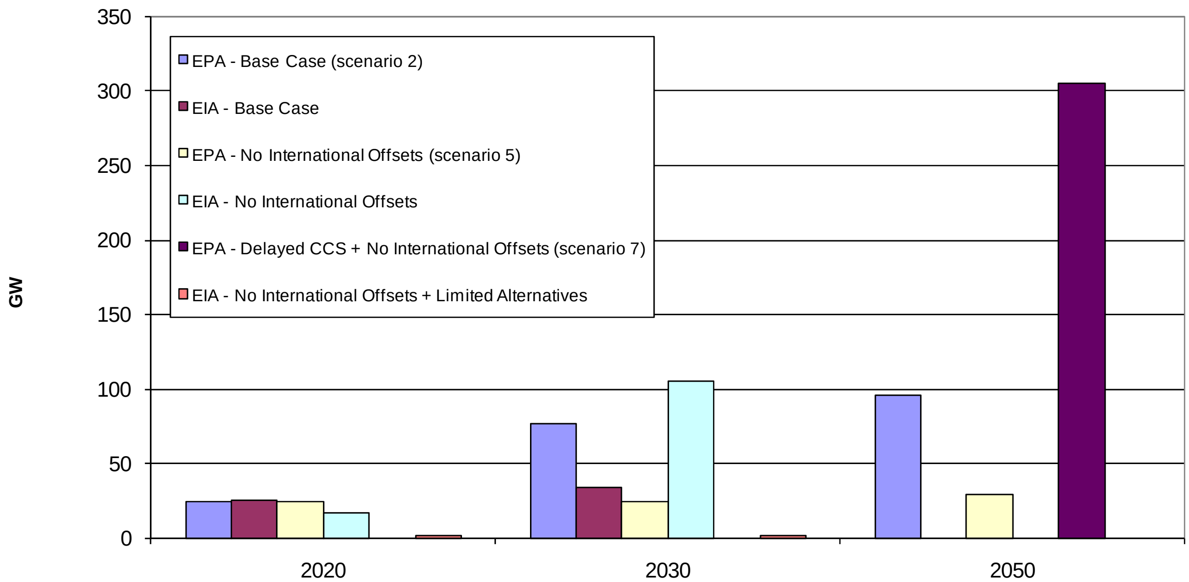
Figure II-2 CCS Deployment (GW) EPA Modeling of Proposed Policy



Source: EPA (2010)

Figure II-3 shows the projected deployment of CCS as a result of the legislation under several different scenarios that were modeled by EPA and EIA. Consistent with the previous discussion, the bonus allowance provisions would drive deployment through 2030 in the cases where CCS technology is not delayed. The availability of international offsets does not significantly change the impact of bonus allowances on CCS deployment. However, by 2050, CCS deploys economically and in greater quantities in the "no international offset" scenarios due to higher allowance prices (i.e., more reductions must occur domestically and these have higher costs associated with them than opportunities available internationally). These scenarios provide reasonable bounds on the expected range of CCS deployment under a climate policy that caps emissions.

Figure II-3 CCS (GW) EPA and EIA Modeling of Proposed Policy[39]



Source: (EIA, 2010; EPA, 2010). Note: EIA analysis only extends to 2035 and therefore is not shown for 2050. CO_2 captured assumed to be 90 percent. A typical 550MW net output coal-fired power plant capturing 90 percent of the CO_2 would capture about 5 million tonnes of CO_2 per year.

These modeling exercises show that CCS may play an important role in helping the United States meet carbon reduction targets. The key to broad, cost-effective, commercial deployment of CCS is a climate policy that provides the right incentives to produce low-carbon energy, along with policies to promote RD&D in CCS and other potential low-carbon technologies. However, even with appropriate market signals from comprehensive energy and climate policy, non-economic barriers could prevent projected CCS deployment. To the extent that legal, regulatory, social, and economic barriers hinder the availability of CCS as a mitigation option, they would raise the overall cost of meeting the Administration's climate goals. Thus, the Administration is committed to addressing these barriers to deployment.

II.B Role of CCS in Global Climate Strategy

Key insights into the value of international deployment of low-carbon technologies as part of a global climate strategy can be gleaned from a series of papers published in Energy Economics

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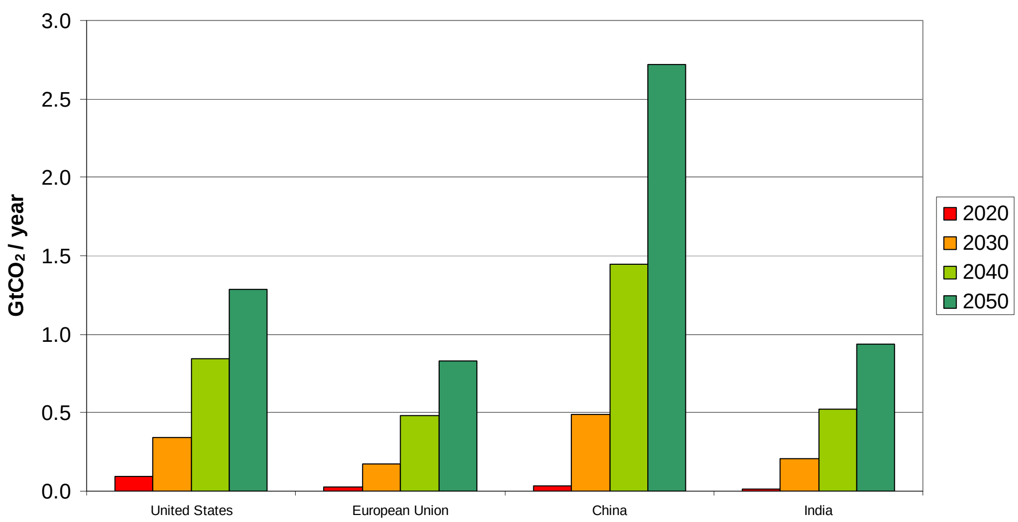
[39] Prohibiting international offsets from entering the American Power Act emissions reduction program in EPA scenario 5 increases allowance prices and forces greater amounts of GHG abatement to occur in covered sectors, including the power sector. CCS deployment is actually lower in scenario 5 than in scenario 2. With high allowance prices in scenario 5, the small amount of GHG emissions from CCS, which is assumed to have 90% capture efficiency, make nuclear the preferred option in the ADAGE model. Given the joint constraint in ADAGE on nuclear and CCS, as nuclear increases in scenario 5 relative to scenario 2, CCS decreases to stay within the model constraint.

(see Clarke et al., 2009 for an overview). These papers summarize the results from the Stanford Energy Modeling Forum EMF-22 exercise, which included ten of the world's leading integrated climate assessment models (models with detailed representations of the energy sector that explicitly include GHG emissions and climate feedbacks).

Figure II-4 shows selected results for the full global participation case in which a 550 ppm CO_2 concentration target is not exceeded.[40] It shows the amount of CO_2 averaged across all the models that is projected to be captured and stored by four major participants (the United States, European Union, China, and India). The message is relatively straightforward: a policy framework for global GHG emissions reductions will create a price signal that has the potential to drive commercial deployment of CCS absent additional barriers. However, such rapid deployment will require careful attention to any non-economic barriers not captured in the models. In addition to domestic efforts, the Administration is committed to continuing its engagement with other nations as described in Sections V and VI.

Figure II-4 Projected CO_2 Sequestration for Four Major Participants in a Global Regime



The technical potential to deploy CCS in a given country or region is dictated by the availability of suitably large, secure geologic reservoirs. Many developed countries, including the United States, are collecting information about the availability of such reservoirs. However, emerging economies generally lack the resources and expertise to acquire the information needed for detailed assessments with a high degree of confidence. In some countries, the information currently available is not sufficiently detailed to determine whether CCS could be considered as a climate change mitigation option. Additional detailed assessments of geologic formations are

[40] This concentration target corresponds to roughly a 3 degree Celsius increase in long-run global mean temperature relative to pre-industrial levels (IPCC, Fourth Assessment Report).

necessary to develop commercial-scale CCS projects. The United States, along with several other developed countries, is providing technical assistance to emerging economies (China, in particular) on their initial geologic sequestration assessments through a variety of development assistance and cooperative RD&D programs.

The 2nd edition of the *Carbon Sequestration Atlas of the United States and Canada* (Atlas II) is a good example of the type of data needed to assess the technical potential to deploy CCS in a given country or region (NETL, 2008). This atlas provides a comprehensive update of CCS potential across the majority of the United States and portions of Canada. It also presents updated information on the location of stationary CO_2 emission sources and the locations and sequestration potential of various geologic sequestration sites, and provides information about the commercialization opportunities for CCS technologies. The USGS is leveraging DOE's efforts to generate a comprehensive catalogue of national sequestration potential, using their recently finalized methodology to assess CCS resources in the United States.

In addition to the U.S. efforts, Australia, China, Japan, and European countries are currently publishing data on their geologic storage potential. However, there is no single reference at sufficient detail for the rest of the world. Global capacity estimates use simplistic methods and assumptions and therefore have considerable uncertainty (IPCC, 2005). In contrast, country estimates, such as those reported in the Atlas II for the United States and Canada, are generated regionally using consistent methodologies and assumptions, making them more reliable.

International partnerships have been formed to address the various challenges associated with widescale global CCS deployment, as described further in Section V.C.3. These partnerships offer the opportunity for countries to share their knowledge and experience gained from early efforts to deploy CCS technology. The important role that CCS can play in transitioning to a low-carbon global economy was also highlighted in the June 2010 G8 declaration, which noted that the G8 welcomes "the progress already made on our Toyako commitments to launch the 20 large-scale CCS demonstration projects globally by 2010 and to achieve the broad deployment of CCS by 2020, in cooperation with developing countries. Several of us commit to accelerate the CCS demonstration projects and set a goal to achieve their full implementation by 2015."[41] Such efforts may play an important role in enabling CCS to become a key technology option in efforts to reduce global CO_2 emissions.

[41] Page 7, paragraph 24 of G8 text at http://www.whitehouse.gov/sites/default/files/g8_muskoka_declaration.pdf.

III. State of CCS Technology

CCS is a three-step process that includes the capture of CO_2 from power plants or industrial sources, transport of the captured CO_2 (usually in pipelines), and storage of that CO_2 in suitable geologic reservoirs. Technologies exist for all three components of CCS, but they have not yet been deployed at the scale necessary to help achieve GHG reduction targets. Cost estimates of current technology for CCS in power production range between $60 and $114 per tonne of CO_2 avoided[42] depending on the power plant type (DOE, 2010a). Approximately 70–90 percent of that cost is associated with capture and compression. The subsections below describe the current state of technology development for capture, transport, and storage of CO_2. The small-scale CCS efforts that have been conducted to date are presented along with upcoming larger-scale demonstration projects.

III.A CO₂ Capture

III.A.1 Introduction

This section of the report presents a brief history of CO_2 capture technology, the current state of technology development, and planned large-scale demonstration projects. Additional supporting material can be found in Appendix A.

Although CO_2 capture is new to coal-based power generation, removal of CO_2 from industrial gas streams is not a new process. Gas absorption processes using chemical solvents to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2 from gas streams containing 3 to 25 percent CO_2 (see Appendix A, Figure A-1). In the 1950s and 1960s, gas adsorption processes were developed to separate CO_2 from gas streams associated with hydrogen (H_2) production (refineries), nitrogen (N_2) separation, and dehydration. In the 1970s and 1980s, gas separation membranes were developed for EOR (oil/gas separation) and natural gas processing applications (Kohl and Nielsen, 1997).

The licensing history of the Econamine FG process provides a good example of past applications of CO_2 removal technologies (Chapel et al., 1999). Prior to 1999, 25 facilities were built with CO_2 capture capacities ranging from 635 to 365,000 tonnes per year using this process (see Appendix A, Table A-1). Three were coal-fired applications capturing 600 to 1,600 tonnes of CO_2 per year. The captured CO_2 from these facilities was used for enhanced oil recovery (EOR), urea production, and in the food and beverage industry. The capture rates of

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[42] Note that these values are not the same as the emission allowance price at which CCS would become economically viable. Rather, as the incremental cost per tonne sequestered relative to the same technology without CCS, these values represent a lower bound on the allowance price above which CCS would become economic.

these facilities reflect the fact that they were built to serve a specific commercial market for CO_2. Other amine-based processes (e.g., ABB/Lummus) were implemented at similar capture rates during this period. By comparison, a single 550 megawatt (MW) net output coal-fired power plant capturing 90 percent of the emitted CO_2 will need to separate approximately 5 million tonnes of CO_2 per year. Scaling up these existing processes represents a significant technical challenge and a potential barrier to widespread commercial deployment in the near term (DOE, 2010a).

A 2009 review of commercially available CO_2 capture technologies identified 17 operating facilities using either chemical or physical capture solvents (see Appendix A, Table A-2) (Dooley et al., 2009). These included four natural gas processing operations and a syngas production facility in which more than 1 million tonnes of CO_2 are being captured per year. The largest (a natural gas processing operation in Wyoming) captures 3.6 million tonnes per year, similar to the volumes that can be expected from electricity generating plants. However, it is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed to facilitate widespread, cost-effective deployment of CO_2 capture.

III.A.2 Status of Capture Technology

III.A.2.1 Industrial Sectors

One-quarter of U.S. CO_2 emissions come from the industrial sector, with the highest emissions coming from petroleum refining, chemical production, cement production, pulp and paper, and iron and steel production. Few studies or demonstration projects have enabled the evaluation of the applicability of CO_2 capture technologies to these industrial sources. Some industrial facilities (e.g., lime production, petroleum refineries, natural gas processing, and ammonia plants) produce relatively concentrated CO_2 streams. As previously mentioned, scrubbers have been used at some of these industrial facilities, though at very small scale, to capture CO_2 for specific use, such as EOR. The CO_2 from many of these facilities could likely be captured at lower cost, as the CO_2 is often already separated as part of the industrial process and thus may require little additional processing. However, there are currently few incentives, either regulatory or economic, to capture GHG emissions from these industrial sources. As a consequence, few of the available technologies are being employed on a wide scale.

III.A.2.2 Coal-Fired Power Generation

In general, CO_2 capture technologies applicable to coal-fired power generation can be categorized into three approaches (IPCC, 2005; DOE, 2007):

- Pre-combustion systems are designed to separate CO_2 and H_2 in the high-pressure syngas produced at Integrated Gasification Combined Cycle (IGCC) power plants.
- Post-combustion systems are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air.
- Oxy-combustion uses high-purity oxygen (O_2), rather than air, to combust coal and therefore produces a highly concentrated CO_2 stream.

Each of these approaches results in increased capital and operating costs and decreased electricity output (or energy penalty[43]), thereby significantly increasing the cost of electricity (COE) (Rubin, 2008; DOE, 2010a). The energy penalty occurs because the CO_2 capture process uses some of the energy produced from the plant. The capture approaches and their impacts on COE and electricity production are summarized below.

Pre-Combustion CO_2 Capture

Pre-combustion capture is mainly applicable to IGCC plants, where fuel is converted into gaseous components ("syngas fuel") by applying heat under pressure in the presence of steam and limited O_2. The carbon contained in the syngas is captured before combustion and power production occur (see Appendix A, Figure A-2). The cost of electricity (COE) for an IGCC power plant without CCS is higher than that for a pulverized coal (PC) power plant. Using the Selexol™ process to capture CO_2 at an IGCC power plant increases the COE by approximately 40 percent relative to the same plant without a capture system.[44] By comparison, adding an amine scrubber to capture CO_2 from a PC power plant increases the COE by nearly 80 percent relative to the same plant without a capture system. The energy penalty for capturing and compressing 90 percent CO_2 in pre-combustion IGCC applications is approximately 20 percent (Rubin, 2008; Hamilton, 2009; DOE, 2010a).

Post-Combustion CO_2 Capture

Post-combustion CO_2 capture refers to removal of CO_2 from combustion flue gases prior to discharge to the atmosphere (see Appendix A, Figure A-4). Separating CO_2 from this flue gas is challenging for the following reasons:

- A high volume of gas must be treated because the CO_2 is dilute (13 to 15 percent by volume in coal-fired systems, three to four percent in natural-gas-fired systems);

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[43] The energy penalty represents the percentage reduction in the power plant operating efficiency. For example, a reduction in efficiency from 30 percent to 20 percent represents a 10 percentage point drop in efficiency, which is equivalent to a 33 percent energy penalty.

[44] The 30-year levelized costs are calculated in current (i.e., real) dollars using 2009 as the base year.

- the flue gas is at low pressure (near atmosphere); trace impurities (particulate matter [PM], sulfur oxides [SO_x], nitrogen oxides [NO_x], etc.) can degrade the CO_2 capture materials; and
- compressing captured CO_2 from near atmospheric pressure to pipeline pressure (about 2,000 pounds per square inch absolute) requires a large auxiliary power load (Rubin, 2008; Hamilton, 2009; Herzog, 2009; Herzog et al., 2009).

Post-combustion CO_2 capture offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be used to retrofit existing PC power plants. Although post-combustion capture technologies would typically be applied to conventional coal-fired power plants, they could also be applied to the flue gas from IGCC power plants, natural gas combined cycle (NGCC) power plants, and industrial facilities that combust fossil fuels. Currently, there are several commercially available solvent-based capture processes. In addition, a wide variety of processes employing solvents, solid sorbents, and membranes are at varying stages of development (EPRI, 2008; Ciferno et al., 2009).

Installing current amine post-combustion CO_2 capture technology on new conventional subcritical, supercritical, and ultra-supercritical coal-fired power plants would increase the COE by about 80 percent. Further, the large quantity of energy required to regenerate the amine solvent and compress the CO_2 to pipeline conditions would result in about a 30 percent energy penalty (DOE, 2010a).

Oxy-Combustion

Oxy-combustion systems for CO_2 capture rely on combusting coal or other fuels with relatively pure O_2 diluted with recycled CO_2 or CO_2/steam mixtures. Under these conditions, the primary products of combustion are water and CO_2, with the CO_2 purified by condensing the water (see Appendix A, Figure A-6) (Bohm, 2006; Hamilton, 2009; Herzog, 2009).

There are multiple technical and economic advantages of coal oxy-combustion that provide a high potential for a significant reduction in CO_2 capture costs compared with current state-of-the-art amine scrubbing. All critical components required for a commercial power plant are in operation today at scale, including cryogenic air separation units (ASU) and CO_2 purification and compression equipment. This corresponds to little or no equipment scale-up barriers. The technology components can be readily applied to new and existing coal-fired power plants and the removal of other criteria pollutants such as NO_x, SO_x, and mercury (Hg) is enhanced during the oxy-combustion process. Finally, significant cost reductions and efficiency improvements can be realized by incorporating advanced ultra-supercritical boiler materials and advanced CO_2 purification/compression.

However, first-mover oxy-combustion power plants come with a few key challenges, namely the capital cost and energy consumption for a cryogenic ASU to produce oxygen, boiler air infiltration (mainly N_2), and excess O_2 contaminating in the CO_2 sequestration stream. Construction of a new supercritical oxy-combustion coal-fired power plant equipped with a commercially available cryogenic ASU would increase the COE by about 60 percent and have a 25 percent energy penalty compared with a new supercritical air-fired, coal-based power plant without CO_2 capture (DOE, 2010a; DOE, 2010b).

III.A.2.3 CO_2 Capture Experience Associated with Power Production

Commercially available CO_2 capture technologies are currently being used in various industrial applications. However, one of the key barriers to their more widespread commercial deployment as a climate change mitigation strategy is the lack of experience with these systems at the appropriate scale in power plant settings (Kuuskraa, 2007). The following is a brief summary of currently operating CO_2 capture systems in coal-based power plant applications.

AES's coal-fired Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) power plants are equipped with amine scrubbers developed by ABB/Lummus. They were designed to process a relatively small percentage of each plant's flue gas. At Warrior Run, approximately 110,000 tonnes of CO_2 per year are captured, whereas at Shady Point 66,000 tonnes of CO_2 per year are captured. The CO_2 from both plants is subsequently used in the food processing industry (Dooley et al., 2009).

At the Searles Valley Minerals soda ash plant in Trona, California, approximately 270,000 tonnes of CO_2 per year are captured from the flue gas of a coal power plant via amine scrubbing and used for the carbonation of brine in the process of producing soda ash (IEA, 2009a; SourceWatch, 2009).

In September 2009, American Electric Power Co. (AEP) began operating the Alstom post-combustion chilled ammonia pilot process to capture 100,000 tonnes of CO_2 per year on the Mountaineer Plant in New Haven, West Virginia, and store it in deep geologic formations beneath the Mountaineer site.

A pre-combustion Rectisol® system is used for CO_2 capture at the Dakota Gasification Company's synthetic natural gas (SNG) production plant located in North Dakota, which is designed to remove approximately 1.6 million tonnes of CO_2 per year from the synthesis gas. The CO_2 is purified, transported via a 200-mile pipeline, and injected into the Weyburn oilfield in Saskatchewan, Canada. However, this experience is based on a gasification plant, not an IGCC power plant (Dakota Gasification Company, Undated).

Oxy-combustion of coal is being demonstrated in a 10 MWe facility in Germany. The Vattenfall plant in eastern Germany (Schwarze Pumpe) has been operating since September 2008. It is designed to capture 70,000 tonnes of CO_2 per year (Vattenfall, Undated).

III.A.3 Planned Demonstrations of CO_2 Capture Technologies

While the efforts described above are worthwhile and important in advancing CO_2 capture technologies, they still are not at a large enough scale to overcome technical uncertainty associated with scale-up needed for widespread cost-effective deployment. One means of addressing these uncertainties is through demonstration programs such as those currently being conducted by DOE.

DOE's Clean Coal Power Initiative (CCPI) is focused on accelerating availability of technologies for use by the private sector in new and existing coal-based power plants. CCPI is pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects using currently available technologies (see Appendix A, Table A-8).

The pre-combustion projects involve CO_2 capture from IGCC power plants. The specific projects include the following:

- Summit Texas Clean Energy: a 400 MW facility in west Texas burning Powder River Basin coal where 2.7 million tonnes per year of CO_2 will be captured using a Selexol™ process and used in an EOR application.
- Southern Company Kemper: a 582 MW facility in Mississippi burning Mississippi lignite where 1.8 million tonnes per year of CO_2 will be captured using a Selexol™ process and used in an EOR application.
- Hydrogen Energy California: a 257 MW facility in south-central California burning coal and petroleum coke where 1.8 million tonnes per year of CO_2 will be captured using a Rectisol® process and used in an EOR application.

The post-combustion projects will capture CO_2 from a portion of the PC plant's flue gas stream. The specific projects include the following:

- Basin Electric: amine-based capture of 900,000 tonnes per year of CO_2 from a 120 MW equivalent slipstream at a North Dakota plant for use in an EOR application and/or saline storage.
- NRG Energy: amine-based capture of 400,000 tonnes per year of CO_2 from a 60 MW equivalent slipstream at a Texas plant for use in an EOR application.
- American Electric Power: ammonia-based capture of 1.5 million tonnes per year of CO_2 from a 235 MW equivalent slipstream at a West Virginia plant for saline storage.

Similar to the CCPI projects, the FutureGen project will demonstrate carbon capture from a 200 MW advanced oxy-combustion unit in Meredosia, Illinois, integrated with CO_2 storage in

Mattoon, Illinois. FutureGen aims to capture and store at least one million tonnes of CO_2 per year.

In addition to the CCPI program, CO_2 capture demonstration projects are being conducted under the DOE Industrial Carbon Capture and Storage (ICCS) program (see Appendix A, Table A-9) (DOE, 2010c). These projects are pursuing capture technologies that are similar to those being demonstrated for power plants and are of similar magnitude to the CCPI demonstrations. Eleven projects were initially selected for the ICCS program. In June 2010 three projects were selected to move forward to full demonstrations. These include the following:

- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an EOR application.
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

The large-scale CO_2 capture demonstrations that are currently planned under DOE's initiatives will generate operational knowledge and enable future commercialization and widespread cost-effective deployment of these technologies. In addition to the selected projects, information has been compiled for 20 to 25 other domestic CCS efforts in various stages of development that could contribute to the deployment of CCS. Though it is unclear how many of these will move forward, they have the potential to contribute important additional information to future CCS development.

III.A.4 CO_2 Capture Cost

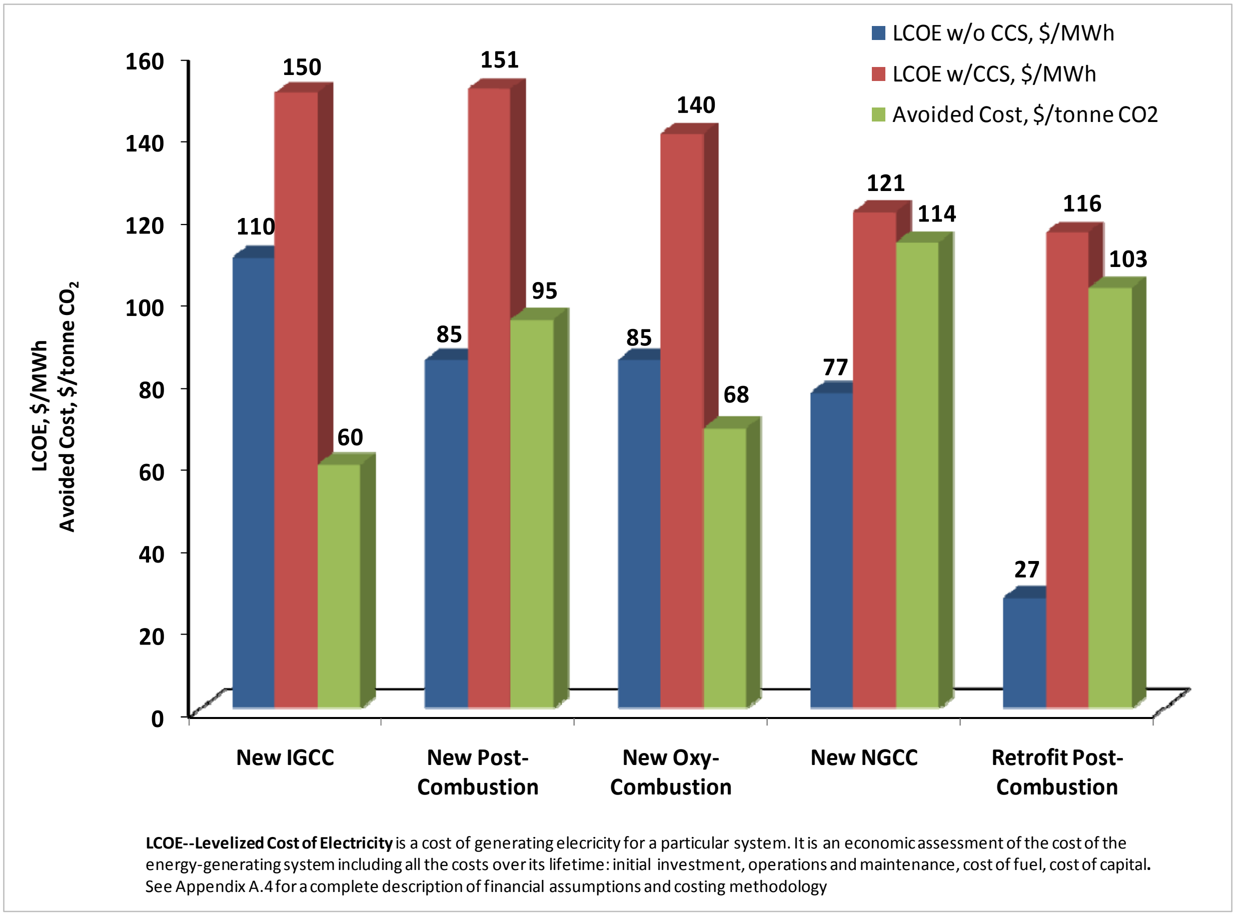
DOE analyses indicate that for a new 550 MWe net output power plant, addition of currently available pre-combustion CO_2 capture and compression technology increases the capital cost of an IGCC power plant by approximately $400 million (~25 percent) compared with the non-capture counterpart. For a similarly sized new supercritical PC plant, post-combustion and oxy-combustion capture would increase capital costs by approximately $900 million (80 percent) and $700 million (65 percent) respectively. For post-combustion CO_2 capture on a similarly sized new NGCC plant, the capital cost would increase by $340 million or 80 percent.

In terms of cost per tonne of CO_2 avoided, values range from $60/tonne for IGCC to $114/tonne for NGCC.[45] Figure III-1 shows the range of these costs for various types of power

[45] The dollar per tonne of CO_2 avoided is the incremental cost of CO_2 emissions avoided by applying CCS and is compared to a similar non-captured facility. It is calculated by dividing the difference in COE, $/MWh, by the difference in CO_2 emissions with and without CO_2 capture, tonnes/MWh. The dollar per tonne CO_2 captured is

plants (DOE, 2010a). In terms of cost per tonne of CO_2 captured, values range from \$49/tonne for IGCC to \$95/tonne for NGCC. Improvements to currently available CO_2 capture and compression processes are important in reducing the costs incurred for CO_2 capture.

Figure III-1 CCS Costs for Different Types and Configurations of Power Plants



III.A.5 Technical Challenges to CO_2 Capture for Coal-Based Power Generation

As discussed above, CO_2 removal technologies are not ready for widespread implementation on coal-based power plants, primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application (Kuuskraa, 2007). Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with process scale-up. For example, maintaining adequate

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the incremental cost per tonne of CO_2 captured and is calculated by dividing the difference in COE, \$/MWh, by the total CO_2 emissions captured, tonnes/MWh.

gas and/or liquid flow distribution in the larger absorption and regeneration reactors required for power plant applications could prove difficult.

Other technical challenges associated with the application of these CO_2 capture technologies to coal-based power plants include high capture and compression auxiliary power loads, capture process energy integration with existing power system, impacts of flue gas contaminants (NO_x, SO_x, PM) on CO_2 capture system, increased water consumption and cost effective O_2 supply for oxy-combustion systems (see Appendix A, Table A-3) (Kuuskraa, 2007). The following is a brief summary of two of the more significant technical challenges of applying these technologies.

III.A.5.1 CO_2 Capture Impacts on Water Use

CO_2 capture uses large quantities of water due to the cooling water requirements of capture and compression (Ciferno et al., 2010). As part of recent DOE/NETL studies, subcritical PC, supercritical PC, oxy-combustion, and IGCC configurations, both with and without capture, were evaluated for a variety of factors including water withdrawal (water removed from a surface or groundwater source) and consumption (water not returned to the source) (DOE, 2010a; DOE, 2010b). The evaluations indicated that there will be a significant increase in overall water use by the subcritical and supercritical PC plants (80 to 90 percent), with more modest increases for IGCC and oxy-combustion plants (35 to 60 percent), while maintaining a constant net power output (see Appendix A, Figure A-8).

III.A.5.2 CO_2 Capture Impacts on Existing Plant Retrofits

The EIA estimates that U.S. electricity demand will grow at the average annual rate of 0.9 percent through 2035 under current policy (EIA, 2010). Analyses of current and previous climate legislation have shown that electricity demand growth would be substantially less than in the business as usual case. This relatively low growth rate implies that the bulk of power sector emission reductions will need to come from the existing fleet, making the availability of cost-effective retrofits an important issue. Implementation of CCS to retrofit plants will be challenging because the size and space requirements for CO_2 capture process equipment are significantly greater than for conventional air pollution controls. Providing adequate space for CCS retrofits could prove difficult for certain plants. In addition, construction will have to be completed around the existing equipment at the plant. Another retrofit issue relates to the steam energy required for solvent regeneration. Diversion of power plant steam requires careful integration of the steam cycle and the CO_2 capture technology. Retrofits could also face challenges associated with proximity to a geologic sequestration site and/or a CO_2 pipeline.

III.B CO_2 Transport

III.B.1 Introduction

The transportation of CO_2 is a vital component of the CCS process. Even though CO_2 transportation will likely be less costly than CO_2 capture, developing a transportation infrastructure to accommodate future CCS projects may encounter challenges regarding technology, cost, regulation, policy, rights-of-way, and public acceptance. However, given that CO_2 pipelines exist today and the similarity of this infrastructure to others that have been developed, such as natural gas pipelines, none of these challenges is expected to be a major barrier to deployment. Additional supporting material appears in Appendix B.

Pipelines are expected by many to be the most economical and efficient method of transporting CO_2 for future commercial CCS facilities (IPCC, 2005; Parfomak and Folger, 2007). Although capital costs are higher for pipelines, once constructed, they reduce the uncertainty associated with logistics, fuel costs, and reliance on other infrastructure that could increase the cost of CO_2 transportation.

CO_2 pipelines require the same attention to design, monitoring for leaks, and protection against overpressure as natural gas pipelines. The operational experience and similarity between construction and operation of CO_2 and natural gas pipelines provides experience that can be used to estimate future CO_2 transportation costs (Cosham and Eiber, 2008).

III.B.2 Existing CO_2 Pipeline Infrastructure

The history of transporting CO_2 via pipelines in the United States spans over 35 years. The oldest long distance CO_2 pipeline in the United States is the 140-mile Canyon Reef Carriers Pipeline in Texas, which began service for EOR in regional oilfields in 1972. In contrast, pipelines for natural gas transmission originated almost exactly 100 years earlier in 1872, when the first pipelines were built in Titusville, Pennsylvania, the birthplace of the modern oil industry. Approximately 50 million tonnes per year of CO_2 are transported through approximately 3,600 miles of CO_2-dedicated pipelines in the United States (see Appendix B, Figure B.1) (Dooley et al., 2008). To put this in perspective, there are approximately 500,000 miles of hazardous liquid and natural gas pipelines, not including the 2.2 million miles of natural gas distribution lines, in the United States today (PHMSA, 2010).

III.B.3 CO_2 Design Construction, Operations and Safety

The design, construction, operation, and safety requirements for CO_2 pipelines have been developed over the past 30 years and are not considered barriers to the deployment of CCS technologies for the five to ten commercial projects planned by 2016 or commercial efforts after 2020. The standards for CO_2 pipelines are detailed in 49 C.F.R. § 194 and administrated by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration

(PHMSA) and various State agencies. Additional information on design, construction, operation, and safety requirements are discussed in Appendix B.

III.B.4 CO_2 Transport Cost

Cost estimates for constructing new CO_2 pipelines and for transporting CO_2 through these pipelines depend on a variety of factors such as the distance between the capture and storage points, the terrain the pipeline has to pass through, the anticipated flow rate of CO_2, and population and infrastructure development density. In certain circumstances, it may be more economical to transport CO_2 a longer distance to a lower cost high-quality storage formation than it is to transport it over a short distance to a more expensive storage operation in a lower quality storage field. Local costs for labor and materials will also affect overall CO_2 transportation costs. Recent studies have shown that CO_2 pipeline transport costs for a 100-kilometer (62 mile) pipeline transporting 5 million tonnes per year range from approximately $1 per tonne to $3 per tonne, depending on the factors discussed above (McCollum and Ogden, 2006; McCoy and Rubin, 2008).

Transporting CO_2 via pipelines presents opportunities for cost sharing if multiple capture facilities could use parts or all of the same pipeline system to become fully integrated with storage sites.

III.B.5 Anticipated Future CO_2 Pipeline Development

If CCS becomes commercially deployed, pipelines are expected to become the principal form of transport to bring CO_2 from point sources to geologic storage sinks such as saline formations, coal seams, and oil and gas fields (Dooley et al., 2008). A review of the 500 largest CO_2 point sources (primarily coal-fired power plants) in the United States shows that 95 percent are within 50 miles of a possible storage site (Dooley, 2006). However, until a geologic storage formation is fully characterized, the length of the pipeline needed cannot be assumed. In addition, incentives for CO_2 storage and EOR could influence how a pipeline network may evolve.

Modeling of the ACES Act of 2009 projects that by 2020 and 2030, approximately 180 and 480 million tonnes, respectively, would be captured, transported, and securely sequestered in deep geologic formations. These quantities of CO_2 represent between 4 and 10 times the amount of CO_2 transported in the United States in 2009, resulting in a need to construct new pipelines.

Separate studies completed by the Interstate Natural Gas Association of America (INGAA) and the Pacific Northwest National Laboratory (PNNL) looked at the amount of infrastructure necessary to support future CCS deployment (Dooley et al., 2008; The INGAA Foundation, 2009).[46] The estimated length of pipelines needed for commercial deployment of CCS ranged from 5,000 to 13,000 miles in 2020 and from 22,000 to 36,000 miles through 2030. Between 1998 and 2007 the natural gas industry built 20,829 miles of pipelines in the United States (EIA, 2008). While expected construction rates seem reasonable, CO_2 pipeline development will compete for resources, training needs, and additional draws on quantities of available commodities such as steel.

III.C CO_2 Storage

CO_2 storage refers to the process of injecting CO_2 into subsurface formations for long-term sequestration. CO_2 storage projects are multi-phase operations that include: (1) a pre-injection phase of site characterization that involves geologic evaluation of site suitability, modeling to predict the extent of the CO_2 plume and pressure front, and identification and plugging of artificial penetrations that could serve as conduits for fluid movement; (2) an operational phase during which CO_2 is injected and the injection well is tested, ground water geochemistry is monitored, and the CO_2 plume is tracked; and (3) a post-injection phase of site monitoring to verify that the project poses no risk to underground sources of drinking water (USDWs) and site closure.

This section of the report presents a brief overview of CO_2 storage in geologic reservoirs. CO_2 reuse is not addressed in this section, but is considered a potential alternative approach to mitigating CO_2 emissions and is discussed in Appendix D.

III.C.1 Introduction

Although engineered storage of CO_2 in geologic reservoirs is a relatively new concept, large-scale natural CO_2 formations are known in numerous reservoirs worldwide, and many natural gas formations contain CO_2. These natural examples demonstrate that large volumes of CO_2 can be retained in the subsurface stably over geologic time. Natural reservoirs can store as much as 5,600 million tonnes (100 trillion cubic feet) of CO_2 and can be as pure as 98 percent. They also provide natural laboratories to test the long-term interaction of CO_2 with subsurface fluids, reservoir mineralogy, and seals.

III.C.2 Status of Technology

III.C.2.1 CO_2 Enhanced Oil Recovery

Since the 1970s, engineered injection of CO_2 into geologic reservoirs has occurred in the context of EOR. CO_2-EOR and enhanced gas recovery technologies are used in oil and gas

[46] CCS deployment rates in the INGAA study are based on a summary of projections from a variety of legislative and other scenarios (page 57). CCS deployment rates in the PNNL study are based on WRE 450 and WRE 550 climate stabilization policies.

reservoirs to improve production efficiency. Injection of CO_2 is one of several enhanced recovery techniques that have successfully been used to boost production efficiency of oil and gas by re-pressurizing the reservoir, and in the case of oil, by also increasing mobility. Although some features of CO_2 storage may differ from EOR operations, these operations have developed many aspects of reservoir management and operation needed for the large-scale injection of CO_2. Use of such large volumes of CO_2 in EOR has shown that CO_2 can be injected at an industrial scale safely for long periods of time. Currently, approximately 50 million tonnes of CO_2 per year are injected, produced with the oil, captured, and re-injected. These operations are large in scale, with some injecting millions of tonnes of CO_2 per year, and some having already accumulated tens of millions of tonnes (Sweatman et al., 2009). As of year-end 2010, there were 114 CO_2-EOR projects within the United States producing 272,000 barrels of oil per day (Oil and Gas Journal, 2010).

Future deployment of CCS may fundamentally alter EOR in the United States. Many early geologic storage projects may be sited in, or below, depleted or active oil and gas reservoirs because the reservoirs have already been characterized for hydrocarbon recovery, may have suitable infrastructure (e.g., wells and pipelines) in place, and may provide revenues associated with recovery of additional crude oil. In addition, oil and gas fields now considered to be depleted may resume operation if there is an increase in availability and decrease in cost of anthropogenic CO_2. However, the extent that CO_2-EOR will be coupled with CCS remains uncertain (Dooley et al., 2010a).

In the context of CCS coupled with EOR, new reservoir management strategies may be needed: current strategies minimize CO_2 used per barrel of oil produced, whereas CCS strategies will likely seek to maximize CO_2 stored. These changes in use of the reservoir would result in pressure increases. EPA is developing tailored regulatory requirements and management strategies to safeguard public health and the environment in light of this effect (see section IV.B for details).

III.C.2.2 CO_2 Storage Potential

CO_2 storage potential is estimated to be large. Estimates based on DOE and International Energy Agency (IEA) studies indicate that areas of the United States with appropriate geology could theoretically provide storage potential for more than 3,000 billion tonnes of CO_2—large enough to store the amount of CO_2 emissions currently emitted from the entire coal fired electricity sector in the United States for over 1,000 years.[47]

As an outgrowth of efforts in the Regional Carbon Sequestration Partnership (RCSP) program, DOE produced the 2008 Carbon Sequestration Atlas of the United States and Canada, which

[47] The coal fired electricity sector emitted 1,945.9 million tonnes of CO_2 in 2008. (EIA, 2009)

evaluated geologic storage potential with respect to three categories of storage reservoirs. The Atlas reports that storage resource and capacity[48] in various types of formations in the United States and parts of Canada could be as high as:

- Oil/gas fields: approximately 140 billion tonnes;
- "Unmineable"[49] coal seams: approximately 160–180 billion tonnes; and
- Saline formations: approximately 3,300–12,600 billion tonnes.

Storage resource estimates are regionally variable, but details are being refined in ongoing efforts by both DOE and USGS. Estimates of the magnitude of storage resource contain uncertainties arising from a number of factors, including geologic factors (e.g., heterogeneity in reservoir porosity/permeability, caprock integrity, etc.) and hydrologic factors (e.g., movement of CO_2, brines, and pressure fronts). These storage resource estimates do not assess economic feasibility.

The Intergovernmental Panel on Climate Change (IPCC) concluded that there is need for "more development and agreement on assessment methodologies" for estimates of storage resource (IPCC, 2005). Research by DOE and USGS is addressing some of the factors contributing to uncertainties in estimates, for example:

- Improvements to the efficiency factors (the portion of pore space that the CO_2 can occupy) used in estimates of storage resource and capacity;
- Clarification of open vs. closed reservoirs and potential impact on estimates of storage resource capacity; and
- Expansion of site-specific details necessary for rigorous assessments.

Under authority provided to it in the Energy Independence and Security Act of 2007 (P.L. 111-140), the USGS has published a methodology for carrying out a national assessment for geologic sequestration (Brennan et al., 2010). USGS is using this methodology to begin an assessment of the United States' potential for geologic carbon sequestration in petroleum reservoirs and saline formations.

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[48] Storage capacity implies a very high level of confidence in the accuracy of the estimates of pore volume available for storage and ready for commercial development. This results from significant investment of funding into site characterization activities to prove the certainty of the injection zones to safely store the commercial quantities needed by the point source operator. Storage resources, however, do not have commercial status. Instead they can be categorized based on the amount of characterization that has been performed to reduce the uncertainty of the pore volume to be able to accept and permanently store commercial quantities of CO_2.

[49] An official definition of "unmineable" has yet to be determined and varies with technological advances and economics; the Atlas numbers assume 2008 technology and economics, as discussed in detail in Appendix C.

III.C.2.3 CO_2 Storage Security

The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, IPCC concluded that "it is considered likely[50] that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, hence, risk profiles (e.g., IPCC, 2005).

Commercial-scale experience is limited but encouraging; these efforts are working to demonstrate that application of the best available science and technology is central to ensuring storage integrity at each site. Experience at commercial-scale sites includes the following:

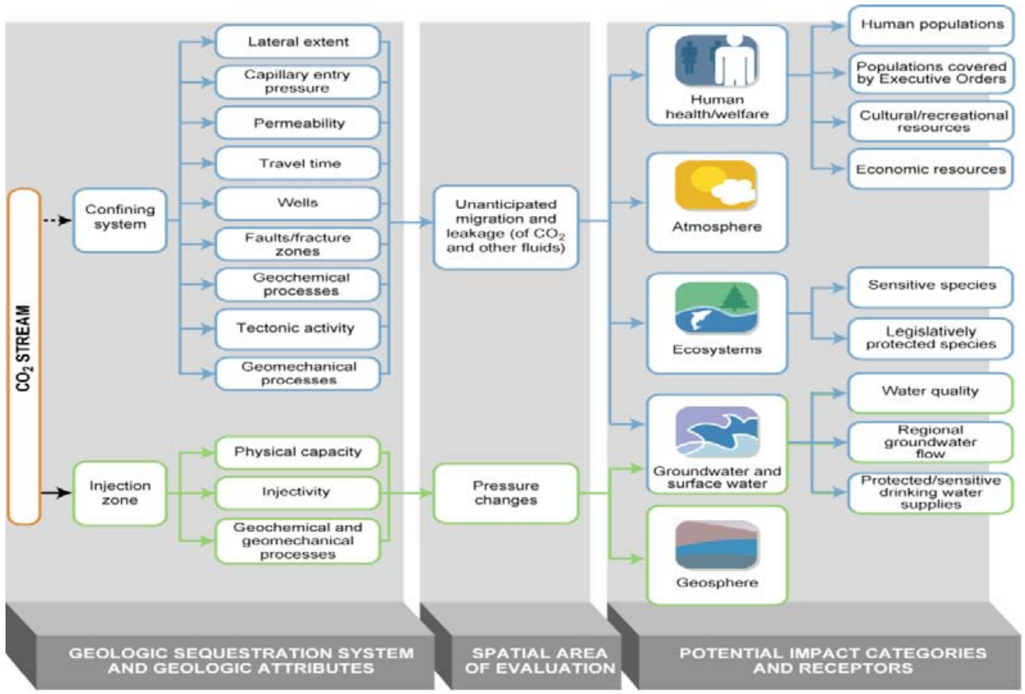
- Up to 14 years of continuous monitoring at large-scale CCS projects demonstrates geologic storage security (e.g., Sleipner, Snøhvit, Weyburn, In Salah); and
- Monitoring at large EOR sites provides additional data that suggests nearly 40 years of storage security (e.g., sites in the Permian basin of West Texas).

Additional commercial-scale experience is needed to confirm these estimates for a range of geological conditions.

EPA has also developed a Vulnerability Evaluation Framework (Figure III-2) to systematically identify those conditions that could increase the potential adverse impacts from geologic storage and that provides a basis for identifying key factors to minimize risk.

[50] The IPCC definition of "likely" is a probability between 66 and 90 percent.

Figure III-2 Vulnerability Evaluation Framework for Geologic Sequestration of CO_2



Source: EPA (2009a)

Broad consensus exists[51] regarding potential failure modes and impacts associated with CO_2 storage. Key potential impacts could result from slow sustained releases as well as from rapid releases. For example, if improperly managed, CO_2 storage may endanger USDWs. While CO_2 itself is not a drinking water contaminant, CO_2 in the presence of water forms a weak acid, known as carbonic acid, that, in some instances, could cause leaching and mobilization of naturally-occurring metals or other contaminants from geologic formations into ground water (e.g., arsenic, lead, and organic compounds). Additionally, pressures induced by injection may force native brines (naturally occurring salty water) into USDWs, causing degradation of water quality and affecting drinking water treatment processes.

CO_2 is not explosive or combustible. Rapid release of CO_2 could, however, damage an injection well during operation and provide a conduit for contamination of USDWs. If supercritical CO_2 is injected into shallow formations where pressures are not high enough to maintain its supercritical state and the CO_2 reverts to a gas, it could cause expansion of gaseous CO_2, a drop in temperature (the Joule-Thomson effect), and then freezing and thermal shock in the vicinity of the well. This thermal shock could compromise the integrity of the injection well, increasing potential for fluid movement and contamination of USDWs.

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[51] See, for example, the EPA Vulnerability Evaluation Framework in Figure III-2 or (Carbon Sequestration Leadership Forum, 2009).

In addition to risks to USDWs, injection activities could pose risks to the atmosphere, surface water, human health, ecosystems, and the physical environment. While CO_2 is not toxic, direct exposure to elevated levels of CO_2 can cause both chronic (e.g., increased breathing rate, vision and hearing impairment) and acute health effects to humans, animals, and vegetation, depending on the concentration and duration of exposure. The measures taken to prevent migration of CO_2 to USDWs would also minimize the risk of CO_2 migration to the surface.

It is expected that, should these impacts arise, they can be detected through appropriate monitoring, allowing consequences to be mitigated through readily available technology.

The risk of a rapid release of large and sustained amounts of CO_2 from the storage reservoir is believed to be low when appropriate natural and engineered factors are accounted for, including:

- During injection, pressures at the wellbore are monitored and maintained well below critical pressures for the reservoir to prevent over-pressurization.
- Injection pressures drop off rapidly away from the wellbore vicinity, lowering any potential for rapid release.
- Proposed SDWA Underground Injection Control (UIC) Class VI requirements for wellbores (see Section IV.B.1.2 for detail) specify cementing along the entirety of the wellbore, greatly reducing the chance of leaving an open space section for CO_2 flow along the wells.
- Natural mechanisms associated with the small pores in which CO_2 is stored further act to restrict rates and volumes of CO_2 released should a wellbore fail.

Best practices documents are being developed to promote storage security, including several documents as products from the RCSP program and a number of guidance documents from EPA that will accompany its new rule-making.

III.C.3 Demonstrations of CO_2 Storage Technologies

III.C.3.1 Regional CO_2 Sequestration Partnership Projects

In 2003, DOE initiated the Regional Carbon Sequestration Partnership (RCSP) program to provide guidance and experience related to developing the technology, infrastructure, and regulations needed to implement storage of CO_2 in the various regions and geologic formations found across the United States. The RCSP program has three phases: identification and characterization of potential sequestration opportunities (Phase I), small-scale testing (Phase II), and large-scale testing (Phase III). Phase I has been completed, and Phase II is nearly completed. Phase III was initiated in 2008 and includes nine large-scale projects, one of which has already begun injection operations. The more than 20 small-scale field tests that were conducted as part of Phase II have already yielded valuable information on how to safely and efficiently store and monitor CO_2 in common formations found in the United States.[52]

Additional studies are planned or underway. Based on data tracked by EPA and DOE, as of April 2010, a total of 56 active storage or integrated capture and storage projects are in various phases: 13 percent are undergoing site selection/characterization, 33 percent in the preliminary design/ infrastructure development phase, 24 percent are in the process of obtaining permits, 4 percent are drilling wells, and 26 percent are injecting. (See Appendix C.1.3 for more detail.)

III.C.3.2 International Geologic Storage Projects

Engineered storage of CO_2 is occurring at several large-scale operations: Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada. Although limited in number, these projects demonstrate CO_2 storage at commercial scale over a variety of geologic conditions and monitoring approaches that will be applicable to many potential CO_2 storage sites worldwide. (See Appendix C for details).

III.C.4 CO_2 Storage Cost

Costs associated with CO_2 storage have been estimated to be approximately $0.4–20/tonne.[53] For example, the IPCC summarized several studies from 2002–2005 reporting estimates in the range $0.4–12.2/tonne CO_2 stored plus $0.16–0.30/tonne CO_2 stored (undiscounted) for monitoring (IPCC, 2005). Estimates vary depending on numerous factors, including type of reservoir, existing information/infrastructure for the site, onshore versus offshore storage, extent of monitoring, regional factors, etc. Costs may vary regionally and could affect "dispatching" of geologic storage options, which, in turn, would affect strategies for development of any pipeline networks. Costs may vary over time as earlier operations exploit more certain and lower-cost storage sites. Recent estimates of storage costs derived from current commercial-scale projects are $11–17 per tonne (Sleipner); $20 per tonne (Weyburn) and $6 per tonne (In Salah).

Additional revenues from oil production may offset some costs for CO_2 storage in the context of an EOR operation. CO_2-EOR provides two potential economic incentives for encouraging the deployment of CCS, 1) CO_2 sales revenues at the individual project level, and 2) an increase in the total amount of domestic crude oil production. At the present time, an important limiting factor in new CO_2-EOR projects is a shortage of CO_2.

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[52] Additional information about the partnership projects is available at http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html.

[53] Cost estimates are limited to capital and operational costs, and do not include potential costs associated with long-term liability.

The willingness of oil producers to pay for CO_2 supplies has the potential to defray a portion of the cost of building carbon capture and transportation facilities, particularly for those projects built first, as it is understood that the total EOR requirements are likely to be significantly less than most scenarios for the deployment of CCS. For example, several CCS projects listed in Table V-2 plan to sell their captured CO_2 for EOR. Along with Federal funding, the CO_2 sales are an important part of the project funding.

The second potential benefit of EOR for deployment of CCS is associated with increasing total domestic crude oil production which, in turn, reduces crude oil and product import dependency and the associated net expenditures on imports. For example, in EIA's AEO2010 reference case crude oil production from CO_2-EOR in 2035 is projected to be 1.3 million barrels per day. EIA found in its analysis of the American Power Act of 2010 that the additional CCS deployment spurred by the legislation would result in 0.8 to 1.0 million barrels per day of additional crude oil production (EIA, 2010). The resulting reduction in U.S. net import expenditures from the incremental domestic crude oil production would range from $36 billion to $45 billion per year using a case crude oil price of $124 per barrel.

Additional information is needed from ongoing CCS projects, as well as information related to costs associated with regulatory compliance (including monitoring costs and long-term stewardship costs) (e.g., IPCC, 2005).

III.C.5 Technical and Other Considerations for CO_2 Storage

III.C.5.1 Geologic Siting and Area of Review Monitoring

Site characterization is a fundamental component of selecting safe locations for geologic storage. The proposed new Class VI regulation under the SDWA UIC program requires owners or operators of CO_2 storage wells to perform detailed assessments of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed CO_2 storage site. These assessments are intended to ensure that sequestration wells are sited in appropriate locations and inject into suitable formations that can receive and confine injected fluids to ensure protection of USDWs from endangerment in the onshore environment and the sub-seabed within State territorial waters. Data collected during site characterization also inform the development of construction and operating plans, provide inputs for area-of-review (AoR) delineation models (see below), and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

Under the UIC Class VI proposed rule, operators of geologic storage projects must also model the AoR, which includes the region surrounding the geologic storage project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream; it is based on available data collected during the site characterization process.

Operators must also periodically reevaluate the AoR over the life of the project to incorporate CO_2 monitoring and operational data into models in order to ensure that the CO_2 plume is moving within the subsurface as predicted.

III.C.5.2 Monitoring, Verification, and Accounting

Monitoring, verification, and accounting (MVA) are important components of managing a geologic storage project and ensuring that the CO_2 plume and associated pressure front are moving through the subsurface as predicted. In the proposed new Class VI regulation under the SDWA UIC program, during injection operations, operators must develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure fall-off testing; mechanical integrity testing of the well; ground water quality monitoring; and CO_2 plume and pressure front tracking. A rigorous monitoring regime will provide information about site performance when compared against baseline information, previous monitoring results, and simulation models of site operations.

Wide-scale deployment will need validated quantifiable protocols for each stage of a CCS project. Variation in local surface and subsurface characteristics necessitate that these monitoring strategies are site-specific, but general approaches (including the establishment of standards) are needed, particularly in the context of wide-scale deployment of CCS. In addition, the development of risk-based monitoring protocols may also be appropriate to verify predictions of the site performance and/or to integrate with risk-minimization strategies.

Additional information on MVA technologies can be found in the EPA General Technical Support Document to the proposed GHG reporting rule for CO_2 sequestration facilities (EPA, 2009b), IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006), API/IPIECA Guidelines for CCS (IPIECA, 2007), Department of Energy MVA Best Practices Manual (NETL, 2009a), and the International Energy Agency GHG R&D Programme monitoring tool Web site (IEA, 2009b). In addition, Dooley et al. have summarized MVA technologies being deployed at current CCS projects (Dooley et al., 2009).

Continued development is needed for MVA tools to improve aspects related to quantification and resolution of CO_2 in the subsurface, detection of fractures and other potential leakage paths, intermittent leakage, etc. (IPCC, 2005).

III.C.5.3 Post Injection Site Care

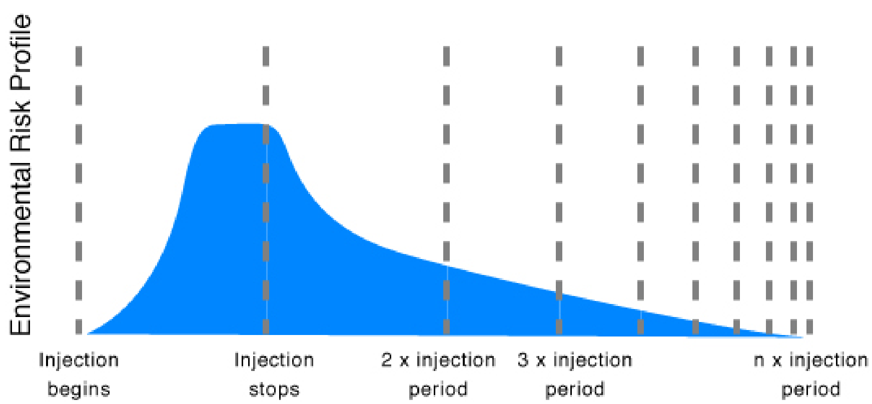
The proposed new UIC Class VI regulation under the UIC program (see Section IV.B.1.2 for details) includes detailed requirements for monitoring following cessation of injection; under this proposed regulation, operators of geologic sequestration wells will be required to perform comprehensive and extended post-injection monitoring and site care to verify that the CO_2 plume is moving as predicted. This monitoring continues until it can be demonstrated that movement of the CO_2 plume and pressure front have stabilized and the injectate does not pose a risk to USDWs.

III.C.5.4 Long-Term Stewardship

Geologic storage security is expected to increase over time through post-closure, resulting in a decrease in potential risks. This expectation is based in part on a technical understanding of the variety of trapping mechanisms that work to reduce CO_2 mobility over time (e.g., IPCC, 2005). In addition, site characterization, site operations, and monitoring strategies can work in combination to promote storage security.[54] As a result, risk profiles are expected to decline over time (Figure III-3).

Figure III-3 Qualitative Profile of Environmental Risk Over Time for a CO_2 Storage Operation.

Risk is expected to increase during the injection phase of a storage project but decline over time as the system equilibrates and multiple trapping mechanisms engage.



Source: Adapted from Benson (2007)

Risk factors depend on site-specific characteristics, so they must be assessed for each potential geologic storage site. However, experience from large demonstrations, oil/gas industry, etc. has provided insight into a number of key considerations for minimizing risks, including ensuring wellbore integrity, ensuring seal integrity, and maintaining appropriate injection pressures.

Long-term stewardship will require a quantitative, probabilistic methodology to calculate risk profiles at geologic storage sites. Large-scale tests and commercial projects are developing field experience to confirm methodologies and tools that form the technical basis for long-term predictions; natural analog sites are available for observations to confirm long-term predictions.

[54] DOE is developing best practices documents on these factors based on experience from the Regional Carbon Sequestration Partnership program.

DOE's National Risk Assessment Partnership (NRAP) initiative is building the scientific basis for quantifying risk profiles. NRAP comprises a broad interdisciplinary team of scientists and engineers drawn from across the DOE complex developing and confirming (through targeted laboratory and field observations/experiments) a suite of science-based tools for calculating the residual risk associated with specific geologic storage sites.

III.C.5.5 Potential Impact of Impurities in the CO_2 Stream

Purity of the injected CO_2 stream is a consideration for storage because co-captured impurities could affect the storage processes in a number of ways, including by changes in pH and oxidation state that might affect dissolution and precipitation reactions as well as mobility of metals present in the reservoir rocks. These factors can be incorporated into evaluations of a proposed storage operation. Details on the potential impacts of impurities are discussed in Appendix C.3.2.

III.C.5.6 Multiple Injections in a Single Basin

Scale-up from a limited number of demonstration projects to widescale commercial deployment increases the likelihood of multiple injections within the same storage basin. This may necessitate consideration of basin-scale interactions and impacts. For example, brine displacement and/or pressure buildup could have impacts both locally (e.g., integrity of the caprock) and basin-wide (e.g., overlap of pressure fronts, which could limit effective storage capacity). Pressure management schemes, such as brine extraction from deep storage reservoirs, may be options to mitigate some of the basin-scale factors associated with wide-scale deployment.

III.C.5.7 Property Rights

Deployment of CO_2 sequestration would necessitate addressing several land use and property rights issues, including obtaining permission from the surface owner for the injection well(s) and related surface facilities; securing rights-of-way (e.g., for pipelines); placement and access to monitoring wells and devices at various locations; subsurface movement of injectate; and elevated regional pressure fronts due to injection. New Federal requirements proposed under the UIC Program for CO_2 storage wells include a provision that owners or operators of a geologic sequestration well submit a corrective action plan as part of their permit application. The plan should identify how site access would be guaranteed for areas requiring future corrective action. Access may also be needed for other aspects of the CO_2 storage operation, such as groundwater monitoring outside of the injection zone. Stakeholders noted aggregation of subsurface pore space within target injection formations as particularly critical to the success of CO_2 storage projects in the near- and long-term.

Pore Space Ownership

CO_2 sequestration project developers would have to identify the owners of property rights or interests in the pore space of a target injection formation and confining layer. Injectors would need to obtain the rights to ownership or use of pore space in which they are storing CO_2.

Pore space ownership issues will vary from State to State. In States where there is no prior mineral severance, the owner of the surface estate is deemed to be the owner of the subsurface pore space. This would make the owner of the surface estate the entity from which the project developer would need to obtain ownership, a lease, or access to, the pore space. Where subsurface minerals exist, many surface owners may have severed ownership of the subsurface mineral rights and conveyed them to third parties. In these arrangements, generally the subsurface owner has the legal right to reasonable use of the surface estate for production of the minerals. A potential conflict may result when there are competing uses of the surface estate for the purposes of CO_2 storage and mineral production.

Aggregation of Pore Space

Pore space could be acquired through an agreement with a single owner who owns all surface and subsurface rights. However, issues may arise where pore space needs for CO_2 storage extend over an area where numerous owners hold rights. Currently in most States, owner-operators would need to engage in private commercial transactions with property owners to acquire ownership or lease the pore space. While this is a feasible approach where relatively few owners have rights to large areas of pore space and are willing to sell or lease, the use of private commercial transactions can become more challenging where owner-operators would need to engage in individual negotiations with an extremely large number of property owners. Several options for reducing uncertainty about the ownership of pore space in the United States, including both on the State and Federal levels, have been proposed by stakeholders, addressing the scale of subsurface pore space required for CO_2 storage. These options are diverse; some would rely on private transactions, some on action by State government, and some on Federal intervention. These options are discussed in Appendix L. Which option or options are appropriate will depend on, among other factors, the success of private commercial transactions in resolving pore space issues and the extent and nature of State legislation in this area. In addition, several States have taken action to clarify or to codify the rules relating to CO_2 storage property-rights issues such as ownership, access to pore space, interaction between mineral estate interests and CO_2 injection operations.[55]

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[55] Selected State legislation relating to CO_2 sequestration property rights as of April 2010 includes Louisiana (La. Rev. Stat. Ann. § 30:2104(E) (2010)), Montana (Lont. Code Ann. § 82-11-180 (2010)), North Dakota (N.D. Cent. Code §§ 38-20-10, 47-31 (2010), Oklahoma (Okla. Stat. 27A § 3-5-105(A) (2010)), Texas (Texas Nat. Res. Code Ann. § 120.002 (2010)), and Wyoming (Wyo. Stat. Ann. §§ 34-1-152, 34-1-202, 35-11-316 (2010)).

III.D Conclusions

III.D.1 CO_2 Capture

- Carbon dioxide gas separation technologies have been developed and employed in the industrial sector (e.g. petroleum refining, natural gas purification) for more than 70 years.
- Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.
- Cost estimates for employing current technologies on new and existing fossil energy power plants in terms of cost per tonne of CO_2 avoided, range from $60/tonne for IGCC, $95/tonne for PC to $114/tonne for NGCC.[56]
- Existing CO_2 separation technologies deployed on new and existing fossil energy power plants will result in a significant energy penalty, up to 30 percent.
- Ten large-scale power plant and industrial plant demonstrations projects are currently being pursued by DOE and will provide information and experience regarding operations at scale.

III.D.2 CO_2 Transport

- Technologies for the transport of supercritical CO_2 through pipelines exist today.
- Approximately 3,600 miles of CO_2-dedicated pipelines exist in the United States, carrying approximately 50 million tonnes to enhanced oil recovery projects.
- It is anticipated that comprehensive climate change legislation could incentivize the deployment of the technology and require industry to expand the existing network of CO_2 pipelines.
- No technology barriers have been identified that would hinder the development of these additional pipelines in the United States.

[56] The dollar per tonne of CO_2 avoided is the incremental cost of CO_2 emissions avoided by applying CCS and is compared to a similar non-captured facility. It is calculated by dividing the difference in COE, $/MWh, by the difference in CO_2 emissions with and without CO_2 capture, tonnes/MWh. The dollar per tonne CO_2 captured is the incremental cost per tonne of CO_2 captured and is calculated by dividing the difference in COE, $/MWh, by the total CO_2 emissions captured, tonnes/MWh.

- Challenges may exist with respect to resource constraints that the industry and market place will need to address over time.

III.D.3 CO_2 Storage

- Large-scale CO_2 injection for sequestration purposes is already occurring at several sites, providing a foundation for commercial-scale demonstrations.
- Ongoing regional-scale assessments suggest a large resource potential for storage in the United States. Detailed site assessments (e.g., ongoing DOE and USGS efforts) aim to demonstrate site capacities that can lead to refined national capacity estimates.
- To enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes, with large-scale projects targeted at high-priority reservoir classes and smaller-scale projects covering a wider range of classes that are important regionally.
- Storage security is believed to increase over time. Field-validated methodologies will help to quantify potential for risks tied to long-term liability.
- Scale-up from a limited number of demonstration projects to widescale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.).

IV. Current Barriers and Concerns for CCS Deployment and Commercialization

There are four major concerns for near- and long-term deployment of CCS technologies:

- The existence of ***market failures***, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a ***legal/regulatory framework*** for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely.
- Clarity with respect to the ***long-term liability for CO_2 sequestration***, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- Integration of ***public information, education, and outreach*** throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

In addition, some stakeholders have voiced concerns about training/workforce capacity and physical/infrastructure capacity. The widespread cost-effective deployment of CCS will require hiring, training, and retaining a large workforce of highly skilled professionals in the private sector to design, build, and operate facilities. Similar workforce challenges will face the public sector in meeting the need for permitting and regulating CCS activities.

The Task Force recognizes that aggregation of pore space can be a barrier to deployment of CO_2 sequestration projects, as noted earlier, and that several States are taking actions to address this issue.[57] Several options to address aggregation of pore space are presented in Appendix L.

Siting considerations for CO_2 pipelines may evolve with time as a function of CCS deployment rate and geographic distribution. This report reviews varying models of oversight between Federal, State and local entities. (See Appendix M for more details.)

This section outlines current barriers and concerns for CCS deployment for the four major issues identified above. Options for addressing each issue and their advantages and disadvantages are presented in Sections V, VI, VII, and VIII.

[57] See Section III.C.5.7.

IV.A Market Failures

IV.A.1 Overview

The role for government in the deployment and commercialization of CCS is based on the premise that it is subject to market failures (instances where the free market does not yield an optimal outcome). Economists generally propose that government intervention in the economy is justified when there is both an identifiable market failure and a feasible means for overcoming or compensating for the market failure in such a way that the net benefits are likely to be positive. The costs of intervention involve the potential for introducing inefficiencies, such as distortions to capital and labor markets that result from policies that are poorly targeted in scope or size, and from distortionary taxes used to raise revenue to pay for the intervention. The opportunity cost of lost spending on other government priorities is another important consideration.

The market failures that prevent investors from capturing the full social benefit of investments in technologies that mitigate GHG emissions result in less than optimal levels of investment in these technologies, and may impede cost-effective deployment. CCS is not unique in this regard – it is one of many technologies affected by this market failure. Cost, in and of itself, is not a barrier, because markets use cost information as a guide for investment behavior to deliver least-cost solutions. However, the two market failures described below impede early CCS deployment that could provide learning and lower future costs. Therefore, a complementary portfolio of measures to target these market failures will introduce incentives for the cost-effective deployment of CCS.

IV.A.2 Failure to Account for Social Cost of Greenhouse Gas Emissions

The foremost economic barrier to developing and deploying low-carbon technology is the market's failure to price the negative externality of GHG emissions that drive anthropogenic climate change, in other words, a price on carbon. Establishing a clear price signal on GHG emissions that rises over time will incentivize businesses to look for ever-cheaper ways to reduce emissions. It will also put established low-carbon technologies on a level playing field with conventional carbon-emitting technologies, yield near-term opportunities for emerging technologies, and create greater market certainty for long-term investments in new or improved low-carbon energy technology development.

Internalizing the cost of GHG emissions is a threshold barrier for further CCS technological development. Without an economic consequence for emitting GHGs, there is no economic rationale for capturing and storing emissions. However, a GHG price signal does not address the other major market failure affecting CCS development, as described below, which requires a separate policy remedy.

IV.A.3 Knowledge Spillovers from Research and Development of CCS Technology

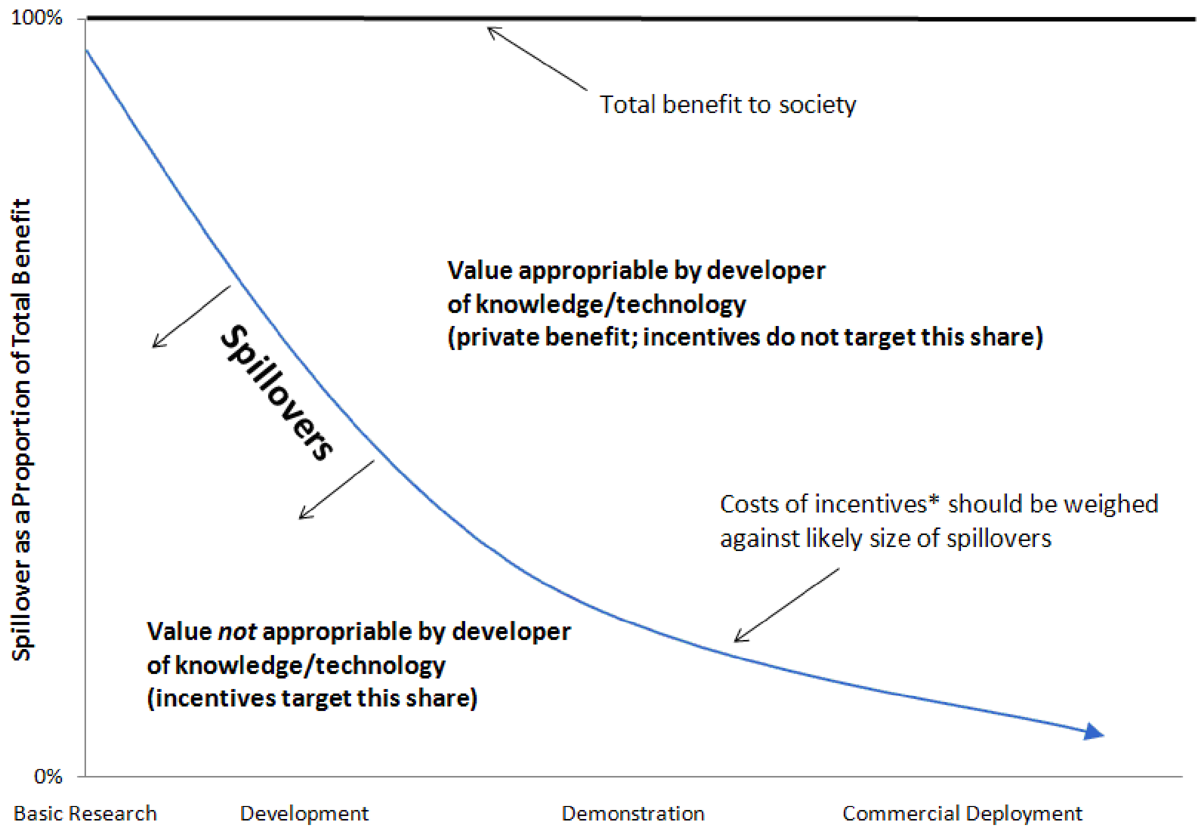
Even with clear market signals that internalize the full cost of GHG emissions, technological progress can be delayed by another market failure: the inability of private-sector innovators to incorporate the full benefits from the knowledge they create in researching, developing, and deploying new technologies. This phenomenon, known as "knowledge spillovers," leads private sector actors to under-invest in RD&D. Private sector actors will tend to invest only to the extent that their RD&D costs are less than the appropriable, private benefits, even though such investment may provide additional social benefits. Put simply, individual firms will not typically take on investments for the good of the broader industry or society as a whole unless there is a clear return on that investment to the firm. Therefore, the private market has a limited incentive to invest in "shared learning" that would lead to an improved economic outcome for society as a whole. This market failure is most pronounced for research in the basic sciences, which can yield highly valuable but difficult to appropriate economic returns.

Investments that create knowledge further down the chain of technology development and deployment can also create spillovers. For instance, the experience of designing, fabricating, and operating the initial CCS installations (including separating, transporting, and storing CO_2) creates knowledge (often referred to as learning-by-doing), and some portion of the gains from that knowledge cannot be captured by the firm making the investments.

As a technology moves through the life cycle from basic research to more targeted development and ultimately deployment, the share of the knowledge generated—and therefore the benefits of that knowledge—that is not appropriable by the investor tends to get smaller. This is largely because a larger share of the total social benefit created by innovations in the technology can be captured by those making the investments through patents or other means. The smaller spillovers that occur as technologies mature, along with the fact that we do not know *ex ante* which particular technologies will be the most cost-effective, suggest that care must be taken in targeting incentives so as not to create distortions that outweigh the gains to society of promoting a particular technology.

Figure IV-1 shows a stylistic representation of the relationship between spillovers as a share of the total benefit to society of new knowledge and the phase of knowledge/technology development. Section V of this report describes how policy makers can address the market failure of knowledge spillovers, including the advantages and disadvantages of applying a variety of incentive structures for the public share of investment in CCS technology.

Figure IV-1 Private versus Spillover Benefits of Knowledge Creation



* Costs of incentives include budget costs, opportunity costs of budget resources, and the costs of distortions from taxes and imperfectly targeted subsidies

IV.B Regulatory Framework Governing the Capture, Transportation, and Storage of CO_2

Regulatory uncertainty is widely identified as a key barrier to CCS deployment in the United States. Existing environmental statutes and programs such as the SDWA UIC Program apply to geologic sequestration of CO_2. However, because CCS has not been widely deployed, there is uncertainty about how environmental statutes will apply, whether there are gaps or overlaps, and if the current framework is adequate for both near- and long-term deployment of CCS. This section describes how key provisions of current environmental, natural resources, and other laws may govern the capture, transportation, and sequestration phases of CCS.[58,59] This

[58] The full array of Federal, State, and local laws, as applicable, will govern any particular CCS project. Appendix F and Appendix G analyze in greater detail how selected environmental, natural resource, and other laws may apply to CCS. Acquisition of property rights needed to inject and store CCS and short- and long-term liability potentially

section also identifies some near- and longer-term challenges with implementing the existing regulatory framework.

IV.B.1 Current Framework

The current regulatory framework supports CCS projects moving forward now. The discussion below highlights two types of "cross-cutting" laws that may apply to all phases of CCS; examines those laws most relevant to each phase of CCS as deployed on private, onshore lands; and explains the regulatory framework uniquely applicable to deployment of CCS on Federal lands. Section VI provides more information on aspects of the current regulatory framework for CCS.

IV.B.1.1 Selected Cross-Cutting Laws

National Environmental Policy Act (NEPA)

CCS activities may trigger various Federal and State environmental planning review obligations. Of these, the Federal statute likely to be applicable to most phases of CCS projects is the National Environmental Policy Act (NEPA), 42 United States Code (U.S.C.) §§ 4321 to 4370f.[60] NEPA establishes national policy and goals to improve Federal planning by considering and minimizing impacts to the environment, and requires all Federal executive branch agencies to undertake specified assessments before they make final decisions about Federal actions that could have environmental effects. The environmental review process under NEPA also provides multiple opportunities for the public, States, Tribes, and local governments, among others, to participate in the Federal agency decision-making process, which will be critical to the success of CCS. Compliance with NEPA provides the opportunity for Federal agencies to cooperate throughout the NEPA process to ensure that the analysis addresses all relevant issues and to use a single document as the basis for final permitting decisions.

NEPA applies to a broad range of actions subject to Federal control or responsibility. Use of Federal or Tribal lands for the purposes of CO_2 pipeline siting or sequestration will require NEPA analysis. Non-Federal projects, which are not normally subject to NEPA, may become Federal actions where they are financed, assisted, or approved in whole or in part by the Federal government; however, this is a very complex area of the law and requires a fact-

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accruing from CCS are addressed in section III.C.5.7 and IV.C, respectively; the role of public lands in deployment of CCS is covered in section IV.B.1.3.

[60] Other cross-cutting Federal statutes may be relevant to a CCS project in some instances. For example, where Federal or private actions in CCS deployment might affect endangered or threatened species and their habitats in specified ways, the Endangered Species Act, 16 U.S.C. §§ 1531 to 1599, is applicable. Similarly, the NHPA, 16 U.S.C. §§ 470-470a-2, like NEPA, requires Federal agencies to evaluate impact of Federal actions on sites listed on, or eligible for, the National Register of Historic Places. See Appendix G for further discussion of these statutes.

intensive analysis to determine when a private project has become federalized. Because Federal agencies will likely be significantly involved, at least in the short-term, in the planning, financing, and permitting of CO_2 sequestration projects on private and Federal lands (on and offshore), NEPA could apply to those activities. Some permitting activities may be exempt from NEPA, however, where a statute or regulation provides for a similar environmental review process and public participation. For example, the issuance of a SDWA UIC permit for CO_2 injection by EPA would not require preparation of a NEPA analysis because the UIC permit process is considered to be the "functional equivalent" to the NEPA process.

NEPA requires the development of an Environmental Impact Statement (EIS), a more detailed evaluation of an action and alternatives to it, when a Federal agency determines that the environmental consequences of an action may be significant. Review under NEPA may be streamlined in some contexts, such as when Federal land will be used for CCS activities, through development of Programmatic Environmental Impact Statements (PEISs).[61] A PEIS could analyze the environmental impacts at a region-wide scale for either a pipeline corridor or network, or for regional CO_2 sequestration. Site-specific analysis under NEPA would still be required for specific pipeline or sequestration siting, but these site-specific EISs may be streamlined by being able to "tier" off the PEIS.

Conducting a programmatic NEPA analysis is rigorous, and that analysis should commence very early in the planning process for CCS. In fact, the law directs agencies to integrate the NEPA process into early planning efforts in order that appropriate NEPA analysis is performed and to reduce delay.[62] A PEIS can take two or more years to prepare and will involve public comment and substantial interagency coordination and analysis. Once site-specific projects are identified, NEPA analysis for such projects will require additional time, on the scale of two or more years, depending on the complexity of the project and the significance of the impacts. If this analysis is conducted early, it may provide an opportunity to further clarify many of the issues discussed in this report. On the other hand, attempting to conduct such an analysis late in the planning process would undercut the utility of the NEPA process and could cause delays in the implementation of CCS.

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[61] NEPA review may potentially be streamlined by the use of a "categorical exclusion." A categorical exclusion can apply when an agency has determined that certain actions "do not individually or cumulatively have a significant effect." 40 C.F.R. § 1508.4. A categorical exclusion, however, does not exempt a project completely from environmental review; an agency still must review for "extraordinary circumstances" that could remove a project from the categorical exclusion if a normally excluded action may have significant environmental effects. Id. At this stage, because of the novelty of many CCS activities, an agency is not likely to have an existing categorical exclusion that could be used, and would need to establish in conjunction with the Council on Environmental Quality that the applicable regulatory criteria for a new categorical exclusion are met.

[62] 40 C.F.R. § 1501.1(a).

Resource Conservation and Recovery Act (RCRA)

The Solid Waste Disposal Act, 42 U.S.C. § 6901 *et seq*, as amended (commonly referred to as RCRA), regulates "solid wastes," with Subtitle C of the Act addressing management of solid wastes that are also "hazardous wastes." RCRA Subtitle C establishes a comprehensive "cradle to grave" regulatory scheme, including requirements for generators and transporters, along with permitting and other requirements for hazardous waste "treatment, storage, or disposal" facilities.[63]

Under EPA's regulations, a solid waste is a hazardous waste if, among other things, it exhibits the characteristic of toxicity.[64,65,66,67] CO_2 captured from sectors amenable to CCS, such as electric generating facilities, could contain toxic chemical constituents such as arsenic, mercury, and selenium (IPCC, 2005; Apps, 2006). Whether a particular CO_2 stream is a hazardous waste based on toxicity will depend on whether it contains specific chemical constituents at levels above the toxicity characteristic concentrations in Table 1 of 40 C.F.R. § 261.24(b). A captured CO_2 stream that meets the definition of a hazardous waste will have to comply with all applicable RCRA requirements.

Various groups and studies have characterized potential RCRA applicability as a possible barrier to CCS deployment due to its complex regulatory regime.[68] Characterization of a CO_2 stream as "hazardous waste" would make the RCRA waste management scheme applicable to the generation, transportation, treatment, sequestration, and/or disposal of the CO_2 stream. This determination would mean that underground injection and sequestration of such a CO_2 stream would need to meet the requirements for Class I hazardous waste wells under the SDWA UIC

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[63] RCRA §§ 3001-05; 40 C.F.R. Parts 260-279.

[64] A solid waste is a hazardous waste if it is a listed hazardous waste, or if it exhibits any of four characteristics (ignitability, corrosivity, reactivity, or toxicity). 40 C.F.R. §§ 261.30-.33 and 261.20-.24.

[65] 40 C.F.R. § 261.24.

[66]Hazardous secondary material which is used or re-used as a substitute for a commercial product or as an ingredient in an industrial process to make a product may be excluded from the definition of solid waste under RCRA regulations. EPA's regulatory exclusion may apply to CO_2 that has been geologically sequestered if it is being stored for re-use in a product or ingredient. See 40 C.F.R. §§ 261.1(c)(5) and 261.2(e). To qualify for this exclusion, however, the hazardous secondary material must be legitimately recycled. In addition the hazardous secondary material cannot be accumulated speculatively, meaning, generally, that 75 percent of the accumulated secondary material must be used within a calendar year. 40 C.F.R. § 261.1(c)(8). Further, the EPA regulations state that this hazardous secondary material may not be burned for energy recovery nor re-used in a manner that constitutes disposal (i.e., being put on the land or used to make a product that is put on the land). See 40 C.F.R. § 261.2(c). See Appendix D for a discussion of potential end uses of CO_2.

[67] 40 C.F.R. § 261.2(a)(1)-(2), (b)(1).

[68] See, e.g., (GAO, 2008).

Program, §§ 1421 et seq., 42 U.S.C. §§ 300h et seq.,[69] rather than for the Class VI geologic sequestration wells proposed to be established under Federal Requirements Under the UIC Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells, 73 Fed. Reg. 43492, 43503 (July 25, 2008).

EPA is evaluating how and whether RCRA hazardous waste requirements may apply to certain CO_2 injectate. EPA is planning a proposed rule under RCRA to explore a number of options, including a conditional exemption from the RCRA requirements for hazardous CO_2 streams in order to facilitate implementation of geologic sequestration while protecting human health and the environment. EPA has created "conditional exemptions" in the past defining secondary materials as hazardous waste only if they are not managed pursuant to specified conditions (see, e.g., Military Toxics Project v. EPA, 146 F.3d 948 (D.C. Cir. 1998)).

IV.B.1.2 Selected Laws Applicable to Phases of Deployment of CCS on Private Onshore Lands

Capture of CO_2

One Clean Air Act (CAA) requirement that specifically applies to CO_2 capture is Subpart PP of the GHG Reporting Program. Facilities that capture CO_2 will be required to regularly monitor and report their emissions, as specified under 40 C.F.R. Part 98, Subpart PP. Subpart PP requires the reporting of CO_2 supplied to the economy and applies to all facilities with CO_2 production wells, facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream to sequester or otherwise inject it underground, and to importers and exporters of bulk CO_2.

Other relevant Clean Air Act provisions may apply to the capture of CO_2. For example, the New Source Review Program requires an existing major stationary source that undergoes a "major modification" that results in a "significant increase in emissions" to install state-of-the-art pollution control equipment.[70] As discussed in Section III.A energy is needed to capture and compress CO_2. This energy could be derived from diverting some of the energy produced by the facility, or by using energy from offsite. If a plant increases its production of energy to compensate for that loss, and if that results in a significant increase in emissions of other regulated air pollutants, the plant could be required to upgrade the balance of its air pollution control equipment.

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[69] Treating a geologic sequestration project as a Class I hazardous UIC well may result in a longer permit process than anticipated for the proposed Class VI geologic sequestration UIC well due to the additional requirement to obtain a RCRA permit. Additionally, the proposed Class VI geologic sequestration UIC well is specifically tailored to address CO_2's unique characteristics, unlike Class I hazardous UIC well requirements.

[70] CAA §§ 165 and 173, 42 U.S.C. §§ 7475 and 7503; 40 C.F.R. §§ 52.21(j)(3), 51.166(j)(3), and 51.165(b)(1).

Transportation of CO_2

Captured CO_2 may be transported by pipeline, truck, rail, barge, or supertanker. As discussed above in Section III.B, pipelines are considered to be the most economical and thus the most likely future method of transportation of CO_2. A mix of State and Federal laws applies to pipeline siting, construction, and operation.[71] Siting and construction of the approximately 3,600 miles of existing onshore CO_2 pipelines in the United States have generally been the province of State and local government.[72] State law also governs the rates, terms, and conditions of service provided by CO_2 pipelines.

The U.S. Department of Transportation (DOT), through the Office of Pipeline Safety in the PHMSA, has oversight responsibility for the safety of liquid CO_2 pipelines pursuant to the Hazardous Liquid Pipeline Act of 1979, as amended, 49 U.S.C. § 60101 *et seq*., and the Hazardous Materials Transportation Act, 40 U.S.C. 5101 *et seq*. Design, construction, operational, and emergency response requirements for CO_2 pipelines are contained in 49 C.F.R. Parts 190–199 and 40 C.F.R. Parts 171–180.

Storage of CO_2

Due to their importance and public interest, this section highlights the applicability of the SDWA UIC, CAA, and Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, commonly known as Superfund) programs to CO_2 sequestration. RCRA is discussed in Section IV.B.1.1.

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[71] In addition to the Federal laws discussed below, siting, construction, and operation of pipelines with significant Federal involvement may trigger NEPA review or ESA and NHPA requirements in some instances, as explained above. Operation of pipelines containing hazardous waste must also comply with RCRA, as discussed earlier, and may have various other obligations under environmental statutes such as the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), EPCRA and the CAA, where applicable by their terms.

[72] In 1979, the Federal Energy Regulatory Commission (FERC) ruled that because CO_2 pipelines do not transport natural gas (described as a gaseous mixture having hydrocarbons for heating value), they are not subject to the Commission's broad authority over the construction and operation of natural gas pipelines under the Natural Gas Act, 15 U.S.C. §§ 717 et seq. *Cortez Pipeline Company*, 7 FERC ¶ 61024. In 1981, the Interstate Commerce Commission (ICC), the predecessor agency to the Surface Transportation Board, ruled that Congress excluded all types of gas from its jurisdiction under former section 1(1)(b) of the Interstate Commerce Act, then 49 U.S.C. § 10501(a)(1)(C). *Cortez Pipeline Company–Petition for Declaratory Order–Commission Jurisdiction over Transportation of Carbon Dioxide by Pipeline*, 45 Fed. Reg. 85177 (Dec. 24, 1980); 46 Fed. Reg. 18805 (March 26, 1981). The Surface Transportation Board has not addressed the question of whether it has jurisdiction over CO_2 pipelines.

Most current and projected future CO_2 pipelines transport CO_2 as a supercritical liquid, so they are subject to regulation as hazardous liquids.

However, future projects may increasingly require transport of CO_2 in a gaseous state. While PHMSA does not currently have statutory authority to regulate the safety of the transport of CO_2 in a gaseous state, if those authorities were to arise, any regulatory activity associated with exercising those authorities would be subject to public notice and comment.

SDWA UIC Program

SDWA's UIC Program regulates the underground injection of fluids into the subsurface to prevent endangerment of underground sources of drinking water.[73] Supercritical CO_2 falls under the definition of "fluid" (40 C.F.R. § 144.3); thus underground CO_2 injection falls within the scope of the SDWA UIC Program and will require a UIC permit before injection occurs. In preparation for the commercial deployment of CCS, EPA proposed minimum Federal requirements for underground injection of CO_2 for purposes of geologic sequestration.[74] The proposal builds on experience from the existing regulatory program, which provides the technical framework, expertise, and experience for permitting CO_2 sequestration. The rule proposes a new Class VI UIC well type for injection of CO_2. The proposal applies to owners or operators of geologic sequestration wells that will be used to inject CO_2 into the subsurface for long-term sequestration. The proposed Class VI UIC well requirements address site characterization, area of review, well construction, well operation, site monitoring, post-injection site care, public participation, financial responsibility (through post-injection site care), and site closure. These proposed requirements are tailored to address the unique characteristics of CO_2, including its large volumes, buoyancy, viscosity, and corrosivity. The SDWA does not provide EPA with the authority to shift liability to a third party or to indemnify owners or operators; therefore, the owner or operator may remain liable for endangerment to USDWs from unintended migration of fluid movement even after site closure occurs under SDWA §1431, CERCLA, or tort law. The final rule is anticipated to be published in late 2010. Until the geologic sequestration rulemaking goes final and into effect, CCS will continue to be permitted under the existing SDWA UIC Program, including existing State primacy authorities. Current options for permitting UIC wells that inject CO_2 include Class I industrial, Class II EOR, or Class V experimental wells, depending on individual conditions.

SDWA provides States an option to assume primary enforcement responsibility, or primacy, to oversee injection wells in their State. States issue UIC permits for injection wells onshore and could implement those requirements for wells inside State territorial waters. EPA encourages States to assume primacy for Class VI wells because it believes that States may provide for a comprehensive approach to managing CCS projects by promoting the integration of sequestration activities under SDWA into a broader framework for managing CCS Furthermore, sequestration operations involve ancillary activities (e.g., pipeline operations, pore space ownership, land use rights, and surface access) for which States can call upon other authorities that exist at the State level (but outside UIC authority) to provide a more comprehensive CCS management approach. The Federal government will maintain a robust

[73] SDWA §1421, 42 U.S.C. § 300(h).

[74] 73 Fed. Reg. 43492 (July 25, 2008).

role in assuring that minimum Federal standards for GS wells in primacy States are met through periodic review of their UIC programs.

The SDWA UIC Class VI rule will be effective 60 days after the final rule is published in the *Federal Register*. Following final promulgation of the rule, States will have 270 days to submit a complete Class VI primacy application to EPA for review and approval. During this time, States with existing UIC primacy for all other well classes under §1422 of SDWA that receive Class VI permit applications may consider using existing authorities (e.g., Class I, Class II, or Class V), as appropriate, to issue permits for CO_2 injection for sequestration while EPA is evaluating their Class VI primacy application.

After 270 days from final promulgation, EPA will establish a Federal Class VI primacy program in States that choose not to seek primacy for the Class VI portion of the UIC Program within the approval timeframe established under § 1422(b)(1)(B) of the SDWA. EPA will publish a list of the States where the Federal Class VI requirements have become applicable in the Federal Register. States may not issue Class VI permits until their Class VI UIC Programs are approved. During the first 270-days and prior to EPA approval of a Class VI primacy application, States without existing §1422 primacy programs must direct all Class VI geologic sequestration permit applications to the appropriate EPA Region. EPA Regions will issue permits using existing authorities and well classifications (e.g., Class I, Class II, or Class V), as appropriate. If a State submits a primacy application after the 270-day deadline and the application is approved, EPA will publish a subsequent notice of the approval in the Federal Register.

CAA Monitoring, Reporting, and Verification

EPA has proposed reporting and recordkeeping requirements for owners and operators of CO_2 sequestration facilities.[75] CO_2 sequestration facilities would be required to develop and implement an EPA-approved, site-specific monitoring, reporting, and verification plan. This rule would not establish performance standards for CO_2 sequestration facilities but would require annual reporting of the amount of CO_2 sequestered. Under the proposal, reports would be submitted annually, with the first reports due to EPA in 2012 for CO_2 injected during 2011. A final rule is anticipated to be published in late 2010.

CERCLA

CERCLA, 42 U.S.C. §§ 9601 to 9675, may apply to certain releases from a CO_2 sequestration site of hazardous substances, or pollutants or contaminants that present an imminent and substantial danger into the environment. This means, among other things, that the President

[75] *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, Proposed Rule,* 75 Fed. Reg. 18576, 18578 (April 12, 2010).

may have response authority under CERCLA § 104, 42 U.S.C. § 9604, and liability may be established under CERCLA § 107, 42 U.S.C. § 9607.

From available information on the potential chemical composition of CO_2 injectate, it appears that under likely capture scenarios, the CO_2 could contain "hazardous substances" (e.g., arsenic and selenium). CO_2 sequestration projects would likely fall within the definition of a "facility" (as a site where a hazardous substance is deposited or stored), and owners and operators of CO_2 sequestration projects are among the persons covered by CERCLA that could qualify as responsible persons if a plaintiff were to incur cleanup costs. Consequently, CERCLA liability could apply, unless an owner or operator could establish a defense.[76] If CO_2 enters groundwater, it might also cause hazardous substances, such as some metals, to be dissolved by the groundwater from enclosing strata. If that constitutes a release of hazardous substances from a "facility," such as the strata, then the owner of that facility could be liable for any response costs caused by that release.

Various stakeholder groups and published studies have characterized potential CERCLA liability as a barrier to CCS deployment (GAO, 2008). To the extent that injected CO_2 streams fall within the scope of a permit under the SDWA UIC Program, EPA may find that owners and operators are exempt from CERCLA liability if the injection qualifies as a "Federally Permitted Release;" however, EPA may evaluate whether a statutory change is necessary to exempt CO_2 injectate. Because CERCLA plays an important role in ensuring that there are financial resources and an accountable party (or parties) able to respond to any release occurring during CCS activities, any analysis of statutory changes would need to address the potential need for alternative methods of providing for such capabilities.

IV.B.1.3 Selected Laws Applicable to Deployment of CCS on Federal Lands

This subsection focuses on key elements of the regulatory framework applicable to two of the largest holders of surface and subsurface rights on Federal lands: the Bureau of Land Management (BLM) of the Department of the Interior (DOI), which manages 253 million acres and 700 million subsurface acres, and the Forest Service of the Department of Agriculture, which manages 193 million acres. Provisions of Federal law, as discussed below, may allow the siting of pipelines for transportation of CO_2 and the sequestration of CO_2 on BLM and Forest Service lands.

Title V of the Federal Land Policy and Management Act (FLPMA), 43 U.S.C. §§ 1761–1771, authorizes BLM and the Forest Service to grant, issue, or renew rights-of-way to public and

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[76] There are four elements necessary to establish liability under CERCLA § 107(a) 42 U.S.C. § 9607(a): (1) there must be a release or threatened release of a hazardous substance, (2) the release must occur at a facility, (3) the release must cause the plaintiff to incur costs not inconsistent with the National Contingency Plan, and (4) the defendant must fall within one of the four categories of responsible persons. See Young v. United States, 394 F.3d 858, 862 (10th Cir. 2005).

private entities for pipelines and other systems for the transportation or distribution of liquids and gases (excluding those governed by the Mineral Leasing Act, 30 U.S.C. § 185 (MLA)), on public lands and Forest Service lands, subject to certain terms and conditions to protect specified social, aesthetic, and environmental values and Federal property and economic interests. See also 43 C.F.R. Part 2800. FLPMA also authorizes Federal agencies to hold a right-of-way for transportation or distribution of liquids and gases governed by the MLA. FLPMA does not require such rights-of-way to be constructed, operated, or maintained as common carriers (i.e., transporting CO_2 on a non-discriminatory or open access basis). BLM also has the authority under the MLA to authorize rights-of-way to business entities for pipelines carrying CO_2 from a natural gas stream across BLM lands or Federal lands administered by two or more Federal agencies. Such pipelines must be constructed, operated, and maintained as common carriers with certain limited exceptions, and Federal agencies are not included among qualified applicants. Due to the vast tracts of Federal lands in the western United States, many CO_2 pipelines may cross Federal lands and need a Federal right-of-way, even if a proposed sequestration site is located on non-Federal land.

No provision of FLPMA expressly authorizes the sequestration of CO_2 on public lands; however, subsection (a)(2) of § 501, which is applicable to BLM and the Forest Service, authorizes rights-of-way for transportation and distribution of certain gases and liquids "and for storage and terminal facilities in connection therewith."[77] Subsection 501(a)(7) authorizes rights-of-way for such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through such lands. Section 302(b) of FLPMA also provides BLM with authority to undertake any use and development of public lands not specifically forbidden by law and not authorized by other laws or regulations. See also 43 C.F.R. § 2920.1-1. The MLA provides authority to lease lands for the extraction of minerals; however, it does not authorize disposal of wastes, except those arising from lease operations. There is no MLA provision analogous to § 302(b) of FLPMA that might provide authority for CO_2 sequestration.

Section 202 of FLPMA, 43 U.S.C. § 1712, requires that BLM prepare resource management plans to provide for the use of the public lands and that management be on the basis of multiple use and sustained yield. Regulations at 43 C.F.R. 1610.5-3 require that all future resource management actions conform to the plans. Similar, though not identical, requirements exist for the Forest Service through the National Forest Management Act, 16 U.S.C. §§ 1600-1614. Preparation of the plans involves considerable public participation and compliance with the

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[77] Where the source of CO_2 was a natural gas stream, section 501(a)(2) was found to be inapplicable to the transportation of CO_2. Exxon Corp., 97 IBLA 45 (1987), aff'd, Exxon Corp. v. Lujan, 730 F. Supp. 1535 (1990), aff'd, 970 F.2d 757 (10th Cir. 1992). A right-of-way under section 28 of the MLA, 30 U.S.C. 185(a), was found to be appropriate. Thus, the origin of CO_2 may be important in identifying whether Title V provides authority for CO_2 storage.

NEPA, Endangered Species Act (ESA), National Historic Preservation Act (NHPA), and other laws. The requirements of the SDWA UIC, CAA, RCRA, CERCLA and other provisions of law applicable to sequestration on private lands are also generally applicable to sequestration on Federal lands.

See Appendix M for a discussion of siting considerations for CO_2 pipelines across Federal lands, including the potential use of energy corridors.

IV.B.2 Legal and Regulatory Challenges

As the CCS industry matures, the existing set of regulations is likely to face a variety of management and implementation challenges. The unique characteristics of CO_2 sequestration, uncertainty around technology development, variety of industry and regulatory actors, and potential scale of injection operations all present uncertainties and potential areas that could stress the application of existing regulations and resources. These considerations may warrant additional actions that the Federal government could take to strengthen the existing regulatory framework and its implementation.

The Task Force evaluated whether the existing regulatory framework, or elements thereof, could be integrated into a single framework for governing CCS and found that there are differences in scope, implementation approaches, administrative procedures, compliance assurance, and enforcement mechanisms, among other issues, that present challenges for creating a unified framework.

Regulatory requirements and implementing agencies will differ depending on conditions such as the location of the sequestration project. Factors that may affect the regulatory requirements and implementing agencies include type of project (e.g., experimental vs. commercial), source of funding (e.g., government vs. private), land ownership (e.g., public vs. private), location of injection wells (e.g., onshore, offshore but generally within 3 miles, offshore and generally beyond 3 miles), type of sequestration reservoir and/or project purpose (e.g., saline vs. oil field), purity of CO_2 stream, and source of CO_2 (e.g., power generation vs. industrial processes).

Enhanced coordination on legal and regulatory issues will be needed between Federal agencies as well as between the Federal government and the States. Stakeholders noted that State UIC programs have faced resource limitations in implementing the SDWA UIC Program. Significant increases in permit applications could overwhelm the capacity of both EPA and primacy States. While some States may be able to take on many of these challenges, others may have difficulties in certain areas such as reviewing and validating the results of complex computational models. As can be expected in a nascent industry, regulatory agencies will be challenged to gain the expertise needed to ensure they have capacity to adequately implement the program, and avoid lengthy delays in permitting.

Permitting and regulatory authorities may face challenges in terms of training and workforce capacity. CO_2 pipeline infrastructure deployment would be aided through training and designated resources to assist Federal, State, and local agencies with permitting, compliance, and public outreach, as well as for training first responders. For sequestration, stakeholders have expressed concern that States may not have sufficient technical resources in very specialized areas related to CO_2 sequestration that will be critical in the review of permit applications, such as new site characterization technologies, specialized CO_2-compatible well construction techniques, computational modeling, geochemistry, injection formation dynamics, and financial responsibility. States may not have sufficient staff to review a large number of Class VI permit applications, write permits, and review and enforce those permits.

Several challenges need to be addressed for onshore Federal lands to be fully used in an efficient and effective manner for CO_2 sequestration. First, the BLM and the U.S. Forest Service (USFS) currently lack clear authority for long-term CO_2 sequestration. Second, the authority that may be applicable does not address issues of long-term liability, stewardship, ownership of pore space, and the appropriate rent for the use of Federal pore space. As discussed in Section IV.C, CO_2 sequestration presents unique challenges related to long-term liability and stewardship, since it is contemplated that the CO_2 will remain stored indefinitely, perhaps for hundreds or even thousands of years. BLM and USFS current authorities do not deal with these unique issues. Third, sequestration on split estate lands also presents complications due to ownership of pore space and limitations that may need to be placed on surface and subsurface uses to ensure integrity of sequestration.

Moreover, amendments to resource management plans may be needed prior to authorizing any sequestration projects on public lands. These plan amendments often involve complex and lengthy compliance with NEPA 42 U.S.C. § 4321, the ESA, 16 U.S.C. § 1531, Clean Water Act, 33 U.S.C. §1251, and the NHPA, 16 U.S.C. § 470, as well as agency and Tribal consultations. There are also several opportunities for public comment.

In addition, BLM does not currently have a statutory or regulatory mechanism that directly addresses the assurances sought by current applicants for a noncompetitive preference right to develop future CCS projects after initial site characterization studies. Other applicants may seek the same assurances.

Finally, authorizing the use of onshore Federal lands for geologic CO_2 sequestration may potentially conflict with other subsurface uses, including existing and future mines, oil and gas fields, coal resources, geothermal fields, and drinking water sources. CO_2 sequestration could also have potential impacts on other surface land uses and programs such as recreation, grazing, cultural resource protection, and community growth and development.

IV.C Long-Term Liability Regarding Storage of CO_2

IV.C.1 Overview

Many stakeholders have expressed the view that legal and regulatory liabilities constitute barriers to the widespread cost-effective deployment of CCS. This section examines legal and regulatory mechanisms and summarizes options for government intervention to address liabilities associated with the long-term underground sequestration of CO_2. The subsection begins by providing background and an overview of long-term liability issues. It then discusses considerations that are relevant to deciding whether governmental actions to address such liabilities are required, and what types of interventions are appropriate, if any. It then analyzes the present legal regime relating to long-term liabilities.

There are two major categories of liabilities: (1) obligations to perform (e.g., to comply with regulatory standards); and (2) obligations to compensate parties for various types and forms of legally compensable losses or damages. Although financial responsibility is required until closure of the CO_2 sequestration site, the focus of this section is "long-term" liabilities arising during the post-closure period. The Task Force focused its analysis on long-term liabilities because the risks during the operational and post-closure monitoring period of CO_2 sequestration projects are similar to current industrial activities that can be underwritten in the financial and insurance sectors. Liabilities associated with the capture or transportation of CO_2 do not fall within the scope of this discussion. The discussion below also does not address liability or stewardship of CO_2 sequestration sites before the end of the post-closure phase. Ensuring adequate stewardship and financial responsibility during that period is, however, an important consideration in ensuring that long-term liabilities do not arise later.

IV.C.1.1 Existing Laws and Regulations Related to Long-Term Liability

Existing legal authorities include a range of approaches to liabilities related to long-term CO_2 sequestration. As noted below, although there is no comprehensive, integrated Federal framework specifically directed to defining or allocating long-term liability, there are a number of Federal and State laws that bear on long-term liability. The discussion below provides a summary of existing authorities as they relate to long-term liability; those authorities are analyzed in more detail in Section VII.

Under the SDWA, 42 U.S.C. §§ 300f-300j, for example, EPA has issued a proposed rule through its SDWA UIC Program to require owners or operators of underground geologic sequestration facilities to demonstrate financial responsibility through post-injection site care. See 40 C.F.R. Part 146. The proposed rule provides for owners or operators of sequestration sites to demonstrate and maintain financial responsibility to ensure that resources will be available to address adverse situations related to underground sources of drinking water throughout the lifetime of a project, even if the operator experiences financial difficulty. The

UIC regulations specify that owners or operators must ensure that resources are available to address all needed corrective action on wells in the area of review, injection well plugging, post-injection site care and site closure, and emergency and remedial response.[78] Operators must also review and adjust the financial responsibility cost estimates at least annually to account for any amendments to the required project plans for the above activities or to address inflation or other changes to the estimated costs. Financial responsibility under this proposed rule will remain with the owner or operator through post-injection site care. Long-term liability (i.e., liability that addresses the time period after site closure is authorized) is outside of the scope of EPA's regulation.

Under the proposed rule, the owner or operator would continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years following the cessation of injection, or until (either more or less than 50 years) the owner or operator can demonstrate to the Director[79] that their geologic sequestration project no longer poses an endangerment to USDWs. Once all regulatory requirements have been met, the owner or operator will be released from SDWA requirements, and therefore, liability for enforcement under §1423 of that Act. SDWA does not provide authority to shift liability under the Act to another entity other than UIC owners or operators. In addition, an owner or operator may be liable under §1431 of the SDWA after site closure has been approved if there is unanticipated migration that threatens imminent and substantial harm to a USDW. In addition, tort and other remedies will continue to be available after site closure. Other Federal environmental statutes, e.g., CAA, 42 U.S.C. §§ 7401-7671; CERCLA, 42 U.S.C. §§ 9601-9675; and RCRA, 42 U.S.C. §§ 6901-6992k, potentially apply as well to the risks created by the long-term sequestration of CO_2.

Additionally, a number of States have begun to establish local regimes for long-term liability transfer. The Task Force has not undertaken a comprehensive review of State law, but a number of examples are illustrative. Four States (Louisiana, Montana, North Dakota, and Oklahoma) have developed a "certificate of completion" model whereby the operator of a geologic sequestration site can transfer title and liability to the State after demonstrating to the relevant agency that the site is stable for a certain period of time after the last CO_2 has been injected and the site has been closed; until the time of transfer, the operator remains liable for damages related to CO_2 migration or leaks. Two States (Illinois and Texas) have accepted liability for certain CCS pilot projects within their borders. Two other States (Washington and Wyoming) have disclaimed State liability from long-term CO_2 sequestration unless otherwise

[78] 40 C.F.R. 146.85.

[79] The Director is the person responsible for permitting, implementation, and compliance of the UIC program. For UIC programs administered by EPA, the Director is the EPA Regional Administrator; for UIC programs in Primacy States, the Director is the person responsible for permitting, implementation, and compliance of the State, Territorial, or Tribal UIC program.

specified by law. Additionally, two States (Kansas and Utah) have given hereto-unexercised regulatory authority to State administrative agencies, which may encompass the ability to address long-term liability.

IV.C.1.2 Stakeholder Views

Experts and stakeholders have expressed a range of views as to whether long-term liability is a barrier to commercial deployment of CCS. A number of stakeholders, particularly from private industry, have said that they consider long-term liabilities to be a key barrier to the commercial deployment of CCS. They expressed the concern that these liabilities are difficult to quantify on corporate balance sheets. Although the technical community believes that many aspects of the science related to geologic storage security are relatively well understood,[80] the time frame over which the long-term risks might exist is long, in the hundreds or thousands of years. To the extent that some uncertainty remains, that uncertainty is magnified by the time frames involved. Even after discounting this long-term risk to net present value, stakeholders believe that there is significant remaining uncertainty, and said that businesses are uncomfortable undertaking these long-term risks. Moreover, even apart from the actual likelihood that long-term liabilities will accrue, these stakeholders have said that such liabilities are novel enough that businesses may encounter difficulties in reflecting them in their accounting statements. Such statements will be subject to the audit committee of a company's board of directors, as well as review by its independent auditor. If the company is a public company, the chief executive officer and the chief financial officer will be required by the Sarbanes-Oxley legislation to sign a certification that based, on the officer's knowledge, corporate reports do not contain any untrue statement of material fact or material omissions.[81]

A second set of issues involves the availability of insurance for long-term risks. Insurers state that they are able to issue coverage for the period through site closure.[82] But underwriting the risk over the "long-term" or perpetual time horizon of underground sequestration may present a challenge to both the private and public sector. Some entities in the private sector are concerned over insurance requirements because the long-term horizon of geologic sequestration and its novelty appear to be limiting the availability of coverage. Insurers state that they currently will not write policies to cover post-closure risks associated with CCS. Although they will underwrite conventional operational risks, they explain that currently they

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[80] See Section III.C.2.3.

[81] Communications from representatives of the Coal Utilization Research Council, North American Carbon Capture and Storage Association, and AEP.

[82] See, e.g., communication from representative of Zurich Financial Services. Zurich stated, however, that it would not issue coverage for the cost of replacing CO_2 lost from a storage reservoir even in the shorter-term period, in light of the uncertainty as to the future per tonne price of CO_2 under future legislation. Thus, if a market for CO_2 comes into existence through future legislation, it will become necessary to determine whether insurance for this type of risk has become available, and, if not, whether other financial assurance mechanisms will be needed.

are not able to estimate the costs of such policies, their typical business does not encompass claims that may not arise for centuries, and they are not institutionally suited to underwrite risks arising in such a long time frame. Furthermore, without insurance or a comparable risk management mechanism, private lending facilities may not be willing to extend credit to finance the construction of facilities conducting CO_2 sequestration.[83]

A third set of issues identified by commentators involves the potential "joint and several" nature of the liabilities at issue (such as CERCLA liability).[84] Under joint and several liabilities, it is possible that every entity that generates CO_2 and contributes it to a particular reservoir could be held liable for the entire cost of any liability that ensues, particularly if no other party is available to pay those costs. This concern is particularly acute for shared reservoirs and in instances in which a CO_2 stream is acquired from third parties, because of the larger number of parties that could potentially be involved in such transactions.

Other stakeholders and experts have questioned the substantiality of these concerns. They have said that a description of long-term liabilities associated with CO_2 sequestration is ordinarily sufficient for recognition purposes in audited financial statements where an entity cannot establish a quantified estimate of such liabilities, and that therefore quantifying long-term liabilities on corporate balance sheets is overstated.[85] Some stakeholders have also expressed concern that relieving businesses of long-term risks could undermine the incentives to those businesses to take appropriate precautions in their activities (Center for Biological Diversity et al., 2010).[86] Moreover, in other circumstances, similar long-term risks do not appear to deter businesses from participating in commercial activities. For example, businesses handle hazardous materials notwithstanding the potentially indefinite nature of CERCLA liability. Material sent to a landfill can likewise generate indefinite liabilities under CERCLA. (One possible distinction, however, is that insurance may be available in those settings.)

IV.C.1.3 Risks, Harms and Potential Liabilities Associated With CCS

The long-term sequestration of CO_2 gives rise to an assortment of potential risks, harms, and legal liabilities. Potential categories of risks include scientifically identifiable risks, e.g., the migration of CO_2 in ways that are scientifically understood; anomalous or unpredicted

[83] Communication from GE Financial Services.

[84] Communications from Coal Utilization Research Council, North American Carbon Capture and Storage Association, and AEP Representatives.

[85] See, e.g., S. 1013, the statement of Chiara Trabucchi on the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2009, before the S. Comm. on Energy & Natural Resources, 111th Cong. (Trabucchi, 2009). In addition, under Financial Accounting Standards Board requirements, if an entity determines that it cannot reasonably estimate fair value of an environmental liability, an entity would recognize the liability and include a description of the obligation in its audited financial statements (Lee and Trabucchi, 2008).

[86] Communication from Center for Biological Diversity et al. to Senator Reid (May 17, 2010).

behaviors, e.g., unpredicted geophysical or chemical reactions; operator or regulatory errors, mistakes, or oversights; falsifications and illegal conduct; policy changes; and acts of God.

As discussed in Section III.C, present scientific research has concluded that there is substantial evidence that the great majority of CO_2 in a sequestration facility will remain in place for extended periods (centuries, millennia, or longer). This research assumes that the injection site is chosen properly, injection operations are conducted accurately, the site is monitored adequately, and closure and post-closure operations are conducted appropriately. To the extent that there is any significant risk in CCS activities, it is likely to arise from human error in one of these activities. Possible sources of such error are discussed in Appendix H.

Section III.C also explains that the risks associated with underground geologic sequestration of CO_2 are expected to be highest during the operational phase of the project when insurance is available, and then decrease over time. In order for a project operator to close a sequestration site, in accordance with Federal and State laws, the operator would have to make a demonstration that the risks were at a very low level.

The above risks can give rise to a variety of potential harms.[87] One issue is direct harm from CO_2. Exposure to CO_2 released into the air or water may have injurious toxicological effects on human and animal life or on surface waters (depending on concentration, scale, and other factors). Another concern is groundwater harm. CO_2 migration underground can cause toxic substances (such as lead or arsenic) in surrounding rocks to dissolve into groundwater, through acidification or other mechanisms. Groundwater could also be contaminated by brine displaced by CO_2 injection. CO_2 migration may also harm mineral deposits.[88] Finally, harm to the climate (or loss of benefits of sequestration) is associated with the release of CO_2.[89]

Potential legal liabilities associated with the above harms include both performance and compensatory liabilities, as noted above. Performance liabilities include stewardship obligations of private entities, States, or the Federal government under environmental regimes (e.g., the proposed SDWA UIC Program described below), which may range from monitoring to cleanup or other obligations. Compensatory liabilities include tort liabilities under Federal or State law pursuant to various personal injury or property damage theories, including trespass, nuisance, negligence, and abnormally dangerous activities/strict liability; liabilities arising from government action constituting a taking of private property; contract liabilities between parties to a

[87] Additional discussion of potential harms is found in Section III.C.

[88] To the extent that a harm would involve impairment of a property right, e.g., in pore space, it is addressed in Section III.C.5.7. Tort claims are within the scope of the present section.

[89] There are also additional potential harms that are largely associated with the injection phase, rather than with long-term stewardship. These include surface shifts (ground movement) and induced microseismic activity, which is generally at a scale that would not be detectable except with scientific equipment. They are noted here for completeness.

sequestration transaction; and liabilities of site operators, on indemnification or other theories. Finally, if future legislation imposes a price on CO_2 emissions, a release of CO_2 could give rise to a claim for the replacement costs of lost CO_2.[90]

It bears noting that EOR activities in oil- or gas-producing areas for a number of years have included underground injection of CO_2 as a means of re-pressurizing the reservoir and increasing oil and gas recovery. EOR operations are widespread and appear to be able to proceed without being constrained by concerns about long-term liability.[91] This raises the question of why CCS activities, which involve underground injection of CO_2 in a manner very similar to EOR activities, should be chilled by long-term liability concerns. There are, however, a number of potential distinctions. First, the process of producing oil reduces underground pressure levels, so that addition of CO_2 as part of EOR operations may not lead to pressure levels as high as at a CCS site. Because high pressures are one source of risk, EOR may be less risky than CCS. Moreover, at the end of an EOR operation, much of the CO_2 is removed from an EOR site for use in other fields. Although some CO_2 typically remains in the reservoir, this also means that EOR operations may be comparatively lower risk. Finally, CO_2 has been used for EOR purposes for decades, which has helped to reduce technical and economic uncertainties.

IV.C.2 Policy Considerations for a Long-Term Liability Arrangement

In Section IV.C.1.1, the Task Force outlined the present legal rules governing long-term liability. Then, in Section VII, the Task Force outlines seven possible approaches for addressing long-term liability. The analysis of these approaches, and the implementation of any particular approach, should turn on a full analysis of risks, costs, and benefits. Several policy considerations also could guide the selection of the most appropriate option or combinations of options. These policy considerations include encouraging CCS deployment, minimizing moral hazard,[92] minimizing negative impacts on existing insurance markets and sources of financing,

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[90] A future CCS regime is likely to incorporate financial incentives to sequester CO_2, whether in the form of a cap-and-trade system or in some other program. Thus, if CO_2 escapes sequestration, there is likely to be a cost of replacing the sequestration capacity in question, whether a per-tonne cost based on the then-current price of CO_2 credits, or a cost of repaying the incentive amounts paid for sequestration, or some other cost.

[91] EOR operations generally occur where a field has been "unitized." With unitization, oil or gas field leases for resource development are combined, thereby creating a field-wide operation. In this circumstance, liability is generally removed as a concern as between the owners of producing interests because production and profits are shared by all unit members and the entire field is managed to optimize resource recovery. In EOR operations that have not been unitized, liability is usually imposed on the operator for mineral loss on the basis of trespass and nuisance. *See* (University of Houston Law School, 2008).

[92] "Moral hazard" is an economic behavioral term used to describe a situation where the risk of an event may increase due to actions the responsible party takes because it is partially insulated from being held fully liable for resulting harm and attendant damages. Moral hazard is a concern with any system of risk pooling because corporations are not liable for the entire costs of their own accidents. ("Risk pooling" is a general term for a wide range of mechanisms, from insurance to liability funds or other arrangements). (Hamilton, 1980).

providing for appropriate long-term stewardship of sequestration sites, being sensitive to federalism concerns at the State level and the possibility that some approaches may be better handled at that level, ensuring that those who are harmed can be compensated, and equitably distributing the costs of liability (e.g., determining whether liability costs should fall on those entities that generate CO_2; on sequestration facility owners/operators; on utility ratepayers, in the case of CO_2 generated as a byproduct of electricity generation; or on the taxpayers generally).[93]

Whatever approach is adopted should take into account the continued need for long-term stewardship, defined as oversight of an underground geologic sequestration facility after the post-closure period. Due to the permanent nature of long-term stewardship, some have argued the need to establish a public entity responsible for the long-term stewardship of underground geologic sequestration sites once the period of commercial activity at the site (including the generation of any revenue) and the term of regulatory financial assurance have passed.[94]

Another policy consideration is whether, in order to foster the CCS industry, different liability rules could be applied to early projects versus later projects. Some commentators have questioned whether incentivized treatment of early projects has a reasonable prospect of yielding data helpful in the design of later projects, in light of the long time horizons involved.

Finally, in designing a comprehensive framework for regulating CCS activities, the most critical features relating to long-term liability will be those that serve to prevent such liability from occurring. Appropriate site selection is especially important in minimizing risks of CO_2 sequestration activities. Also critical are robust monitoring, regulatory oversight, and enforcement. To reduce the potential moral hazard, liability assumption or transfer, if warranted, could be conditioned on strong siting and operational standards as well as the environmental performance of the CO_2 sequestration project through a site closure certification process to ensure that the site does not pose an environmental, health, or safety risk.[95] These requirements are anticipated to be addressed in EPA's final geologic sequestration rulemaking under SDWA.[96]

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[93] Although this discussion is focused on long-term liability, a similar set of considerations apply to any analysis of shorter-term liabilities, which are likewise affected by considerations of moral hazard and the other factors discussed in the text. Notably, however, insurance is available for shorter-term liabilities. The desire to avoid undercutting private insurance markets may therefore be the dispositive factor as to such liabilities. A number of commentators have taken the position that CCS operators should rely on private insurance while a storage site is active. See, e.g., CCS Regulatory Project (2009a).

[94] See Section VIII for more discussion.

[95] A number of experts have made comments to this effect. See World Resources Institute, (2008).

[96] Under the UIC proposal, EPA would establish detailed site closure requirements. 73 Fed. Reg. 43492, 43540-1. Specifically, owners or operators would be required to prepare, maintain, and comply with a plan for post-injection site care that includes monitoring of pressure data in the injection area and reporting of monitoring data. After

Any policy that allows a party to submit a demonstration of financial responsibility in the form of commercial liability insurance, pooled fund, or bond pool could foster moral hazard if it encouraged undue or irresponsible risk-taking by insureds (Zimmerman, 1990). Any of these measures should therefore be linked to monitoring, enforcement, and other accountability mechanisms to deter such conduct. Financial responsibility[97] requirements imposed to address liability risks, either shorter- or long-term, should also be linked to a site-specific risk assessment that attempts to value potential liabilities and future costs (including such costs as the cost of long-term monitoring and any necessary remedial action). Financial responsibility mechanisms could be held by an individual owner/operator or pooled across multiple owners/operators. If held by individual owners/operators, this could encourage responsible site operation by tying the use of mechanism funds directly to the actions of the CCS project operator (Wilson et al., 2009). If pooled, they could appropriately be based on a site-specific risk assessment (and thus would potentially vary between sequestration facilities, rather than being uniform across such facilities) (Dooley et al., 2010b). These risk assessments, and the associated fees, could be reevaluated periodically based on any new information about the site in question (as well as about CCS operations more generally), which will help to ensure that available funds are tailored to actual needs and to provide an adaptive management framework for CCS operations.[98]

There are potential negative implications of changing existing liability arrangements, depending on how the relevant programs are structured. As has been explained in this report, Federal involvement in CCS liabilities has the potential to raise moral hazard and equity issues. In this context, if stakeholders know they will not face liability, such a circumstance arguably may create a disincentive to proceed in a safe and environmentally sound manner. Non-governmental organization (NGO) commentators have highlighted this concern (Center for Biological Diversity et al., 2010). The development of a far-reaching program to address private liability could also be misinterpreted as a signal to the public that the technology is too dangerous to use or as a "bailout" of private industry with an attendant socialization of

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injection has ceased, owners and operators must monitor the site to show the position of the CO_2 plume and pressure front and show that drinking water supplies are not being endangered. Monitoring must continue for at least 50 years or until the geologic sequestration project no longer poses an endangerment to underground sources of drinking water. Prior to closing a site, the owner or operator must provide a report containing a survey plot indicating the location of the injection well relative to permanently surveyed benchmarks; documentation of appropriate notification to governmental entities that have authority over drilling activities so that they may impose appropriate conditions on subsequent activities in the area; and records that reflect the nature, composition, and volume of the CO_2 stream.

[97] Financial responsibility requirements are designed to ensure that owners and operators maintain adequate financial resources to fulfill their current and future environmental obligations. See (EPA, 2008).

[98] *See generally* S. 1013, the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2009 Before the S. Comm. on Energy & Natural Resources, 111th Cong. (2009) (statement of Chiara Trabucchi, Principal, Industrial Economics Incorporated).

significant potential environmental impacts and/or widespread environmental contamination. Liability caps and indemnities may be seen as indirect subsidies to CCS developers, possibly at the expense of investment in alternative technologies, and Federal assumption of CCS liability may create a precedent sought by other industries. Also, except where a regulatory program is specifically designed to foster private insurance, government action could be read to undermine private insurance markets.

IV.D Public Information, Education, and Outreach

IV.D.1 Overview

Public awareness and support have been recognized as critical components in the development of new energy infrastructure, and are widely viewed as vital for cost-effective CCS deployment (IPCC, 2005; CRS, 2008; IEA, 2009c). Lack of public acceptance can serve as a barrier if project developers fail to recognize the importance of integrating public engagement and education throughout the lifecycle of their project. Support or opposition for new technologies can have a big impact on their deployment: for example, public opposition has been cited as a key reason that no new refineries have been built and no nuclear plants have been ordered since the 1970s (CRS, 2008). Whether or not the public and local communities will support or oppose commercial-scale CCS projects is to a large extent unknown. Most studies, in fact, have shown that the public is largely unaware of CCS (IPCC, 2005; Johnsson et al., 2010; Malone et al., 2010).

Public perception of the risks associated with CCS can be significant and—as demonstrated during previous CCS projects—there is the potential for concern by local communities that they will be subjected to high risks while others derive the benefit. Early experience has shown that local opposition can cause or contribute to project delays and cancellations. Geologic sequestration projects planned in Spremburg, Germany and Greenville, Ohio were cancelled, in part, due to concerns from residents about escaping CO_2 endangering public health, reduced property values, and induced seismicity (Associated Press, 2009; Slavin and Alok, 2009). Residents of Barendrecht, Netherlands have expressed vocal opposition to a nearby sequestration project, causing project developers to look for alternative sites (Pals, 2009; Voosen, 2010).

Other CCS projects in the United States provide examples of positive experiences with public outreach and engagement. The Regional Carbon Sequestration Partnerships (RCSP) have managed the implementation of 21 small scale and several large scale CO_2 sequestration projects that have either been completed or are currently injecting CO_2 in deep saline, coal seams, or oil and gas fields. The participants from these projects have worked to consolidate their experiences and lessons learned on community engagement and acceptance into a best practices guide for public outreach and education (DOE, 2009).

In order for CCS to be successfully deployed at scale it will be critical to address public perceptions of CCS technologies, their risks, and their role in reducing GHG emissions. The primary avenues for such work are through outreach and education efforts, and through direct engagement with project communities. When done successfully, these efforts can help identify key issues, foster public understanding, and build trust between communities and project developers. The Federal government can play a useful role in such efforts, though much of that role will be in providing information for use by project developers, project communities, and the general public. Stakeholder groups could include residents; local, regional, and national business owners and organizations; labor and related organizations; environmental organizations; environmental justice organizations; employers; employees; academia; emergency responders; media; policy leaders; and other institutions.

IV.D.2 Elements of a Successful Outreach Strategy

Under the RCSP, DOE has been engaging with local communities to educate and inform them about planned pilot and demonstration projects in their areas. DOE's *Best Practices for Public Outreach and Education for Carbon Storage Projects* presents lessons learned through the planning and implementation of CCS projects, as well as best practices for community engagement. The World Resources Institute also has issued recommendation for regulators, project developers, and local decision-makers for engaging with communities. Many of these recommendations center on common themes:

- Integrate public engagement and outreach efforts into core project management systems, from the earliest possible point in time;
- Provide information about CCS, its risks, and the laws or requirements that are in place to minimize risks to human health or the environment;
- Provide easily accessible information about CCS projects;
- Engage the community during the planning stage and maintain engagement throughout the project lifetime;
- Communicate the potential benefits of future CCS projects, such as job creation and stimulus to the local economy, and decreases in local air pollution;[99]
- Provide local communities with several opportunities to raise concerns, and address those concerns in a timely manner;

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[99] Advanced technologies such as IGCC are more efficient and virtually zero emissions when coupled with carbon capture. Replacing existing plants with IGCC facilities would results in reduced air emissions of criteria pollutants. In retrofits of existing plants, since the ability to capture CO_2 from a power plant will require the plant to install NO_x and SO_x capture systems reducing the emissions of these criteria air pollutants. In oxyfuel plants it is expected that all criteria pollutants will be reduced. (MIT, 2009).

- Focus on creating an open dialogue with the public, as opposed to a one-sided conversation;
- Create mechanisms and systems to monitor and gauge public reactions and opinions; and
- Discuss why CCS is important (climate risks, need for sufficient and reliable energy).

IV.D.3 Status and Key Gaps

Several key gaps must be addressed to facilitate public acceptance of CCS. Public acceptance could be improved by initiatives designed to better understand public acceptance of CCS and engage with the public.

There are a number of claims that the public will be largely opposed to CCS; in reality, the public is largely unaware of CCS (Malone et al., 2010). Public engagement activities performed under the RCSP pilot projects are beginning to yield a better understanding of community concerns, as well as successful strategies for engagement. In general, there is a significant need to better understand how the public will view CCS, what their concerns will be, and how they can be addressed.

There is a considerable lack of awareness and understanding of CCS and associated risks. Early engagement and communication will be essential, as misinformation and misperceptions can quickly spread; once initial opinions are formed, they can be slow to change (Ashworth et al., 2010). Studies have shown that public perceptions about CCS become more positive with more information, and NGOs are trusted most as conveyers of this information. The public is less likely to trust information coming from a single source, particularly coming solely from industry or government (Shackley et al., 2009; Ashworth et al., 2010). The general public will primarily be concerned about big-picture issues: levels of government funding, impact on electricity prices, risks of the technology, and the benefits of CCS compared with other energy technologies.

Communities near planned projects will require targeted engagement. These communities may have concerns about how a particular project will affect them: risks to health, drinking water, property values, as well as benefits in the form of jobs, stimulus to the local economy, and potential reductions in air pollution. Communities could play a significant role in how and whether new energy infrastructure projects are constructed. Such communities can get involved through various means, including site selection and approval, permitting processes, litigation, or less formal means such as protests and media campaigns. In the United States, CCS projects implemented to date have been met with support by project communities, with a few exceptions.

Promoting meaningful involvement for disproportionately impacted populations requires special efforts. Involving communities already burdened by human health and environmental concerns can be particularly important in preventing unintended negative consequences. Minority, low-income, Tribal, and other populations historically under-represented in environmental decision-making present challenges that are different from those presented by the general public. These communities often have a wide range of educational levels, literacy, access to the Internet, and proficiency in English. It will be necessary to tailor outreach materials to ensure that they are concise, understandable, and readily accessible.

V. Framework for Addressing Market Failures

As identified in Section IV.A, two key market failures impede the pathway to CCS deployment. The Administration's proposal to establish a market signal by pricing GHG emissions would resolve the most significant market failure by internalizing the cost of emissions. The second market failure of knowledge spillovers from technology development remains, but is already being addressed at least in part by current Federal incentives for CCS. A key objective of this section is to outline a framework for assessing what, if any, additional drivers and incentives may be warranted beyond those proposed or already in place.

Several factors serve to widen the gap between the social and private returns to CCS technology development relative to those experienced by other low-carbon technologies at a comparable stage of development. The deployment of CCS, unlike other low-carbon technologies, is entirely dependent on adoption of measures to limit greenhouse gas emissions, adding to uncertainty for private investors. As outlined in this report, the widespread deployment of CCS also hinges on other unresolved non-economic issues, which again reduce expected private returns to CCS development. Finally, the global nature of the externalities associated with greenhouse gas emissions and international markets for CCS further increase the expected gap between private and social returns to CCS development.

The fundamental balance that must be achieved in determining the nature and extent of such incentives is between ensuring the *availability* of a cost-effective technology (as a hedge against risk to the economy posed by climate change) and *over-investing* in a technology, leading to inefficient allocation of scarce public resources to subsidize what should be private sector actions (which distorts economic decision-making and displaces lower-cost solutions).

Determining the relative efficacy and cost-effectiveness of potential drivers and incentives that may spur CCS technology deployment is challenging. Careful consideration should be given to any economic costs associated with such policies. This section summarizes existing incentives for the development of CCS and provides principles for evaluating the extent to which additional drivers or incentives may be considered. The ultimate objective of public investment in CCS technology is to support the achievement of GHG emission reduction goals at the lowest cost possible, and these options are discussed with this objective in mind.

V.A Framework for Incentivizing CCS Technology for Public Gain

There are a number of public policy tools that can be used to channel investment to incentivize the commercialization of CCS technology. The following section describes the context in which these incentives operate and how they should be assessed. Later sections offer more detail on a suite of existing and potential incentives and drivers for CCS technology.

V.A.1 Key Principles for Assessing CCS Drivers and Incentives

Any assessment of policy drivers and incentives should be grounded in the context of the related policy goal. Table V-1 shows several key principles to which incentives for CCS should adhere. In this report's context, the purpose of drivers and incentives is to overcome those market failures that impede widescale, cost-effective availability of CCS consistent with market signals, including a price on GHGs. This goal is not easily translated into a measure of capacity deployed or GHG abated, and for good reason, as the market will be the determinant of CCS capacity deployed, and GHG abatement will be governed by the cap on emissions. The incentives and drivers to be considered should address CCS deployment not as an end in itself, but as a means to achieve cost-effective abatement of GHG emissions.

Table V-1: Key Principles of Public Policy Tools that Address CCS Deployment Market Failures

Incentives should:	
1	Reflect the nature and magnitude of the specific market failure targeted;
2	Adjust to changing circumstances and information over time;
3	Enable maximum possible flexibility of private sector response;
4	Be coordinated with and reflective of interactions with other incentives; and
5	Maximize achievement of policy objective per dollar of taxpayer and consumer cost.

Reflect the nature and magnitude of the market failure: Potential drivers and incentives should be assessed singly and together on the basis of their ability to address a particular market failure. The scale and scope of an incentive in this context should be matched as closely as possible to the scale and scope of the identified market failure impeding widespread cost-effective commercial availability. For example, an incentive addressing market failures related to CCS should not be so broad as to affect the cost or financing of already commercialized, mature technologies for which spillovers are likely to be very small.

Adjust to changing circumstances and information over time: The criterion of scale is complex because the size of market failures impeding cost-effective CCS commercial availability is not only difficult to judge, but will also change over time as the technology matures. Consequently, even if it is properly scaled to initial conditions, an open-ended incentive that does not adjust to reflect changes in the targeted market failure would introduce inherently inefficient allocations of scarce public resources due to inflexibility of the policy tool. Thus, incentives should be assessed for their ability to re-scale over time, so that public investment channeled through the incentive structure keeps pace with changes in the magnitude of the market failure it is designed to address. Since economic incentives can create their own constituencies, making their reduction or removal politically difficult, policy makers should consider the conditions under which they should phase out prior to committing to providing them.

Flexibility of private sector response: To the greatest extent practical, incentives should allow the market to decide which particular technologies will be developed. Private investors with their own money at risk will have the right incentives and expertise to invest in technologies that are most likely to become commercially sustainable.

Coordinated incentives: Different incentives may address the same market failure to a greater or lesser extent, indicating the need to coordinate incentives. Uncoordinated, overlapping incentives are more likely to lead to over-subsidy, distortions in investment behavior, and a failure to properly scale public intervention to the targeted market failures. The need for coordination should be considered both in evaluating the possibility of multiple Federal incentives, and in evaluating Federal, State, and local incentives in light of one another. Transparency and coordination will also make it more feasible for policy makers to assess the effectiveness of CCS incentives.

Cost-effectiveness: Incentives and drivers should also be assessed for their ability to maximize achievement of policy objective per dollar of taxpayer and consumer cost. In pursuing this goal of cost-effectiveness, consideration should be given to relevant institutional details of the targeted markets, such as differences between publicly owned and investor-owned utilities, or differences between cost-of-service territory and competitive power markets. Properly targeted and scaled incentives help reduce the cost to taxpayers and consumers relative to the benefits provided. But the cost-effectiveness of an incentive for CCS commercialization will also depend on its ability to avoid subsidizing investment that would have been made even without the incentive.

V.A.2 Public Funds Require Adaptive Resource Management

Policy makers should also plan for CCS incentives under an adaptive resource management structure, which can restructure public investment programming as new information appears about CCS economics and finance. For example, it is very difficult to assess the value of shared technological learning. Existing policy tools such as patents help firms capture some portion of technological learning from private investments. This appropriated knowledge has value to firms and is not a market failure. In contrast, shared technological learning may range from narrow spillovers for a single competitor firm to broad spillovers for the larger market, and that portion constitutes a market failure.

Accurate quantification of the magnitude of these spillovers is challenging and undoubtedly technology-specific. Attempts to measure it using metrics such as progress ratios cannot fully distinguish between efficiency gains driven by shared technology learning and those driven by other factors. In this context, Federal policy should conservatively balance potential subsidies against their costs. These costs include potential economic distortions from taxation and spending, the risk of having subsidies effectively pick technology "winners," opportunity costs of not using funds elsewhere, and the increasing risk of subsidizing "free-rider" investments that would have occurred anyway as CCS commercialization advances.

Federal support targeting CCS-related market failures should leverage considerable non-Federal public and private resources. As the market begins to mature, growing experience with CCS plants operating under varied conditions and configurations will shrink information gaps, thereby weakening the case for continued Federal support. Yet the endpoint for public incentives is not obvious. Policy makers should consider at what point incentives should be terminated, prior to committing to provide them. Moreover, there should be continual re-evaluation of the merits of continuing subsidies as more is learned about the magnitude of any market failures that those incentives are expected to address. Nevertheless, it should be recognized that subsidies, once enacted, are difficult to terminate.

V.B Tailoring Public Funding for Targeted CCS Projects

Creating a long-run price on GHG emissions through a market-based mechanism can internalize the social cost of emissions to the extent that the cap reflects society's judgment of acceptable emission levels. A policy requiring CO_2 abatement is a necessary precondition to the economic relevance of CCS projects at any scale beyond what the market currently supports for EOR and beneficial reuse of CO_2.[100]

For purposes of supporting a limited number of initial CCS projects to address the market failure of knowledge spillovers, the economic gap to viability of those CCS applications must be addressed. Policy makers must acknowledge that such an economic gap would be narrowed under a cap-and-trade program by the allowance price for each tonne of CO_2 emissions avoided (i.e., incentive design for public investment should complement, not duplicate, the market's willingness to pay for mitigation).

A variety of policies can capture shared technological learning in the demonstration and deployment phases of CCS development. Any portfolio of incentives would need to be carefully coordinated to address both the construction and operation of plants using CCS.[101] For example, production-based incentives would improve the project's frequency of operation (and

[100] For example, while Denbury Resources's willingness to pay up to $7 per tonne of CO_2 for EOR assists CCS projects' economic standing, Tenaska's planned Taylorville CCS plant relies significantly on the recently enacted Clean Coal Portfolio Standard in Illinois. See (Bloomberg New Energy Finance, 2010).

[101] If incentives are sufficient to drive construction, but not subsequent operation of the CCS capability, then cost-effective acquisition of knowledge spillovers may suffer.

thus would increase the learning-by-doing that may yield knowledge spillovers), while investment subsidies may be more appropriate when the government has a comparative advantage in raising capital for riskier technology applications (such as demonstration projects).[102]

To address knowledge spillovers from demonstration and initial deployment, policy makers will need to determine how such potential spillovers impair the market's willingness to invest in the face of early CCS project risk and cost. The following sections detail these factors.

Large-scale demonstrations of CO_2 capture technologies are very important for encouraging the successful commercial deployment of CCS (Kuuskraa, 2007; MIT, 2007; National Research Council, 2007; GAO, 2008). While industrial CO_2 separation processes have been commercially available for some time, they have not been deployed at the scale required for large power plant applications. The CO_2 capture capacities for current industrial processes are typically an order of magnitude smaller than the capacity required for a typical power plant.

A concern regarding CO_2 capture technologies is whether they will safely and reliably work when applied to coal-based power generation. Based on previous experience of CO_2 capture technologies in industrial applications, it would appear that these systems should be effective at larger scale in power generation applications. However, until these systems are constructed and successfully demonstrated at full scale, uncertainty over the technology's performance and cost yield a substantial risk premium for early projects.

The International Risk Governance Council recently identified five categories of risk affecting CO_2 capture applied to coal-based power generation. These categories included technical risks; economic and financial risks; health, safety, and environmental risks; legal and regulatory risks; and public acceptance risks (Oak Ridge National Laboratory, 2007; IEA, 2008; International Risk Governance Council, 2009). The latter three categories include "threshold" risk challenges, which are addressed in other sections of this report. Successful resolution of those threshold risks (such as long-term liability management) is necessary but not sufficient to overcome the market failures to first-mover adoption of commercial-scale CCS technology.

Technical risk from the scale-up of currently available CO_2 capture technologies includes unforeseen problems in plant operation that could require design and/or operational reform. In addition, the gas streams being treated with current industrial CO_2 capture processes have different compositions and characteristics than flue gas generated by commercial-scale coal-based power plants that could adversely affect process performance. Only commercial-scale

[102] Production incentives also theoretically improve a project's ability to secure private-sector financing by improving expected gains. However, if investors are risk-averse, then pairing production incentives with investment incentives may be more cost-effective by lowering the cost of capital associated with relatively high-risk projects.

demonstrations on actual flue gas will generate operational data to inform accurate estimates of the cost and performance of these technologies.

Primarily as a result of technical risk, there are also economic and financial risks associated with application of CO_2 capture technologies to coal-based power generation. Acquiring adequate financing for early adoption of CO_2 capture systems could be difficult until there is a positive track record of cost and performance. The risk of cost uncertainty is compounded by uncertain benefits from investing in utility-scale CCS technology in the absence of a price on CO_2 emissions.

Uncertainty over technology cost and performance has a greater impact on investment decisions in the power sector, as projects require large upfront capital for long-term use. To justify a high-risk investment, private sector financing seeks a correspondingly high potential reward. Uncertainty of the actual costs of building and operating CCS may lead utilities and regulatory commissioners to postpone such investments, locking in potentially suboptimal established technologies for decades.

To ensure viability for those commercial-scale demonstrations and early deployments of CCS power projects that are supported by public funds - on the basis of anticipated technological learning - appropriate incentives should bridge the gap between a project's COE and the projected market electricity price. COE projections for these projects are above-expected electricity prices in the near term because currently available CCS technologies are relatively expensive and energy-intensive, due to the energy required to capture, compress, transport, and store CO_2 into geologic formations (Herzog et al., 2009).

Because CCS projects require relatively high capital cost outlays, they are highly sensitive to changes in the cost of obtaining capital, which is a function of the project's perceived risk by investors. Therefore, narrowing the gap between these projects' COE values and expected market electricity prices can be achieved both by reducing upfront project cost, and by reducing the risk to financiers of providing capital for the projects in addition to establishing a price on carbon.

To address the market failure of knowledge spillovers, the Federal government currently pursues two complementary pathways for public funding of targeted CCS applications. The first pathway, referred to as "technology push," includes direct Federal expenditures and authorized ratepayer funding for RD&D of CCS technologies. The second pathway, referred to as "market pull," offers a variety of publicly funded financial and economic incentives structured to encourage private investment in advancement and deployment of CCS technology. The advantages and considerations of the tools within these investment pathways are discussed in the following two sections.

V.C Technology-Push Drivers for CCS

CCS technologies currently exist but are not likely to be widely deployed at coal-fired power plants and other large industrial point sources without additional knowledge generated by research, development, and demonstration activities. The current focus of RD&D activities is thus two-fold:

- Demonstrate the operation of current CCS technologies integrated at an appropriate scale to prove safe and reliable capture and storage.
- Develop improved CO_2 capture component technologies and advanced power generation technologies to significantly reduce the cost of CCS, to facilitate widespread cost-effective deployment after 2020.

DOE's Office of Fossil Energy partners with industry and others to manage and perform RD&D activities on low-carbon fossil energy technologies. The thrust of these activities, implemented by DOE's National Energy Technology Laboratory (NETL), is the efficient and cost-effective reduction and removal of CO_2 from power plant fuel and flue gas streams and sequestration in geologic formations. DOE's current RD&D program is structured to leverage the strengths of its public and private sector partners to conduct applied research, proof-of-concept technology evaluation, and pilot-scale testing leading to large-scale demonstrations. DOE's RD&D efforts support the goal of widespread, cost-effective deployment of CCS technologies by addressing the knowledge spillover market failure that impedes private sector investment in low-carbon technologies. DOE's efforts are guided by the Secretary of Energy's goal to support RD&D so that widespread cost-effective deployment of CCS can begin in eight to ten years (Chu, 2009). Currently funded DOE activities[103] are expected to have a significant impact, as described below and further detailed in Appendix E. In addition, a detailed description of these RD&D activities can be found in the President's FY2011 Congressional Budget Request for the Office of Fossil Energy.

V.C.1 Demonstration of Current CCS Technologies

The integration of CO_2 capture, transportation, and permanent sequestration at commercial-scale, coal-fired power generating facilities has not yet been demonstrated. From a technical perspective, the ability to capture CO_2, compress it for pipeline delivery, and sustain delivery at pressures adequate to ensure dependable injection and reservoir permeability must be confirmed. DOE is currently pursuing multiple demonstration projects, using $3.4 billion of available budgetary resources from American Recovery and Reinvestment Act in addition to prior year appropriations. Successful implementation of these projects will meet the President's

[103] DOE appropriations for CCS applications include about $400 million annually for RD&D in fiscal years 2009, 2010, and 2011 (requested), as well as $3.4 billion of ARRA funding for DOE-sponsored demonstration projects for CCS projects at industrial facilities and power plants.

goal of five to ten commercial scale demonstrations online by 2016, but will require carefully structured financial plans to manage the large costs associated with these projects.

Up to 10 integrated CCS demonstration plants in the power and industrial sectors are expected to begin operation in the United States under DOE's CCPI, FutureGen (funded by the ARRA and prior year funds), and ICCS solicitation (funded by ARRA). These demonstrations will integrate state-of-the-art CCS technologies with commercial coal and industrial plants to show that they can be permitted and reliably operated. New power plant applications will focus on bringing together IGCC technology with pre-combustion CO_2 capture, transport, and geologic sequestration. Power plant retrofit and industrial applications will demonstrate integrated post-combustion capture. Table V-2 summarizes the planned DOE CCS demonstration projects. These projects, in tandem with other projects supported by Federal loan guarantees, tax incentives, and State-level drivers, cover a large group of potential CCS options. However, ongoing reviews of early projects may identify any remaining gaps in the demonstration of capture technologies and classes of storage reservoirs. Early low-carbon energy projects, including these 10 CCS demonstration projects, may face economic challenges, such as the absence of a carbon price. To the extent appropriate, additional actions may be required to support these projects, consistent with the approach of addressing market failures in a targeted manner.

Table V-2: Planned DOE CCS Demonstration Projects

Performer	Location	Capture Technology	Capture Rate (tonnes per year)	Target Formation	Start Date
Pre-Combustion Capture					
Summit Texas Clean Energy	Odessa, TX	Selexol™	2,700,000	EOR	2014
Southern Company	Kemper County, MS	Selexol™	1,800,000	EOR	2014
Hydrogen Energy California	Kern County, CA	Rectisol®	1,800,000	EOR/Saline	2016
Post-Combustion Capture					
Basin Electric	Beulah, ND	Amine	450,000-1,360,000	EOR/Saline	2014
NRG Energy	Thompsons, TX	Amine	400,000	EOR	2015

American Electric Power	New Haven, WV	Chilled Ammonia	1,500,000	Saline	2015
Oxy-Combustion					
FutureGen	Meredosia and Mattoon, IL	Oxy-Combustion	1,000,000	Saline	2015
Industrial					
Leucadia Energy Lake Charles	Lake Charles, LA	Rectisol®	4,000,000	EOR	2014
Air Products	Port Arthur, TX	Amine	900,000	EOR	2013
Archer Daniels Midland	Decatur, IL	Amine	900,000	Saline	2014

Congress is considering another means of supporting large-scale integrated CCS demonstrations projects in the form of an additional wires charge to the sale of fossil-based electricity. The fees would be weighted based on carbon content of the fuel: coal-based generation would be assessed a charge higher than oil-based, which is in turn higher than natural-gas-based generation. Existing legislative proposals would make between $1 billion and $2 billion available annually to support CCS demonstrations for up to 10 years.

V.C.2 RD&D of CCS Technologies

In the context of the DOE Fossil Energy RD&D program, state-of-the-art ("1st generation") CCS technology is described in Section III. As part of its R&D programs, DOE is pursuing advanced ("2nd generation") technologies that could significantly reduce the cost and energy penalties associated with 1st generation CCS technologies. For a full description of 2nd generation technologies, see Appendix E. Current DOE efforts include advanced computational modeling, simulation, and analysis to accelerate the development of 2nd generation CCS technologies. This includes the development of science-based models of fossil fuel conversion processes; advanced high-temperature materials; and robust sensors to improve system performance.

RD&D and learning-by-doing could transform CCS from a technology only affordable to industrialized nations to a cost-effective GHG mitigation option with a global impact. Long-term RD&D could also support biomass co-firing with CCS, which, if the biomass is sustainably harvested, could result in "net negative" GHG emissions. DOE estimates that for new plants, 2nd generation CO_2 capture technologies combined with advanced power generation technologies could limit the increase in COE at the plant gate to 30 percent compared with a modern supercritical PC plant without CCS. For current 1st generation CCS plants, DOE estimates this increase to be 60–80 percent. For CCS retrofits, DOE estimates that the increase in cost could be reduced by two-thirds with 2nd generation technology (NETL, 2009b). For example:

- Advanced gasification-based technology could achieve high capacity factors and include membrane technology for O_2 supply and H_2/CO_2 separation, warm gas cleanup, and either high-efficiency H_2 turbines or pressurized solid oxide fuels cells to generate electricity.
- New PC plants could be designed for more efficient operation using advanced high pressure-high temperature power cycles.
- New and retrofit power plants and industrial facilities could use advanced 2nd generation CO_2 capture technologies including solvents, solid sorbents, and membranes for post-combustion capture.
- Oxy-combustion power plants could use membranes for O_2 supply and other innovations to improve plant efficiency. Better understanding of flame characteristics, burner and coal-feed design, and analyses of the interactions between products of combustion and boiler materials could improve the development of low-cost and efficient oxy-combustion power plant systems.

CO_2 sequestration technology will continue to evolve, allowing safe and permanent sequestration in more challenging formations, and enabling the wider deployment of CCS. Large-scale geologic CO_2 sequestration tests are being conducted across the country under the Regional Carbon Sequestration Partnership Program that complement RD&D aimed at improving the ability to predict and track the flow of CO_2 injected into geologic formations, including an improved understanding of geologic trapping mechanisms that can reduce CO_2 sequestration concerns, and establish best practices that facilitate permitting.

One option for improving the cost-effectiveness of CCS deployment is to accelerate the availability of 2nd generation CCS technologies, and DOE is currently working to utilize Recovery Act funding for this purpose. This accelerated program will focus on developing more efficient, lower capital cost CCS technologies, and help to meet the President's goal to enable widespread, cost-effective deployment of CCS within ten years.

V.C.3 International Collaboration

Widescale deployment of fully integrated, efficient, cost-effective CCS systems depends strongly on RD&D efforts to advance CCS technologies. U.S. government collaboration with other countries on fossil energy technologies is motivated by the premise that joint technology RD&D can help to improve energy security, address climate change challenges, and position U.S. businesses as global technology leaders. Mutually beneficial RD&D with foreign partners and promotion of U.S. clean energy technologies in foreign markets are central to the U.S. government's desire to address the environmental impacts of producing and using fossil fuels. International collaboration offers several potential advantages: First, the technology development cycle can be shortened via cooperation with experts working on creative concepts in foreign RD&D organizations that have invested in unique facilities; second, international collaboration can lower the cost to U.S. taxpayers of achieving programmatic and national objectives via meaningful, coordinated, cost-shared RD&D; and third, access to world-class foreign researchers, who often look at the problems associated with taking a technology from the lab to the marketplace through different "lenses," can help to create more practical, globally acceptable technology solutions to the problems associated with producing and using fossil fuels.

Most CCS technology RD&D is being sponsored by and occurring in the United States and other developed countries. Collaboration with other developed countries may help to prove the viability of CCS as a long-term climate change mitigation option by speeding global acceptance and commercialization and by leveraging resources and sharing of results. However, as discussed in Section II, emerging economies will also need to widely deploy low- and zero-carbon electricity generation technologies, such as CCS, to achieve global climate change mitigation goals. The United States should continue its leadership role engaging large, coal-dependent emerging economies with rapidly expanding power sectors to avoid locking in inefficient, high GHG emission power generation assets for decades. Failure to do so may make subsequent CCS deployment more difficult and increase the cost of meeting global GHG reduction targets.

Currently 10 countries (China, United States, India, Russia, Japan, South Africa, Germany, Republic of Korea, Australia, and Poland—ordered by annual emissions) account for 83 percent of the global CO_2 emissions from coal use. Despite efforts being undertaken in various fora, data on the potential geologic CO_2 sequestration capacity for these countries are not available on a consistent basis. However, an assessment of available data indicates that sufficient sequestration capacity is likely available where needed relative to these countries' current coal-based emissions. Most of these countries likely have hundreds to thousands of years of potential sequestration capacity, based on current emissions from coal combustion in all sectors (Appendix N).

The recently established Global Carbon Capture and Storage Institute has cataloged and analyzed potential CCS projects worldwide (Global CCS Institute, 2010). A total of 80 large-scale integrated projects in 17 countries (Algeria, Australia, Canada, China, Czech Republic, Finland, France, Germany, Italy, Republic of Korea, Netherlands, Norway, Poland, Spain, United Arab Emirates, United Kingdom, and the United States) were identified and classified according to their development status and progress toward key decision points for project design, definition, cost estimation, execution planning, and risk analysis. Each of these projects was assessed against criteria developed by the IEA to ascertain whether they would meet the commitment made by G8 leaders in 2008 at their Hokkaido Toyako Summit to launch 20 large-scale CCS demonstration projects by 2010, with a view to beginning broad deployment of CCS by 2020. Thirty-one of the 80 large-scale integrated CCS projects that were identified and assessed by GCCSI are located in the United States. The GCCSI found "…that most projects require significant work to narrow the gap to be considered launched at this time under the G8 criteria" They also indicated that while "the growing pipeline of projects is a positive development and is suggestive of a wider deployment of CCS by 2020," that "broader scale deployment in this all encompassing sense is still faced with significant challenge." Global cooperation on these projects is important for advancing CCS technology and gaining public acceptance.

In addition to enhancing RD&D, international collaboration may help to address other barriers to deployment that will advance domestic objectives. Ensuring that a means is available for U.S. interests to participate in CCS projects in other countries can allow the United States to benefit from both the knowledge created in these projects and from potential export opportunities. In some instances, it might also allow U.S. companies to acquire international offset credits for use in compliance with domestic legislation.

The United States is involved in many bilateral and multilateral cooperative agreements and initiatives in which CCS is either the focus or a key element of the cooperation. These cost-shared activities span cooperation with both developed and developing countries focusing on a wide range of objectives (RD&D, capacity building, regulatory development, finance, market assessments, engineering analyses, and information exchange) that help advance CCS technology development and acceptance in the United States. The Carbon Sequestration Leadership Forum (CSLF) is an example of multilateral cooperation focused on the development of improved cost-effective technologies for the separation and capture of CO_2 and its transport and long-term, safe geologic sequestration. The mission of the CSLF is to facilitate the development and deployment of such technologies via collaborative efforts that address key technical, economic, and environmental obstacles. Other multilateral efforts are being conducted through the IEA, the Asia-Pacific Partnership for Clean Development and Climate, the Asia Pacific Economic Cooperation, the Global Carbon Capture and Storage Institute and the Major Economies Forum's Global Partnership. Examples of current bilateral cooperation include RD&D and demonstration activities being undertaken with Australia, Brazil, Canada, China, Japan, Republic of Korea, and Norway. In addition, more than 25 organizations from some 15 countries participate in DOE RCSP efforts.

Coordination of efforts being undertaken through bilateral and multilateral cooperation on CCS technology RD&D, policy development, and public engagement is critical to ensure maximum effectiveness, both from the standpoint of making wise investments of taxpayer dollars and to rapidly advance the most promising technologies through the development cycle into early deployment and wide acceptance. The Office of Clean Energy Collaboration within the Office of Fossil Energy leads coordination of DOE's CCS cooperation with other countries and within the Department, engaging with the State Department as appropriate. Periodic reviews of ongoing and planned activities are conducted, usually with input from the private sector. Bilateral engagement on CCS is coordinated within DOE through strategic energy policy dialogues, with participation by the State Department, to ensure consistency with the Administration's broader international priorities and climate and energy goals. Coordination of efforts being undertaken through multilateral cooperation is more difficult given the number of countries in these organizations, different funding cycles, varying levels of involvement by key countries, and at times different political objectives for participation. The State Department has a leading role in coordination of multilateral RD&D cooperation along with DOE's Office of Policy & International Affairs.

Information on key design parameters from CCS projects being implemented by leading RD&D organizations and private-sector firms in other countries, along with lessons learned on their operational issues (especially from projects with similar geologic formations), will help the United States in proving the long-term safe and effective geologic sequestration of CO_2. The United States is currently participating in 10 large-scale CCS projects in other countries to gain additional information sooner on key technologies and issues (Table N-2 in Appendix N). U.S. scientists are intimately involved in field experiments for site characterization and well monitoring, performing reservoir simulation modeling, and developing and testing an array of monitoring, verification and accounting techniques and technologies—all of which will yield information that will help to overcome technological barriers to CCS deployment domestically.

V.D Market-Pull Incentives for CCS

V.D.1 Loan Guarantees

Government loan guarantees can help promising, early-stage commercial technologies penetrate markets in which providers of capital are either unable or unwilling to provide financing without public assistance. Such reluctance may reflect substantial capital requirements, the complexity and unproven nature of the technologies, regulatory uncertainty concerning CO_2 emissions, and/or the impaired functioning of markets that would normally supply capital, particularly debt.

The capital structure of projects receiving loan guarantees generally includes a significant amount of debt. By statute, candidate projects are required to have a reasonable prospect that project sponsors will repay the underlying loans. For projects receiving a DOE loan guarantee, debt can fund up to 80 percent of project costs, although a candidate project is generally more attractive the greater the proportion of equity at stake. Equity contributed by the project sponsors would fund the remaining costs. In any financing in which a large amount of debt is used to finance the project, it is important that sponsors maintain substantial equity capital at risk during the life of the debt. This creates a compelling incentive for the sponsor not simply to develop a project, but to work toward its long-term success so that the debt will be repaid in the manner in which the underlying loan anticipates. DOE's Loan Guarantee Program (LGP) for fossil fuel energy projects currently is evaluating CCS projects that gasify coal or petroleum coke and produce a range of products from power and natural gas to transportation fuel and chemical manufacturing feedstock such as ammonia and methanol.

The USDA's Rural Utilities Service (RUS) makes direct loans and loan guarantees to electric utilities, and is already supporting at least one CCS project. All plant improvement projects are reviewed based on need to meet either current or pending regulations, the project's technical feasibility, net present worth economic analysis, and the borrower's financial ratings. Up to 100 percent financing of CCS projects could potentially be provided based on the review of these requirements.

A CCS project can support a loan (and a loan guarantee) only if it creates a consistent cash flow stream with which to service the debt. For this reason, pre-commercial projects with uncertain performance projections are typically better candidates for grant funding than for loan guarantees. Moreover, the current field of candidate projects for loan guarantees is relatively limited by the inability of CCS projects to rely on cash flow from CO_2 abatement prior to enactment of a policy to create a carbon market. Establishment of a domestic carbon price could markedly improve the financial profile of CCS projects. The foundation for a candidate project's creditworthiness requires, among other things, sound supply agreements, product sales agreements, reliable operations, and a high level of maintenance of the production facility. Therefore, projects under consideration to date rely on low-risk capture and sequestration methods based on commercial technology, such as pre-combustion capture techniques with beneficial reuse of the CO_2 produced.

Prospective financial success, sponsor expertise, and each project's contribution towards reducing, avoiding, or sequestering greenhouse gas emissions should govern the admission and vetting of investments in a loan guarantee program. Loan guarantees should be structured to complement, not displace, the private sector's efforts to finance large capital projects in power generation, oil and gas, petrochemicals, infrastructure, and public works.

The process of issuing loan guarantees is contingent on the ability to underwrite the risks in CCS projects, a complex task in the absence of clear regulatory and legal frameworks. Section VII lays out potential responses to CCS legal and regulatory issues in greater detail.

V.D.2 Tax Treatment

The Internal Revenue Code already contains a number of incentives to support CCS technology development and deployment. Section 41 and Section 174 include a special tax credit for qualifying research expenditures and a deduction for research expenditures incurred.

The research and experimentation (R&E) tax credit is 20 percent of qualified research expenses above a base amount determined by the taxpayer's historical research intensity. Taxpayers can elect the alternative simplified research credit (ASC), which is equal to 14 percent of qualified research expenses that exceed a base amount equal to 50 percent of the average qualified research expenses for the three preceding taxable years. The R&E tax credit also provides a credit for 20 percent of basic research payments above a base amount, and for all eligible payments to an energy research consortium for energy research. The R&E credit expires for amounts paid or incurred after December 31, 2009. However, the Administration's FY 2011 Budget has proposed to make this tax credit permanent.

Taxpayers currently may elect to deduct the amount of certain research or experimental expenditures paid or incurred in connection with a trade or business, notwithstanding the general rule that business expenses to develop or create an asset that has a useful life extending beyond the current year must be capitalized. However, these deductions are reduced by the amount of the taxpayer's research tax credit determined for the taxable year. Taxpayers may alternatively elect to claim a reduced R&E tax credit amount in lieu of reducing deductions otherwise allowed.

The present tax credits for R&E generally do not favor one particular technology over another because credits are available for all qualifying scientific research expenditures. The government is not attempting to "pick winners"—the firm decides what R&E investments to undertake. Research expenditures on clean energy technologies and CCS are potentially eligible for the present credits provided they meet certain eligibility criteria.[104]

An investment tax credit under section 48A is available for power generation projects that use IGCC or other advanced coal-based electricity generation technologies. As originally enacted in 2005, the credit amount is 20 percent for investments in qualifying IGCC projects and 15 percent for investments in qualifying projects that use other advanced coal-based electricity generation technologies. The Secretary of the Treasury may allocate $800 million of credits to IGCC projects and $500 million to projects using other advanced coal-based electric generation technologies. Under the 2008 amendments to this provision, the credit rate is increased to 30 percent for new IGCC and other advanced coal projects and the Secretary is permitted to allocate an additional $1.25 billion of credits to qualifying projects. The 2008 amendments also provide that qualifying projects must include equipment that separates and sequesters 65 percent of the project's total CO_2 emissions.

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[104] Qualified research is research that is undertaken for the purpose of discovering information that is technological in nature, the application of which is intended to be useful in the development of a new or improved business component of the taxpayer, and substantially all of the activities of which constitute elements of a process of experimentation for functional aspects, performance, reliability, or quality of a business component.

Under section 48B, as originally enacted in 2005, a tax credit of 20 percent was available for investments in certain qualifying gasification projects. The Secretary may not allocate more than $350 million in credits. Under the 2008 amendments to the provision, the gasification project credit rate is increased to 30 percent and the Secretary is authorized to allocate an additional $250 million of credits to qualified projects that separate and sequester at least 75 percent of total CO_2 emissions.[105]

Under section 169, a taxpayer may elect to recover over a period of 60 months the cost of any certified pollution control facility that is used in connection with a plant or other property that was in operation before January 1, 1976. An air pollution control facility, if used in connection with electric generation property that is primarily coal-fired and was placed in operation after December 31, 1975, may qualify for an amortization period of 84 months.[106]

Under section 45Q, a credit of $10 per tonne is available for qualified CO_2 that is captured at a qualified facility, used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and disposed of in secure geological sequestration. In addition, a credit of $20 per tonne is available for qualified CO_2 captured by a taxpayer at a qualified facility and disposed in secure geological sequestration without being used as a tertiary injectant. The credit sunsets at the end of the calendar year in which the Treasury Secretary certifies, in consultation with the Administrator of the Environmental Protection Agency, that 75 million tonnes of qualified CO_2 have been captured and sequestered. As a point of reference, a 1,000 MW CCS power plant that captures 90 percent of its CO_2 emissions and has a utilization rate of 80 percent would capture a cumulative amount of about 75 million tonnes over an 11-year period.

In general, the value of tax subsidies may not be equal among firms because some firms may not have sufficient tax liability against which to claim the credit. Further, non-taxable entities, such as governmental bodies and cooperative electric companies, cannot take direct advantage of investment or sequestration tax credits, although they could benefit from tax credit bonds.

Firms without enough tax liability to take advantage of the credits will have less incentive to invest in tax-favored investments than those firms that can take immediate advantage of the credits. Firms generally may carry unused credits back one year and use them to offset tax liability that year or forward to a future period when they have enough tax liability to use the

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[105] As of June 14, 2010, all $350 million 48B credits and $908.5 million 48A credits authorized under sections 48A and 48B as originally enacted have been allocated. All $250 million 48B credits and approximately $1 billion of the 48A credits authorized under the 2008 amendments have been allocated.

[106] Thus, special amortization may be allowed for certain qualified CCS property. The CO_2 capture equipment must be certified by EPA that its function is the abatement or control of air pollution and that it is in compliance with applicable Federal regulations. The equipment cannot alter the nature of the production process and cannot significantly increase the output or capacity, extend the useful life, or reduce the total operating costs of the production plant.

credits, but credits that are carried forward have a lower present value than credits that can be claimed in the year they are earned.[107] Carlson and Metcalf (2008) found that between 2000 and 2005, the ability of corporations to take energy-related tax credits was significantly curtailed by limitations in the regular tax on the use of general business credits. For example, for most years, between half and two-thirds of the renewable electricity production credit could be taken in the current year. In 2003 and 2004, however, only one-quarter of the credits could be taken immediately. In addition, the corporate alternative minimum tax (AMT) can reduce the value of preferential depreciation rates for energy-related capital investment and energy-related tax credits by deferring the time at which they may be claimed. Firms can form a partnership with other firms that have sufficient taxable income to take advantage of energy-related tax credits. In this context, the latter firms are referred to as "tax equity investors." However, the costs associated with the financial arrangements necessary for the partnership also reduce the value of the tax credits. As was seen in the recent financial crisis, a disruption in the tax equity markets may significantly reduce the ability of firms to take advantage of tax credits.

An additional consideration is whether a proposed tax subsidy would yield additional investment in qualifying facilities, or instead simply subsidize activity that would have taken place anyway. For example, at least some recipients of Federal renewable tax credits likely would have deployed renewable energy sources in response to State renewable portfolio standards; the tax credits were not necessarily a motivating factor. The R&E credit attempts to focus the incentive on research that would not have been taken in the absence of the credit by requiring that research exceed a base amount related to the firm's historical research activity. However, the base amount may not accurately measure the amount of research that would have been taken anyway, so some R&E credits likely are claimed for expenditures that would have taken place in the absence of incentives. Further, the energy research credit does not have a base amount (i.e., it is available for the first dollar of qualified energy research expenditures) and thus likely subsidizes some research that would have been undertaken anyway.

In cases where the incentive subsidizes an activity that would have been undertaken even in the absence of a subsidy, some of the reductions in Federal tax receipts offer no additional environmental or technological benefit. Insofar as CCS would be the economic response of choice by the private sector to other policies (such as a price on carbon) in the future, tax credits would divert revenue but fail to deliver additional benefits.

Finally, it is important to remember that in order to be deficit-neutral, tax credits must be paid for with higher distortionary taxes elsewhere in the economy. Thus, the cost of a tax credit to

[107] Generally, the general business credit may not exceed net income tax less the greater of the taxpayer's tentative minimum tax liability or 25 percent of net regular tax liability above $25,000. Unused general business credits may be carried back one year and forward twenty years.

the public budget is typically greater than the revenue foregone from the affected tax, insofar as the shift in the tax burden yields suboptimal conditions in the national economy.

V.D.3 Greenhouse Gas "Bonus" Allowance Allocation

Recent legislative proposals for GHG cap-and-trade systems have reserved a share of emission allowances for free allocation to CCS applications. For example, the American Power Act of 2010 discussion draft (APA) reserves about 6.3 percent of total allowances from vintage years 2017–2034 for a "bonus allowance" program for CCS installations. Qualifying industrial facilities and electricity generators, including retrofits, receive the incentive for the first 10 years of their CCS operation. However, industrial facilities are limited to receive collectively no more than 15 percent of the total incentive awarded. Electricity generators must burn at least 50 percent coal or petroleum coke fuel to qualify, and coal-to-liquids facilities cannot qualify for the incentive.

The APA discussion draft structures the bonus allowance incentive in three project tranches. Projects in the first tranche of 10 gigawatts (GW) of CCS receive between $50 and $96 per tonne of CO_2 sequestered (plus $10 per tonne if online by 2017), with the precise value determined by a project's rate of CO_2 capture and sequestration (between 50 and 90 percent). Projects in the second tranche of 10 GW receive between $50 and $85 per tonne based on a similar scale of percentage of emissions sequestered. Developers of projects in the third tranche of up to 50 additional GW of CCS would participate in reverse auctions to establish the disbursement price per tonne of CO_2 sequestered.

The total value of this incentive is a function of the total number of allowances reserved and their market prices. Under the carbon prices modeled in EPA's recent analysis of the APA discussion draft, the total value of the CCS bonus allowance incentive is about $166 billion in 2005 dollars.[108]

Under this incentive structure, recipients are paid a particular sum (fixed in statute or determined in a reverse auction, based on the tranche) for each tonne of CO_2 sequestered, but the payment is denominated in allowances. A CCS project being awarded $90 per tonne of sequestered CO_2 would receive nine allowances (for each tonne sequestered) if the carbon price is $10, or only six allowances if the carbon price is $15.[109] The monetary value of the total incentive disbursement is the same between those scenarios, but more allowances are required for the award when the carbon price is lower. The total value available via this incentive is capped by a fixed number of allowances (not by total funding disbursed). Therefore, a lower carbon price path reduces the total deployment potential using this incentive, while a higher carbon price path would increase the amount of sequestration supported by bonus allowances.

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[108] Environmental Protection Agency, June 2010 Analysis of the American Power Act, http://epa.gov/climatechange/economics/economicanalyses.html.

[109] Carbon pricing is per tonne of CO_2 (the same measure for each greenhouse gas allowance).

The differences in the incentive structure between each project tranche are significant. In the first two tranches, the incentive value is fixed on a per-tonne of CO_2 sequestered basis. Such a sequestration incentive should target the economic gap between the cost of sequestration and what the private market is willing to pay. The latter factor is directly reflected by the carbon price under a cap-and-trade system, which is the market value of each tonne of CO_2 abated. Thus, the economic gap to sequestration will shrink or grow as the carbon price rises or falls.

A fixed per-tonne incentive fails to accommodate both for the market's willingness to pay for CCS and for the ultimate cost of CCS, which may lead the incentive to fall short of or exceed the economic gap for qualifying CCS deployment. This potential mismatch of the fixed per-tonne bonus value to the CCS economic gap impairs this incentive's cost-effectiveness. If the fixed value is set too low, then otherwise-qualifying CCS projects will not be economically viable and at least some of the incentive will go unclaimed. If it is set too high, then the limited value of the total incentive is depleted faster for fewer results and the public investment will have displaced at least some willing private investment.

The third tranche replaces the fixed per-tonne values with a system for conducting reverse auctions for qualifying projects. The concept of a reverse auction positions the government as a "sequestration buyer" and multiple candidate CCS projects as "sequestration sellers." If the reserve auction process is structured to screen out fraudulent or unqualified bidders, the resulting competition between candidate projects greatly increases the cost-effectiveness of the allocated CCS bonus allowances. The auction process allows participants in the marketplace to make informed bids based on knowledge of CCS costs and the market value of CO_2 abatement (e.g., the allowance price); these variables are unpredictable in advance and sometimes unknowable to policy-makers.[110] Reverse auction bidding would calibrate the incentive's per-tonne value to match the economic gap for qualifying CCS. In addition, the competition between projects should yield the most sequestration possible for the value of the total bonus allocation awarded in the second tranche. Like other auction procedures, a reverse auction approach for CCS bonus allowances would need to establish safeguards against failure of participants to deliver on their bids and against potential collusion between participants.[111]

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[110] In expert Congressional testimony, one CCS vendor observed that "climate legislation proposals, which arbitrarily set CCS incentive prices, would result in less cost-effective CCS technologies being subsidized, while plant owners/developers and regulators gain little or no information on what real CCS costs are" (Alix, 2009).

[111] A recent report proposes several options for vetting reverse auction bids: "For instance, the [qualifying project's development] plan could demonstrate that the bidder is able, within 12 months of the bid being accepted, to finalize EOR or transport sequestration agreements, obtain final air permits, secure final financial commitments, and break ground on the project. The development plan could also demonstrate the ability of the bidder to achieve commercial operation within four years of the bid being accepted. These requirements will help ensure that auction participants are serious bidders capable of building and operating the proposed projects in a timely and effective manner" (Clean Air Task Force, 2010).

The magnitude of bonus allowances does not appear calibrated to address specific market failures. Public investment on the order of $166 billion, if structured properly to be matched to economic gaps as discussed above, may drive a substantial amount of geologic sequestration of CO_2. However, policy-makers cannot know with certainty in advance of a cap-and-trade system if such a level of sequestration would be the efficient, cost-minimizing reaction of the marketplace to the carbon price path established by the cap.

If bonus allowances fund CCS deployment beyond the demonstration and early deployment projects relevant to the market failure of knowledge spillovers, then this incentive will have distorted the economic reaction to the carbon price signal by substituting high-cost for low-cost emission reductions. Simultaneously, such potential over-subsidization of CCS deployment would artificially lower electricity prices, which muffles the carbon price signal to consumers and reduces the incentive for efficiency in electricity consumption (among the lowest-cost potential CO_2 emissions mitigation options).[112]

[112] McKinsey & Company (2007).

VI. Options for Enhancing the Legal/Regulatory Framework

A key consideration for both near- and long-term deployment of CCS is whether the existing framework—with proposed modifications—can adequately and effectively govern CCS. The Task Force evaluated select current environmental, natural resources, and other laws potentially relevant to geologic sequestration of CO_2 as discussed in Section IV.B.1 and Appendix F of the report and concluded that the current statutory framework can be used to regulate CCS projects.

Some regulatory actions will be necessary in the near term, to help meet the goal of bringing five to ten commercial demonstration projects online by 2016. As discussed above in Section IV.B.1, new requirements under SDWA, expected to be finalized in late 2010, will establish a new well class for geologic sequestration under the SDWA UIC Program. The new GHG reporting provisions for geologic sequestration facilities under the CAA, also expected in late 2010, will ensure that CO_2 emissions to the atmosphere from capture and sequestration are monitored and reported in both the onshore and offshore environments. Clarification of the regulatory status of CO_2 and/or CO_2 injectate under existing statutes, particularly RCRA, may also be needed, as well as further development of risk evaluation tools to support regulatory development and permitting.

In the longer term, as discussed in Section IV.B, additional actions may be needed to facilitate widespread, cost-effective deployment of CCS within 10 years. Because current environmental laws and programs were not designed with CCS in mind, a "comprehensive" framework may be needed to protect human health and natural resources, while providing a simple, straightforward regulatory system to oversee CCS and speed deployment of these technologies (RFF, 2007; CCS Regulatory Project, 2008; Harvard Kennedy School, 2009). However, particularly for near-term deployment, it may be appropriate to build upon the existing framework (with some modifications) (IEA, 2008; CCS Regulatory Project, 2009b; Harvard Kennedy School, 2009). The Task Force has assessed the existing regulatory framework with respect to its ability to meet key regulatory goals outlined below.

To facilitate widespread, cost-effective deployment of CCS within 10 years, a future regulatory framework could be designed to balance multiple goals: reducing CO_2 emissions; increasing energy security; and protecting human health, the environment, and our resources. With this in mind, the Task Force has identified two paths for moving forward for long-term deployment of CCS:

Option 1: Build Upon Existing Authorities that Regulate CCS Projects. Current statutes and programs—including SDWA, CAA, RCRA, CERCLA, FLPMA, MPRSA, OCSLA, HLPA and others—could be modified as needed to ensure safe and efficient deployment. Permitting and reporting processes could be streamlined, where appropriate, exemptions could be considered for early projects to accelerate deployment and learning by doing, and regulatory certainty could be enhanced.

Option 2: Create a New Statutory Framework for CCS. A new statutory framework could be developed to include all regulatory considerations and mechanisms under one program. This program would be designed to address all stages of CCS (from the point of capture through long-term stewardship), articulate all potential liabilities, and address all goals of a comprehensive framework. It would establish clear requirements for how geologic sequestration sites could receive a fungible emissions "credit," harmonizing provisions with future climate regulations.

Under either of these options, it would be important to clearly articulate the roles and responsibilities of Federal and State agencies onshore and offshore. Federal involvement could provide consistency in how sites are selected and managed and help address the entire range of potential environmental and legal issues, particularly if long-term stewardship of sites will be assumed or shared by Federal agencies. States are likely to be responsible for most of the permitting and oversight of geologic sequestration sites on private lands; thus coordination and clear delineation of roles will be needed to clarify regulatory authorities and processes.

Creation of a "comprehensive" regulatory framework could address concerns that additional clarity with respect to the existing framework may be needed to facilitate widespread cost-effective deployment. Through a review of the literature, consultation with experts, and interagency dialogue, the Task Force identified eight key goals of a regulatory framework for geologic sequestration of CO_2. The goals are discussed in more detail below:

A comprehensive framework would:

- Be tailored to ensure the integrity of the emissions reductions associated with CO_2 sequestration;
- Address the full range of potential impacts to human health and the environment, including environmental justice;
- Include clear standards, regulatory approaches, and legal or financial mechanisms that might be needed throughout the life of the CO_2 sequestration project, from site selection and operation to long-term stewardship;
- Promote national consistency, yet address existing differences in authorities between the onshore (Private vs. Federal) and offshore (State vs. Federal), and clearly articulate the role of States;
- Include strong compliance assurance and enforcement mechanisms;
- Create flexibility to account for site variability and be adaptive to accommodate learning;

- Build knowledge and public confidence by making information available and creating opportunities for public engagement; and
- Be designed to meet international obligations as appropriate.

Goal 1: Tailor for CO_2 sequestration as a climate change mitigation approach. Given that the purpose of CCS is to address climate change, it will be paramount to ensure that projects reduce CO_2 emissions, and that regulations and programs are designed to consider linking CCS with a future climate regime (RFF, 2007; CCS Regulatory Project, 2009b). EPA has proposed new Federal requirements under the SDWA for the underground injection of CO_2 for the purpose of geologic sequestration, which will create a new class of well under EPA's SDWA UIC Program. This program was designed to protect USDWs, but has limitations with respect to addressing other aspects of CCS, such as GHG mitigation and long-term stewardship of geologic sequestration sites (beyond the post-injection site care period) (CCS Regulatory Project, 2008; Harvard Kennedy School, 2009). While SDWA UIC Program permitting does not directly address air emissions, EPA has proposed methodologies and approaches for monitoring and verification of CO_2 injected and stored as discussed above. In conjunction with data collected under other subparts of EPA's Greenhouse Gas Reporting Program, the data collected under this proposal on the amount of CO_2 injected and geologically stored in the United States would allow EPA and others to track the amount, growth, and efficacy of geologic sequestration over time and to evaluate relevant policy options related to this climate change mitigation strategy.

Goal 2: Address the full range of potential impacts to human health and the environment, including environmental justice. The SDWA UIC statute is focused on protection of USDWs from endangerment, and public health as it relates to endangerment of USDWs; it does not provide authority to address other human health and ecosystem impacts. Proposed UIC Class VI requirements for geologic sequestration wells seek to permanently contain CO_2 by addressing leakage pathways and requiring comprehensive monitoring plans to track movement of CO_2 plumes. These requirements may indirectly protect against some impacts other than those associated with USDWs. However, as discussed in Section III.C improperly operated CO_2 injection activities could conceivably result in release of CO_2 to the atmosphere from underground locations far afield from USDWs. Such releases may have a range of effects on human health and exposed terrestrial and aquatic ecosystems. Other Federal government authority to address human health and environmental impacts exists under various statutes, such as CAA, RCRA, CERCLA, and the Emergency Planning and Community Right-to-Know Act (EPCRA). However, because these authorities differ in scope and coverage, significant efforts by implementing agencies would be needed in order to address all possible impacts from CCS, appropriately balance environmental and safety objectives, reduce redundancy, and streamline regulatory requirements across those regulatory programs.

Environmental justice issues concerning the storage phase of CCS can be addressed through the SDWA UIC Program permitting process. The SDWA provides that EPA can deny permits or establish permit limits where such injection may "endanger" public health. As a result, in those States,[113] territories, and Federal lands where EPA issues permits, the SDWA provides EPA with authority to establish additional permit requirements to those already required under 40 C.F.R. §144.51 when EPA finds that injection activity may result in drinking water supply contamination that may adversely affect the health of minority, low-income, Tribal, or other vulnerable populations. Attention should also be devoted to avoid impacting areas traditionally used for subsistence consumption, sacred sites, and other culturally important practices.

Goal 3: Include clear standards, regulatory approaches, and legal or financial mechanisms that might be needed throughout the life of the CO_2 sequestration project (and beyond). A successful regulatory framework will include all requirements that must be complied with over the entire lifetime of a project (e.g., health and safety standards; operations; monitoring, reporting, and verification; financial assurance; long-term stewardship; and enforcement). For example, the current SDWA UIC framework includes requirements for site characterization, well construction, operation, closure, and post-closure monitoring, but does not address long-term stewardship of sequestration sites, or address liability after the post-injection site care period. Currently, liability would remain with the owner/operator of the injection well only through the operating life of the facility and the specified post-closure period. To change that situation, the SDWA UIC statute would need to be revised. Liability issues are discussed in more detail in Section IV.C of the report.

Goal 4: Promote national consistency, yet addresses existing differences in authorities between the onshore and offshore, and clearly articulate the role of States. SDWA's UIC Program regulates the underground injection of fluids into the subsurface onshore and the sub-seabed of State territorial waters to prevent endangerment of USDWs. Under the SDWA UIC Program, State and Tribal UIC programs have primary enforcement responsibility (or primacy) once their UIC programs have been approved by EPA. Technical capacity to operate the program will vary from State to State, along with how regulatory requirements are implemented. To facilitate deployment of well-managed CCS projects throughout the United States, minimum Federal standards will be important. It is important to note that EPA will not approve primacy applications from States that are unable to achieve minimum Federal standards as required under the SDWA § 1422. National consistency is also important to ensure that CO_2 emissions reductions associated with geologic sequestration of CO_2 can be included in future climate programs.

While the Federal Government does have authority for regulating CCS offshore, further clarity in statutory authority would ensure that it can provide the kind of comprehensive management

[113] References to "States" in this section also include Tribal governments.

described in this report. Under ideal circumstances, a unified framework for the regulation of offshore sequestration would be established under new legislation. An international agreement, the 1996 London Protocol to the 1972 Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (also known as the London Protocol), addresses offshore carbon sequestration in the sub-seabed. Two guidance documents were developed by the Parties to the London Convention and Protocol, the international body established to address prevention of marine pollution by dumping of wastes and other matter (i.e., ocean dumping of materials). The two documents together are intended to provide guidance in evaluating applications for sequestration of CO_2 into sub-seabed geological formations (and not in the water column), and the other restrictions applicable under the London Protocol. The Specific Guidelines include sections addressing, among other things, the conduct of a waste prevention audit, consideration of waste management options, consideration of the chemical and physical properties of the CO_2 stream, site selection and characterization, assessment of potential effects, monitoring and risk management, the issuance of permits, and the development of permit conditions.

The United States has signed and has been working toward ratification of the London Protocol for several years, and the London Protocol is on the Administration's Treaty Priority List for the 111th Congress. Senate advice and consent on ratification will require amending the language in the Marine Pollution, Research, and Sanctuaries Act (MPRSA) to address differences between the London Convention and the London Protocol. Conforming statutory amendments were proposed to the last Congress but would require re-submission to this Congress. The Administration is currently developing a revised MPRSA amendment package, and, will likely address amendments to the OCSLA either in this package or in a separate package, to submit to Congress. Such amendments would result in a comprehensive statutory framework for the leasing and regulation of sub-seabed sequestration facilities on the OCS. The Task Force recommends that the Administration commit to working toward a comprehensive framework for CCS that addresses a broad range of issues and applies the necessary environmental protections for offshore sequestration in a manner similar to the regulation of onshore sequestration.

Goal 5: Include strong compliance and enforcement mechanisms. A successful legal and regulatory framework will include compliance and enforcement mechanisms that cover all aspects of CCS. It may be necessary to expand and clarify areas of SDWA to ensure that the broader scope of CCS activities and their environmental impacts are covered.

The Federal government currently has authority under SDWA to collect information, conduct inspections, monitor compliance, and take civil or criminal action related to the protection of underground sources of drinking water.[114] The United States may also respond to an imminent and substantial threat to a source of drinking water, and take an enforcement action to remedy the situation.[115,116] Absent a specific regulatory or permit requirement, SDWA allows Federal information gathering and inspection under the SDWA UIC Program, by regulation, and only for regulatory development or determination of individual well owner or operator compliance with UIC program requirements. Adequate compliance and enforcement of all aspects of CCS may require the utilization of other environmental statutes and possibly the strengthening of some SDWA provisions.

Because SDWA is focused on the protection of drinking water sources, it may require clarification to support actions to address or remedy ecological or non-drinking water human health impacts arising from the injection and sequestration of CO_2.

The injection and sequestration of CO_2 will require access and authority to monitor the migration of CO_2 over long distances in large geologic formations beyond the property of the UIC well owner or area of review of the UIC permit. The UIC well owner/operator will need to install monitoring wells in an extended area, and State and Federal officials will need access to gather information for enforcement purposes. SDWA could be clarified to provide for extended access to property for monitoring and enforcement purposes and authority to request CCS-related information that may not required by UIC regulations.

CO_2 sequestration on a national scale may present opportunities for fraudulent conduct. It will be important to enhance SDWA's civil and criminal enforcement authorities (including, e.g., to provide significant sanctions for making false statements) to deter such behavior and ensure that a national CCS program meets its critical environmental goals. Methods to provide the capability to verify quantities of CO_2 captured, transferred and stored, and to document transfers of CO_2 through this system should be designed. Participation in such a monitoring, reporting and verification system should be mandatory for all recipients of CCS-related Federal funding, and the regime should be robust enough to detect and quantify CO_2 loss at every phase of capture, transport and storage. The accuracy of the data in this system should be verified through signed reports, certified by a responsible corporate official, to ensure there is a remedy in the event of an incorrect or fraudulent report. A market-wide CCS system is likely to require a robust accounting system of this type to ensure system integrity.

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[114] Section 300j-4(a)-(b), 42 U.S.C. § 1445(a)-(b); 40 C.F.R. §§ 144.17 and 144.27; section § 300h-2, 42 U.S.C. § 1423.

[115] Section 300i, 42 U.S.C. § 1431.

[116] The Federal government may exercise these compliance assurance and enforcement authorities in primacy States. Primacy States must also demonstrate that their programs are at least as stringent as Federal minimum requirements, which include specified compliance assurance and enforcement authority. 40 C.F.R. Part 145.

While other Federal statutes such as the CAA, RCRA, and CERCLA may provide stronger compliance and enforcement mechanisms where they are applicable, again, significant efforts by implementing agencies would be needed in order to address all possible impacts from CCS, appropriately balance environmental and safety objectives, reduce redundancy, and streamline regulatory requirements across those regulatory programs.

Finally, SDWA authorities could be expanded to allow EPA to serve as trustee or beneficiary of any financial instrument used to establish financial assurance under the UIC Program.

Goal 6: Create flexibility to account for site variability and is adaptive to accommodate learning. Various stakeholders have been advocating a CCS regulatory framework flexible enough to accommodate a wide range of technologies and geologies, and that can adapt as knowledge and experience are gained as the industry matures (CCS Regulatory Project, 2009b). These goals have been taken into account by EPA in the proposed Class VI rulemaking, which is largely performance-based, allows for site variability, provides for regularly updated plans, and includes requirements that must be updated as new information is collected. The anticipated framework will allow for a diversity of projects to be developed across the country and offshore, and reduce compliance costs while maintaining safe and effective projects. These goals have also been taken into account by EPA in the CAA GHG reporting proposal for CO_2 sequestration facilities by allowing such facilities to develop site-specific monitoring, reporting, and verification plans.

Goal 7: Build knowledge and public confidence by making information available and creating opportunities for public engagement. Public acceptance of CCS has been recognized as critical to its widespread deployment. The general public and local communities will seek access to information, involvement in decision-making processes, and assurance that projects are well-sited and well-managed. The SDWA UIC Program takes and requires primacy States to have actions by rulemaking (which has formal public participation elements), features Part 124 requirements for permitting (including appeal to the Environmental Appeals Board),[117] and allows citizens to bring suit challenging UIC program actions.[118] The public and affected States will be notified of and have the ability to comment on CO_2 sequestration projects via the NEPA and other regulatory programs as applicable. EPA's CAA GHG reporting proposal for CO_2 sequestration would also provide public information on the amount of CO_2 injected and stored in the United States.

Goal 8: Be designed to meet international obligations as appropriate. To ensure that the United States meets its international obligations and adheres to international law, the regulatory framework could consider agreements and treaties that may apply. For example, the

[117] 40 C.F.R. Part 124.

[118] Section 300j-8, 42 U.S.C. §1449.

United States is required to submit an annual Inventory of Greenhouse Gas Emissions and Sinks under the United Nations Framework Convention on Climate Change, which includes reporting of CCS. The United States is also party to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (referred to as the London Convention or LC). The 1996 London Protocol (LP) to the LC (Protocol) strengthens and updates the LC. The United States is not yet a Party to the Protocol, but has signed it. As a signatory, the United States must refrain from acts that would defeat the object and purpose of the Protocol, but is not bound by the terms of the Protocol itself. In 2006, the Protocol was amended by placing "carbon dioxide streams from carbon dioxide capture processes for sequestration" on the exclusive list of substances that may be considered for dumping under certain conditions. The effect of the amendment was to provide for sub-seabed sequestration of CO_2 under the LP subject to controls, including the issuance of a permit. Transboundary issues, such as tracking/regulating CO_2 plume movement across national boundaries, could also be considered.

VII. Approaches for Legal or Regulatory Structures to Deal with Potential Liabilities

As discussed in Section IV.C, many stakeholders have identified long-term liabilities associated with CO_2 sequestration as a potential barrier to CCS deployment. These potential long-term liabilities could be addressed using seven different general approaches: (1) reliance on existing legal and regulatory framework; (2) substantive or procedural limitations on claims; (3) Federal legislation facilitating private insurance coverage; (4) establishment of a liability fund; (5) government ownership or direct government liability; (6) governmental indemnification: and (7) transfer of long-term risk to the Federal government after site closure. These approaches, discussed in more detail below, are not mutually exclusive and can be combined in various hybrid formats.[119]

The purpose of the Task Force's analysis was not to recommend a specific approach for dealing with potential liabilities, but rather to evaluate the advantages and disadvantages of various approaches and recommend removal of certain options from consideration.

VII.A Existing Legal and Regulatory Framework

As discussed in Section IV.C.1.1, there already exist Federal and State laws governing CCS activities. In particular, several States have adopted legislation that provides for transfer of long-term liability to the State by various mechanisms. One option would be to not seek additional legal authority, and to proceed on the basis of this existing body of law.

A key question is whether, assuming liability concerns will in fact impair adoption of CCS technology, there are ways to address those concerns under this existing legal framework, or whether Congressional action would be required to address those concerns. The existing Federal framework largely does not provide for a release or transfer of liability from the owner/operator to other persons, although some States are experimenting with alternative approaches for addressing concerns about long-term liability under existing law. One mechanism involves States agreeing to take on the long-term liability by undertaking the CCS project themselves, by assuming liability from CCS operators, or by providing a mechanism for transfer of liability. At least six States, and possibly more, have already adopted various forms of legislation that would achieve this result.

Another option would involve designing CCS operations so that the Federal government acquires the CO_2 at the time of injection and sequestration facilities are Federally-owned, with the goal of preventing private parties from incurring risks of long-term liabilities. It appears,

[119] The discussion that follows reflects information and analysis contained in a number of preexisting reports, including EPA (2008); Wilson et al. (2008), Wilson, et al. (2007); and the IOGCC (2007).

however, that private entities that contribute CO_2 to such a reservoir still would have potential liabilities, as would any private contractors involved in the facility's operations, and that there are not mechanisms available under existing law to address those liabilities. Thus, this mechanism would probably not suffice to address all liability concerns those entities might have.

Appendix KAppendix provides a discussion of liability arrangements under existing DOE CCS programs. Under the FutureGen program, Illinois law provides for the State to accept liability. DOE has declined to accept liability under two other programs, the CCPI and the RCSP. Instead, liability under these two programs is presumably governed by State law and existing Federal law where applicable. This supports the view that State law may provide a possible basis for proceeding, at least in the short term.

The Task Force's preliminary assessment is that the existing mechanisms could be adequate to facilitate at least an initial group of five to ten commercial-scale operations. A group of States has already adopted legislation to address long-term liability from CCS operations; see Section IV.C.1.1. If additional States adopt similar legislation, that could suffice to provide the basis for early movers, including the five to ten commercial-scale projects planned by 2016. The Task Force would need to confirm that the State legislation in question adequately addresses potential sources of liability, including, for example, CERCLA. Nonetheless, under an approach that relies on the States to address long-term liability, the Task Force would emphasize that the Federal government will need to maintain a very active oversight role over the initial group of CCS facilities, and should not cede the oversight function to the States.

There are also reasons that economy-wide deployment (beyond the initial group of early movers) could require Federal legislation. If there are different liability regimes at the State level, the group of participating States may be narrow, and that may constrain the settings in which CCS can be deployed. Additionally, the number of participating States may be limited by the suitability of geologic formations; i.e., only some States or regions will be suitable for the commercial-scale development of CO_2 sequestration. Some States will be reluctant to adopt legislation on long-term liability, or may face fiscal constraints that prevent them from enacting effective legislative programs. If many States are in this category, CCS deployment may be geographically limited as a result. Moreover, circumstances that could give rise to the existence of long-term liabilities include inadequate oversight of siting of geologic sequestration locations, inadequate regulation of CCS activities, and/or operator error. Widespread cost-effective deployment of CCS has the potential to strain regulatory capacity, which in turn heightens these concerns. That suggests the need for an additional legal framework designed both to prevent liability from arising and to ensure that harms can be addressed in the event they do occur. Proper design of the initial five to ten projects may help to test these premises and develop information on appropriate regulatory approaches that might be included in such a framework.

Advantages: This approach avoids the need to seek new legal authority or Congressional action. Because the timing and scope of Congressional action cannot be predicted, this is a significant advantage. States could implement frameworks specific to their region and unique circumstances, which could encourage development of best practices. The lengthy process of creating a new regulatory framework could be avoided, which might allow demonstration projects to be implemented more quickly.

Disadvantages: Inconsistent State approaches to regulation could impede CCS projects that cross State lines. Potential parties could be discouraged from investing in projects if they perceive a barrier related to balance-sheet recognition of the cost of potential liabilities or the insurability of risks. Limitations in State resources and regulatory capacity may limit their ability to approve and oversee CCS activities, which may in turn constrain adoption of CCS.

VII.B Substantive or Procedural Limitations on Claims

Another approach to addressing long-term liability concerns would be to adopt substantive or procedural limitations on claims. These might include, for example, providing for removal of actions to Federal courts; establishing a uniform Federal standard of liability; and limiting or barring punitive damages.[120] Some commentators have proposed reliance on liability caps, at least for an initial group of projects (Jacobs and Stump, 2010). The Task Force assumes that any limitations on claims would principally address private claims against the entity; ongoing obligations imposed by the government, such as the obligation to monitor the site and respond to any problems that might develop, would not be appropriately limited in this way.

Advantages: Establishing uniform Federal standards may help to ease uncertainties from the business community and insurers over the extent of potential liabilities and address uncertain or inconsistent State standards. Federal liability standards could facilitate projects that cross State lines.

Disadvantages: Severe limitations on remedies could raise potential legal or constitutional concerns, depending on how they were drafted. They could also raise federalism issues, to the extent that the effect would be to displace State law. By contrast, more modest limitations on remedies may not suffice to reassure stakeholders who are concerned about long-term liability. Also, if remedies are limited, the result may be that harms to individuals and their property

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[120] There are a number of examples of statutes that modify or limit State remedies in various ways. For example, the Price-Anderson Act requires removal of claims to Federal court, 42 U.S.C. § 2210(n)(2) and 42 U.S.C. § 2014(hh), and bars punitive damages. Federal law contains a similar provision allowing removal of MTBE-related tort claims to Federal court. A Federal law imposes a range of limitations on the application State law to businesses selling qualified anti-terrorism products, including prohibiting punitive damages, capping damages at the level of (mandatory) insurance coverage, and prohibiting imposition of joint and several liability. 6 C.F.R.25.7 (2010). And CERCLA contains a provision establishing a uniform Federal period for accrual of statutes of limitations for State tort claims relating to hazardous waste sites. 42 U.S.C. § 9658.

associated with CCS activities go uncompensated, unless some other compensation mechanism is established. In addition, limitations on claims could raise moral hazard concerns.

VII.C Federal Legislation Facilitating Private Insurance Coverage

A third approach involves legislation that facilitates private insurance coverage of long-term liabilities. (The Task Force does not analyze the approach of establishing a pooled liability fund in this section; that option is instead discussed in the section that follows. The present discussion focuses only on approaches that rely on existing insurance companies and their capital.) The Task Force notes that the availability of private insurance is an important consideration, since insurance often is required by lenders and thus is a prerequisite to the availability of private financing for the construction of necessary facilities.

One approach for facilitating private insurance coverage would be to require owners or operators to purchase such insurance, thereby creating a pool of insured entities and a stream of premiums that may in turn allow insurers to provide coverage. That approach is reflected in the Price-Anderson Act, which mandates that the owners/operators of nuclear reactors obtain private insurance at prescribed levels. Additional information regarding the Price-Anderson private insurance approach is presented in Appendix I.

The Task Force anticipates that private insurance will be available and utilized up to the post-closure phase. Our understanding is that insurers are prepared to issue policies for CCS activities for that period.[121] However, preliminary discussions with insurers have indicated a reluctance to issue policies in the present to cover long-term (post-closure) CCS-related risks. Insurers state that they have difficulty valuing those risks because of their novelty that they are not institutionally suited to issuing policies where risks may not accrue for centuries or even longer, and that such policies would be highly unusual for their business.[122]

It is not clear whether government action could address these concerns, especially the second one, and induce insurers to issue long-term insurance policies to cover post-closure risk. Potential government actions might include: (1) mandating the purchase of insurance coverage; (2) requiring insurance only for a defined level of exposure (up to a specified dollar limit; liability might be capped at the insurance company limit or additional risks could be addressed through some other mechanism); and (3) allowing shorter-term policies and the periodic re-rating of insurance company risks. These three elements are all features of the existing hybrid insurance arrangements established for nuclear power facilities under the Price-Anderson Act. The operation of those arrangements is set forth in detail in Appendix I.

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[121] Insurers state that they may not currently be willing to issue policies covering the replacement cost of CO_2 lost from a CCS storage reservoir, however, due to the uncertainty as to the future per-tonne replacement cost.

[122] Communication from representative of Zurich Financial Services.

The Task Force recommends soliciting further input from the insurance industry to explore whether there are circumstances under which private insurers would issue insurance policies to cover long-term risks of CO_2 sequestration. As part of this analysis, the government would also need to make an independent determination as to whether the insurers in question can provide the necessary capital over the relevant time scale (which may, again, be measured in centuries). There are considerable uncertainties as to how insurers would be able to address this issue. Because of these uncertainties, and the statements of insurers that they will not issue this type of coverage, the Task Force does not provide a listing of advantages and disadvantages for this option.

VII.D Liability Fund

Many commentators and experts have proposed establishment of some form of liability fund (see, e.g., CCS Regulatory Project, 2009a; Jacobs et al., 2010). Such a fund would be a substitute for private insurance, in which the government takes on the function of pooling risks and evaluating claims. Examples of existing, similar funds include the Superfund,[123] the Oil Spill Liability Trust Fund,[124] and the National Flood Insurance Act of 1968.[125] The pooled industry insurance established by the Price-Anderson Act, under which the nuclear reactor industry is required (after a facility's mandatory commercial insurance policy is exhausted) to contribute to insurance to cover the costs of a cleanup in the event of an incident, also has some similarities to such an arrangement. It provides a pooling approach that is funded after an incident, rather than beforehand.

The fund could be administered either by the government or by a private entity (presumably with extensive governmental oversight), and could be supported through a fee on the underlying activity. The precise structure of the fee would depend on how the underlying activity was defined; it might take the form of a fee on each tonne of CO_2 sequestered, or of a

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[123] CERCLA, 42 U.S.C. 9601-9675, creates a fund for use in cleaning up contaminated sites. Monies for the fund originally derived from taxes on related industries and activities, and from recoveries of costs obtained from defined responsible parties.

[124] The Oil Spill Liability Trust Fund (OSLT) compensates parties for recovery and mitigation expenses in excess of the responsible party's limit on liability. There have been criticisms of the operation of this fund, however. See (Wood, 2009).

[125] The National Flood Insurance Act of 1968, as amended at 42 U.S.C. § 4001-4129, provides for the establishment of a government-administered fund supported by premiums paid by policyholders. Claims are paid out of the fund and the intent of the legislation is not to finance the fund from the U.S. Treasury. Unfortunately, for a number of reasons, the Fund has had to borrow from the U.S. Treasury in order to subsidize some policies and to replenish the Fund. *See Legislative Proposals to Reform the National Flood Insurance Program: Hearing Before the Subcomm. on Housing and Community Opportunity of the H. Comm. on Financial Resources,* 111th Cong. (2010) (statement of Orice Williams Brown, Director, Financial Markets and Community Investment, United States Government Accountability Office). Any CCS liability fund should be designed to avoid these difficulties.

fee imposed more broadly on energy production or large emitters. The amount of the fee would be based on a risk analysis (potentially varying by site characteristics), and would be tailored to generate insurance coverage or fund of a size adequate to address potential claims.

The fund should be designed to avoid moral hazard. There could be clear rules for drawing against the fund and safeguards against unapproved uses of fund monies. If not properly protected, the fund could be drained for other purposes unrelated to CCS long-term liability. The fund could have the ability to seek to recover its costs from responsible parties (e.g., those who failed to report required data or violated applicable requirements) Such authority both deters negligent conduct and helps to ensure that the fund is not depleted,

Operators could be required to make payments to the fund during the operational phase of their sites, because this would prevent operators from defaulting on future payment of fees; also, future legislation creating a market for CO_2 may generate a revenue stream during the operational phase, which would fund such payments. Transferring long-term liability away from the owner/operator creates the potential for moral hazard; a risk-based payment into a fund mitigates that moral hazard to some extent. (By contrast, payments assessed after an incident occurs may not have a similar incentive effect.) Appropriate funding is necessary to ensure that the fund is not depleted, in which case the costs for CCS liabilities could fall to the public or be left unaddressed.

Advantages: A liability funding mechanism would provide a source of funding to address any problems developing as a result of CCS activities. The costs would be paid by the relevant industry in advance; this is beneficial because the responsible entity might no longer exist by the time a long-term liability arose. Fund monies might also be helpful for certain other purposes, especially those that would help prevent liability from arising. Examples could be the costs of emergency response or of oversight and monitoring activities by State or Federal authorities. Depending on how the fund is designed, each operation could be completely responsible for its own post-closure liabilities, which can encourage responsible project management.

Disadvantages: A liability funding mechanism could be costly to establish and administer, and would impose additional costs on CCS activities. It could also be institutionally difficult to maintain the funding mechanism for the indeterminate period (possibly centuries). Also, a highly conservative approach to designing a liability fund could mean maintaining very large sums of money over this time period, which could have significant opportunity costs.

VII.E Government Ownership or Direct Liability

The fifth option involves the Federal government taking on ownership or direct liability for the risks of long-term CO_2 sequestration from the beginning of sequestration operations (that is, upon injection of CO_2). Government liability arguably could arise as a result of government planning, design, and construction of CCS facilities or government ownership of sequestration locations, equipment, or the CO_2 itself, or government operation of the CCS facility and equipment.

The precise analysis of governmental liability varies by legal context. As to tort claims, there are legal limits on Federal government liability under the Federal Tort Claims Act's (FTCA) Discretionary Function Exception, 28 U.S.C. 2680(a), and the FTCA's bar on strict liability claims. See *United States v. Gaubert*, 499 U.S. 315, 322-23, 325 (1991) (limited waiver of sovereign immunity contained in the FTCA does not extend to governmental activity that (1) did not violate a pertinent statute, regulation, or policy that prescribed a specific course of action and (2) was "susceptible to policy analysis" involving "social, economic, or political" policy considerations); *Laird v. Nelms*, 406 U.S. 797 (1972) (the FTCA does not permit suits based on theories of strict liability).

To the extent that the Federal government operates through contractors, those contractors would still have tort liability, but that liability would be limited by the Government Contractor Defense, set forth in *Boyle v. United Technologies Corp.*, 487 U.S. 500, 512 (1988).[126] In such situations, a company that has dealt fairly and above-board with the United States (and was not allegedly negligent in a manner beyond the following of specific government instructions) has a defense against tort suits. But, otherwise, the company can still be liable under State tort law.[127] Nor do such contractor defenses against tort claims foreclose congressional action providing for compensation of affected parties or penalties or assessments under applicable environmental laws, such as CERCLA.[128]

The legal analysis could be different under existing environmental statutes. To the extent that the government owns land on which sequestration occurs, this arguably could give rise to governmental liability by operation of law. Similarly, governmental ownership of CO_2; ownership of pipelines or other equipment; and even governmental oversight, financing, and encouragement of CCS activities could be claimed to give rise to governmental liability. (The government might contest the claim depending on the particular facts at issue.) There is no discretionary function or government contractor defense available under these statutes, and

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[126] Basing its ruling on the policy underpinnings of the FTCA's Discretionary Function Exception, the Supreme Court decided that State tort liability cannot be imposed when "(a) the United States approved reasonably precise specifications; (b) the equipment conformed to those specifications; and (c) the supplier warned the United States about dangers in the use of the equipment known to the supplier but not to the United States."

[127] While most circuits have ruled that the Government Contractor Defense applies to all government contractors, the Ninth Circuit has ruled that the defense only applies to military equipment.

[128] In high-visibility situations, such as the destruction of much of Texas City, Texas, due to an explosion of fertilizer bound for war-ravaged Europe in 1947 and exposure to radiation of "downwinders" in the wake of above-ground nuclear testing during the height of the Cold War, Congress acted with either private legislation or administrative programs funded by the Federal taxpayers to compensate those injured.

government contractors that are involved in geologic sequestration operations in any of a range of ways would not necessarily be immune from such liability.

Advantages: Structuring a program so that the government is directly liable for CCS activities, and no private party has remaining liability, could reduce the complexity of assigning long-term liability.

Disadvantages: Although this approach would add the government as a liable party, it would not necessarily eliminate CERCLA liability or common-law tort liability for private parties. For example, completely eliminating a party's status as a CERCLA potentially responsible party could be difficult without statutory or regulatory changes; although there is precedent for making such changes, they are quite infrequent. Thus, it is not clear whether this approach will entirely address stakeholder concerns. Moreover, if the government takes on liability by these methods, as a result of its role in endorsing or promoting CCS, rather than intentionally undertaking certain liabilities as part of a structured program, various problems may result. First, there will be less opportunity to set baseline rules governing liability and cleanup. Because the government will already be a liable party, it might find it difficult to condition its own financial support on compliance with a particular regulatory regime. Second, there will be significantly less incentive for private parties and States to take precautions to prevent harm.

VII.F Governmental Indemnification

Governmental indemnification is another approach to handling the liability risks of long-term geologic sequestration. However, under the Anti-Deficiency Act, the United States may not agree to open-ended indemnification arrangements absent specific Congressional authorization. See 31 U.S.C. 1341(a)(1)(B). Such authorizations have rarely been granted due to their inherent open-ended risk to the Federal government and taxpayers. Accordingly, sound public policy and legislative precedent counsel that authority to indemnify be strictly limited to activities of absolutely vital national security interests, and then only when private insurance is unavailable (e.g., agreements indemnifying Department of Energy contractors for liability arising out of nuclear incidents; and agreements indemnifying certain Department of Defense contractors). See Pub. L. No. 85-804 (codified as 50 U.S.C. § 1431 *et seq.*); the Price-Anderson Act, 42 U.S.C. § 2210; and *Hercules Inc. v. United States*, 516 U.S. 417, 426-29 & n.11 (1996). Additional information regarding the indemnification option appears in Appendix J.

Advantages: As with several of the other options, indemnification would provide additional certainty to industry.

Disadvantages: In addition to the statutory requirements discussed above, and the dangers of setting unnecessary precedents for providing Federal indemnification, indemnification is questionable as a matter of policy because it potentially severs day-to-day control of an activity from the associated costs and risks, and thereby blurs or reduces accountability.

VII.G Transfer of Liability to the Federal Government after Site Closure and Governmental Certification

Another approach to dealing with liabilities from long-term CO_2 sequestration is to provide for the transfer of non-Federal entity liability to the Federal government after site closure and governmental certification, with private liability limited to circumstances similar to those prescribed for liability under Government Contractor Defense standards. The approach could apply to both compensatory as well as performance liabilities. A number of commentators have endorsed this approach, which is a variation on the option discussed above involving government ownership or direct liability (Jacobs et al., 2010). If an analysis indicates that risks will diminish significantly after a particular number of years following completion of the sequestration, Federal regulators may be able to certify that the CO_2 is safely sequestered and will continue to remain so. Upon such certification, liability could be transferred to the Federal government or a Federal corporation. As to tort claims, liability would be limited to activities that are outside the Discretionary Function Exception, discussed above. As long as the United States did not violate any self-imposed specific obligations and its decisions were susceptible to policy analysis, there could be no tort liability against the United States. Under this approach, the former private owners/operators of the sites would no longer be potentially liable following certification, unless an injured party or government agency could affirmatively show that the former owner/operator failed to meet certain standards associated with the certification process. For example, if the former owner/operator failed to follow pertinent Federally mandated specifications or withheld adverse information from the United States, liability would attach.[129]

Advantages: As with several of the other options listed here, this approach would provide additional certainty to industry, something that could be very important given the arguably insurmountable difficulties inherent in costing private insurance for the post-closure period. Given the uncertainties as to whether specific private entities will still exist in the extremely long time periods associated with CO_2 sequestration, putting the government in charge provides the greatest assurance that an entity will be available to perform stewardship responsibilities. Moreover, the requirement that CCS operators meet certain standards in order to qualify for a transfer of liability (and that the transfer is legally ineffective if it later is determined that those standards were not met) would provide an additional mechanism for oversight of participants in CCS activities, and lessen the moral hazard problem.

Disadvantages: As with the other approaches restricting liability, this option could create some moral hazard. Moreover, unless the statute authorizing a transfer of liability expressly

[129] Industry stakeholders indicated in conversations with the Task Force that a transfer of liability would be of significant value in addressing concerns about long-term risks even if it included these types of limitations on the transfer of liability.

encompasses environmental laws such as CERCLA, there is no assurance that the Federal government's assumption of long-term liability will provide the former owners/operators with the sort of immunity they would have from tort suits. Also, while some States have already adopted laws under which they would assume liabilities in a similar manner, as described above, these State laws do not exempt the owners/operators from any potential liabilities under Federal law. Such liability is, in theory, potentially large and open-ended, and it is very unusual for the United States to assume such liability that has been incurred by other entities. Monitoring and remediation responsibilities are generally undertaken by the private sector in the first instance in other contexts (such as closure of hazardous waste sites), and the private sector is generally thought to be able to perform these functions.

VIII. Options for Federal Government Action on Public Outreach and Education

Public outreach and education is critical to the deployment of any new technology. CCS will require that the Federal and State governments work to educate the general public and other stakeholders on the facts about CCS, including the benefits of the technology for the economy and as a tool to mitigate GHG emissions. Several options could be pursued to facilitate CCS outreach and education for communities and the general public.

Option 1: **Support social science research to better understand the elements and potential extent of concerns around CCS.** A coordinated effort among Federal agencies, industry, and NGOs could be undertaken to gather information and evaluate potential key concerns around CCS in different areas of the United States. To inform a larger engagement strategy, it would be helpful to first understand how the public may perceive CCS, and how that perception changes from region to region. As indicated in recent literature, only a small percentage of the public is aware of CCS and how it may play a role as a technology to mitigate GHGs and climate change. Consequently, there is significant opportunity to inform the public debate. Research on likely concerns and successful ways to address these concerns will improve public outreach initiatives.

Option 2: Develop and implement a public outreach initiative on CCS, drawing on lessons learned from previous projects. This initiative will be critical to both near-term and long-term CCS deployment. A comprehensive outreach strategy could be developed between the Federal government, industry, and NGOs. It could be built on the experience and lessons learned from CCS stakeholders, such as RCSP, and include regulatory agencies, power companies, oil and natural gas producing companies, and NGOs. Roles of agencies and other key players could be defined and coordinated through an advisory board. Materials could be developed and disseminated through different agency websites but also linked through a common portal for information. This strategy will have two components, based on two different audiences: 1) a broad strategy for public outreach, targeted at the general public and decision makers; 2) a more focused engagement with communities that are candidate for CCS projects.

Broad Public Outreach

Federal agencies should develop a coordinated strategy with NGOs, project developers, and other stakeholders to educate the public about CCS. Studies have shown that perceptions about CCS generally become more positive with additional information. Therefore, it will likely be more efficient to proactively initiate efforts to educate the public about CCS prior to the active, widespread development of CCS projects. As demonstrated in Barendrecht, Netherlands, once projects have been initiated and potentially negative information about CCS has been communicated to the public from other sources, it could be more time-intensive and expensive to work from a defensive position to educate people about the positive aspects of CCS. Federal activities to engage the general public should include direct engagement and interaction, rather than just providing information.

Project Community Outreach

Acceptance from communities where projects are planned will be critical, so community engagement activities warrant a specialized strategy. Engagement should follow best practices that have been identified by a number of studies and groups (discussed further below). Communities should be informed about what CCS is, why it is being pursued, benefits, risks, and regulations in place to ensure safe and secure sites.

The project developer will most likely play the central role in any community outreach efforts, but a role may exist for the Federal government as well. Each project will require a different strategy and level of effort for public engagement, depending largely on a community's past experiences with industry or energy projects. Project developers will lead the organizational team for community outreach and engagement, but where appropriate the Federal government can advise on best practices and lessons learned from RCSP injection projects; it can also provide standardized education materials.

DOE, through its *Public Outreach and Education Best Practices Manual*, provides lessons learned from the RCSP pilot-scale and large-scale injection projects. This manual focuses on the key elements of a successful community engagement strategy. RCSP experience confirms that the development of trust between the host or project developer and local community greatly decreases the potential for opposition. Therefore, proactive and interactive communication between the host and the community will be critical to public acceptance (DOE, 2009).

Option 3: Incorporate Principles into Regulations. Environmental laws often require or provide the opportunity for public comment and input into permitting processes. Federal regulations bearing upon CCS, or any new relevant legislation, could incorporate such mechanisms to ensure a formal process exists for community or stakeholder involvement.

For example, EPA, under the proposed class VI rule for sequestration of CO_2, includes public engagement requirements of the public notice of pending sequestration site permitting actions. The permitting authority would be required to provide public notice (newspaper advertisement, postings, mailing to interested parties) and a 30-day comment period for public input. The permitting agency would then be required to prepare a responsiveness summary that would then become public record. In addition, all Federal funded actions or projects being constructed through Federal lands are required to comply with NEPA, which has requirements for public engagement.

Option 4: Develop Clearinghouses of High-Quality Information on CCS. Over the past several years, Federal agencies, the RCSP, industry, trade organizations, and others have developed and publicized an abundance of materials concerning CCS, including best practice manuals, scientific studies and journal articles, and basic educational materials. As part of the broader engagement strategy, the Federal government could establish a Federal clearinghouse online, where the public can access unbiased, high-quality information on CCS. While such material can currently be found across various websites from different organization, centralizing some of the higher-quality material could facilitate public familiarity with CCS. The website would follow Federal government guidelines for accessibility for broad audience. This gateway could also act as a gateway to other organizations that are providing similar material.

Separately, and in order to address community concerns around planned geologic sequestration sites, Federal agencies could work together to develop a web-accessible "toolkit" for project developers and regulators. This interagency toolkit could be developed with input from DOE (best practices from RCSP), EPA (permitting/regulatory processes), and DOT (pipeline transportation and siting). The toolkit could build on the principles and tools discussed in the best practices from the RCSP Public Outreach and Education manual and regulations for public engagement. These could be used from as early as possible and throughout the development of the project. The toolkit could also include a broad spectrum of educational materials, from various regulatory agencies to educate potential neighbors of sequestration sites about CCS technologies, site characterization processes, risk assessment and mitigation, and the process of sequestration.

Option 5: Provide support for third-party public outreach efforts. As mentioned, in order to maximize the chances for project success, it is necessary to plan and integrate public outreach efforts early in the process, and to engage stakeholders from different organizations on developing the consensus-based messages that may be necessary to communicate to the public. Working with a trustworthy messenger is an important first step since the credibility of the person or organization delivering the information can make a significant difference how the public reacts.

The Federal government could help facilitate this through various initiatives. For example, a Federal department or agency could assist an interstate compact or a Federal advisory group that could advocate for State interests in CCS-related activities. Or the Federal government could work with NGOs involved in the development and dissemination of CCS-related information in project communities.

Option 6: Encourage Opportunities for Early Success. Early successes with the deployment of new technologies are invaluable in providing evidence to the general public and other stakeholders that a new technology is safe, reliable, and beneficial. Real and inferred technical and economic risks may lead to social perception issues that could affect future deployments. Several successful early projects would demonstrate to the public that CCS technologies would be effective in mitigating GHG emissions, and could be widely and safely deployed after 2020.

The Federal government could take steps to ensure that early projects maximize chances for successful deployment. Some of these steps are touched upon elsewhere in this report. Other steps could include identification and characterization of potential sequestration sites on Federal lands. Proactive efforts to fully characterize these sites, assess the risks, and perform programmatic reviews of the projects' impacts and infrastructure requirements in the region could provide the information necessary to communicate with stakeholders the impacts and benefits of conducting CCS at these sites.

IX. Conclusions and Recommendations

IX.A Conclusions

- There are no insurmountable technological, legal, institutional, or other barriers that prevent CCS from playing a role in reducing GHG emissions.
- Widescale cost-effective deployment of CCS will occur only when driven by a policy designed to reduce GHG emissions. Ultimately, comprehensive energy and climate legislation will provide the largest incentive for CCS deployment as an option for climate change mitigation, because it will create a stable, long-term, market-based framework to channel private investment into low-carbon technologies.
- Existing Federal programs are being used to deploy at least five to ten large-scale integrated CCS projects. These projects, expected to be online by 2016, are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities. Early CCS projects face challenges related to climate policy uncertainty in addition to the challenges associated with cost, performance, legal and regulatory uncertainty, and early project technology risks. Prior to enactment of a comprehensive climate policy, early climate change mitigation projects such as these will rely on other incentives.
- RD&D can enable deployment of CCS by helping to reduce project uncertainty and improve technology cost and performance. The focus of RD&D is twofold:
    - Demonstrate the operation of current CCS technologies integrated at an appropriate scale to prove safe and reliable capture and storage.
    - Develop improved CO_2 capture component technologies and advanced power generation technologies to significantly reduce the cost of CCS, to facilitate widespread cost-effective deployment after 2020.
- Increased Federal coordination would enhance the government's ability to assist these projects by providing more efficient incentives and/or addressing barriers.
- CCS projects are proceeding under existing laws. Developing and clarifying regulatory requirements for CCS would reduce uncertainty for early projects and ensure safe and effective deployment. Additional Federal actions to enhance regulatory authority, address long-term liability, and strengthen stewardship frameworks could enable wider deployment. Some of these actions would require additional legislative authority.
- Open-ended Federal indemnification should not be used to address long-term liabilities associated with CO_2 storage.
- International collaboration complements domestic efforts on CCS and facilitates its global deployment.

- Public awareness and support are critical to the development of new energy technologies and are widely viewed as vital for CCS projects.

IX.B Recommendations

IX.B.1 Early Projects

Establish a Federal Agency Roundtable and Technical Committee to Facilitate Early Projects.

To ensure the success of early projects, including five to ten commercial CCS demonstrations by 2016, DOE and EPA should create a Federal agency roundtable to act as a single point of contact for project developers seeking assistance to overcome financial, technical, regulatory, and social barriers facing planned or existing projects. As needed, this roundtable should provide technical support to permitting authorities and permit applicants.

DOE and EPA should create a technical committee composed of experts from the power and industrial sectors, NGOs, State officials, and academia. This group could provide input on a range of CCS technical, economic, and policy issues.

Increase Coordination in Applying Drivers and Incentives to Enhance the Government's Ability to Assist Early Projects.

To ensure the success of five to ten commercial demonstration projects by 2016, DOE, in coordination with EPA, Treasury, and USDA, should track the use and efficacy of Federal financial support for CCS projects. Increased coordination will:

- enhance the government's ability to tailor Federal funding and assistance to each project's market context (such as whether the project involves publicly owned utilities, independent power producers, or competitive industrial sources);
- improve the clarity and transparency of eligibility criteria for projects to receive Federal support; and
- enable the Administration to allocate resources efficiently and more effectively consult with Congress and the States on the efficacy of existing incentives.

DOE should determine if early projects will sufficiently demonstrate an adequate breadth of capture technologies and classes of storage reservoirs to enable widespread cost-effective CCS deployment. This assessment will allow the Administration to target any remaining technology gaps in a manner consistent with addressing market failures.

Ensure that Relevant Agencies Work Quickly and Collaboratively to Propose, Finalize, and Implement the Regulatory Framework to Ensure Safe and Effective CCS Deployment.

Federal agencies should work together to design requirements for CCS using existing authorities in complementary ways.

- By late 2010, EPA should simultaneously:
  - finalize rulemakings for geologic sequestration wells under SDWA and GHG reporting for CO_2 storage facilities under CAA;
  - propose RCRA applicability rule for CO_2 that is captured from an emission source for purposes of sequestration; and
  - develop guidance to support implementation of these rules.
- By late 2011, EPA should finalize the RCRA applicability rule.
- EPA, USDA, and DOI should immediately formalize coordination and prepare a strategy to develop regulatory frameworks for onshore and offshore Federal lands.

Federal agencies should work together to enhance regulatory and technical capacity for safe and effective CCS deployment. Specifically,

- EPA, in coordination with DOE and DOI, should develop capacity-building programs for UIC regulators. Educating permit writers and other key officials will greatly enhance their capability and efficiency in issuing and enforcing technically sound permits. These programs should leverage existing efforts such as the DOE RCSPs.
- Federal agencies should begin to develop NEPA analyses related to CCS as early as possible to help ensure timely completion of environmental reviews. Where appropriate to Federal agency decision-making, agencies should consider development of Programmatic Environmental Impact Statements for use in tiered NEPA analysis and initiate this process. CEQ should consider development of CCS-specific NEPA guidance.
- DOE and EPA should identify data needs and tools to support regulatory development, permitting, and project development.
- EPA and DOE should study methods to monitor and account for CO_2 as it moves from capture, through a pipeline or other transportation system, to a storage facility. Because system design is likely to be time-consuming, Federal agencies should begin to put in place the basic architecture of such a system.

Enhance and Coordinate Public Outreach to Raise Awareness of CCS.

DOE, DOI, and EPA should:

- Coordinate among Federal agencies, States, industry, and NGOs to gather information and evaluate potential key concerns around CCS in different areas of the United States.
- Develop a comprehensive outreach strategy between the Federal government, industry, and NGOs. This strategy will have two components: a broad strategy for public outreach, targeted at the general public and decision makers, and a more focused engagement with communities that are candidates for CCS projects.
- Immediately establish a clearinghouse for public access to unbiased, high-quality information on CCS.
- Develop outreach tools for project developers and regulators with input from DOE (best practices from RCSPs), EPA (permitting/regulatory processes), DOT (pipeline transport), and DOI (Federal lands).

IX.B.2 Wider Deployment

Address Key Market Drivers.

Congress should enact comprehensive energy and climate legislation. The Administration should apply the key principles in this report and lessons learned from early projects to evaluate whether further drivers and incentives are needed to enable widescale deployment of advanced CCS technologies as a potential climate change mitigation option.

Enhance Regulatory and Long-term Liability and Stewardship Framework.

Congress should consider whether changes to statutory authorities to facilitate regulatory development and implementation are necessary. Revisions to SDWA could provide enforcement and compliance assurance and financial assurance authorities necessary to support wider CCS deployment. Ratification of the London Protocol (LP) and associated amendment of the Marine Protection, Research, and Sanctuaries Act (MPRSA) as well as amendment of the Outer Continental Shelf Lands Act (OCSLA) will ensure a comprehensive statutory framework for the storage of CO_2 on the outer continental shelf.

DOE and EPA, in consultation with other agencies, should track regulatory implementation and consider whether additional statutory revisions are needed. These actions will enable the Administration to more effectively consult with Congress and the States on the efficacy of the existing framework.

By late 2011, EPA, in coordination with DOE, DOJ, and Treasury, should further evaluate and provide further recommendations to address long-term liability and stewardship in the context of existing and planned regulatory frameworks. Of the seven options identified by the Task Force, the following four approaches should be considered (noting that a recommendation may include a hybrid of these or other approaches):

- Reliance on the existing framework for long-term liability and stewardship.
- Adoption of substantive or procedural limitations on claims.
- Creation of a fund to support long-term stewardship activities and compensate parties for various types and forms of losses or damages that occur after site closure.
- Transfer of liability to the Federal government after site closure (with certain contingencies).

Promote International Cooperation

DOE, EPA, State Department, and other interested agencies and stakeholders should continue, and where appropriate enhance, engagement in international collaborative efforts on CCS. These activities assist in global penetration of CCS technologies, leverage U.S. funding, and increase access to international expertise and experiences. In addition, international cooperation on CCS could potentially open markets to U.S. companies, while demonstrating U.S. leadership.

X. List of Acronyms

ACES	American Clean Energy and Security Act of 2009
AEP	American Electric Power
API	American Petroleum Institute
ARRA	American Reinvestment and Recovery Act
ASME	American Society of Mechanical Engineers
ASU	Air separation unit
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management, Regulation, and Enforcement
CAA	Clean Air Act
CCPI	Clean Coal Power Initiative
CCS	Carbon capture and storage
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
C.F.R.	Code of Federal Regulations
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
CZMA	Coastal Zone Management Act
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EIA	Energy Information Administration
EIS	Environmental impact statement
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-To-Know Act
FERC	Federal Energy Regulatory Commission
FLPMA	Federal Land Policy and Management Act
FTCA	Federal Tort Claims Act
GHG	Greenhouse gas
GW	Gigawatts
H_2	Hydrogen
ICCS	Industrial Carbon Capture and Storage
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
ILI	Inline inspection
INGAA	Interstate Natural Gas Association of America
IPCC	Intergovernmental Panel On Climate Change

LC	London Convention
LGP	DOE Loan Guarantee Program
LP	London Protocol
MEA	Monoethanolamine
MIT	Massachusetts Institute of Technology
MLA	Mineral Leasing Act
MPRSA	Marine Protection, Research, and Sanctuaries Act
MVA	Monitoring, verification, and accounting
MW	Megawatt
MWe	Megawatt electrical
N_2	Nitrogen
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGO	Non-governmental organization
NHPA	National Historic Preservation Act
NO_x	Nitrogen oxides
NRAP	National Risk Assessment Partnership
O_2	Oxygen
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
PC	Pulverized coal
PEIS	Programmatic environmental impact statement
PM	Particulate matter
PHMSA	Pipeline and Hazardous Materials Safety Administration
R&E	Research and experimentation
RCRA	Resource Conservation and Recovery Act
RCSP	Regional Carbon Sequestration Partnerships
RD&D	Research, development, and demonstration
RUS	Rural Utilities Service
SCADA	Supervisory control and data acquisition
SDWA	Safe Drinking Water Act
SO_x	Sulfur oxides
UIC	Underground Injection Control
U.S.C.	United States Code
USDW	Underground source of drinking water
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
WGS	Water-gas shift

XI. References

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Appendices to the Report of the Interagency Task Force on Carbon Capture and Storage

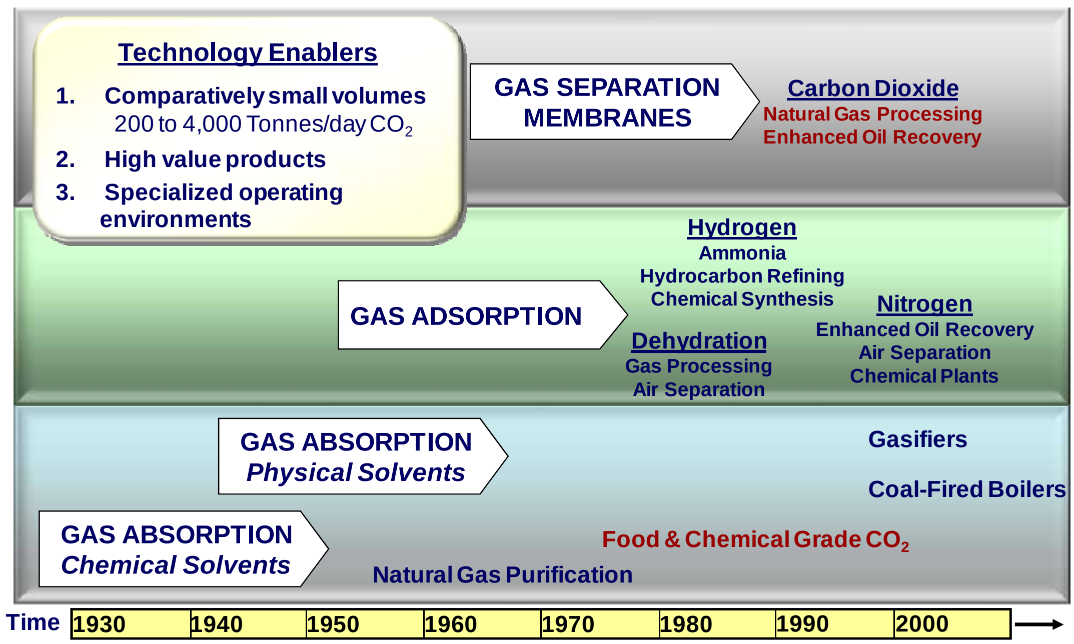
Appendix A. CO_2 Capture – State of Technology Development: Supplementary Material

Approximately 70-90 percent of the cost of CCS is associated with capture. This appendix presents a brief history of CO_2 capture technology, the current state of technology development, and planned large-scale demonstration projects. It is an expanded version of the CO_2 capture section in the main body of the report.

A.1 CO_2 Capture History

Although CO_2 capture is new to coal-based power generation, removal of CO_2 from industrial gas streams is not a new process. The history of removal of CO_2 from industrial gas streams is depicted in Figure A-1.

Figure A-1. Previous Experience with Removal of CO_2 from Gas Streams



Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. Chemical solvents are used to separate CO_2 from gas streams containing three to 25 percent CO_2. In the 1940s, physical solvents were developed to absorb CO_2 from gas streams with higher CO_2 concentration (25 to 70 percent) and higher pressure (approximately 1,500 Psia), such as those encountered in high-pressure natural gas processing. In the 1950s and 1960s, gas adsorption processes were developed to remove CO_2 from gas streams. In the 1970s and 1980s, gas separation membranes were developed (Kohl and Nielsen, 1997).

The licensing history of the Econamine FG process (one of a handful of commercially available amine-based chemical solvent CO_2 separation processes) provides a good example of past applications of CO_2 removal technologies (Chapel et al., 1999). Prior to 1999, 25 capture facilities were built that captured CO_2 quantities ranging from 635 to 365,000 tonnes/year using the Econamine FG process (Table A-1).

Table A-1. CO_2 Capture Plants Built Prior to 1999 Using the Econamine Process

Owner	Location	Fuel	Capture Rate (tonnes per year)	CO_2 Use
Carbon Dioxide Technology	Lubbock, TX	Natural Gas	331,000	EOR
Northeast Energy Associates	Bellingham, MA	Natural Gas	106,000	Food Industry
Luzhou Natural Gas	Sechuan, China	Natural Gas	53,000	Urea Plant Feed
Sumitomo Chem/Nippon Oxygen	Chiba, Japan	Heavy Fuel Oil	53,000	Food Industry
Indo Gulf Fertilizer	Uttar Predesh, India	Natural Gas	50,000	Urea Plant Feed
Prosint	Rio de Janeiro, Brazil	Natural Gas	30,000	Food Industry
N-Ren Southwest	Carlsbad, NM	Natural Gas	30,000	EOR
Messer Greisheim do Brazil	Sao Paulo, Brazil	Natural Gas	26,000	Food Industry
Liquid Air Australia	Altona, Australia	Natural Gas	20,000	Food Industry
Liquid Air Australia	Botany, Australia	Natural Gas	20,000	Food Industry
Messer Greisheim do Brazil	Sao Paulo, Brazil	NR	16,000	Food Industry
San Miguel Corp.	San Fernando, Philippines	NR	15,000	Food Industry
European Drinks	Sudrigiu, Romania	NR	12,000	Food Industry
Cervezaria Baveria	Barranquilla, Colombia	NR	8,000	Food Industry
Paca	Israel	NR	8,000	Food Industry
Industrial de Gaseoses	Quito, Ecuador	NR	2,000	Food Industry
Pepsi Cola	Manila, Philippines	NR	2,000	Food Industry
Pepsi Cola	Quezon City, Philippines	NR	2,000	Food Industry
Cosmos Bottling	San Fernando, Philippines	NR	2,000	Food Industry
Coca Cola	Cairo, Egypt	NR	2,000	Food Industry
Azucar Liquida	Santo Domingo, Dom. Rep.	NR	2,000	Food Industry
Tokyo Electric Power	Yokosuka, Japan	Coal	1,600	Pilot Plant
Boundary Dam Power Plant	Saskatchewan, Canada	Coal	1,000	Pilot Plant
Kansei Electric Power	Osaka, Japan	Natural Gas	635	Pilot Plant
Sundance Generating	Alberta, Canada	Coal	635	Pilot Plant

NR - Not Reported

The ten largest facilities captured more than 20,000 tonnes of CO_2/year. Nine of these large facilities captured CO_2 from flue gas generated by the combustion of natural gas. The one exception used flue gas generated by firing a variety of fuels, including heavy fuel oil. The process was also used for pilot-scale testing of three coal-fired applications capturing 635 to 1,600 tonnes/year. The captured CO_2 from these facilities was used for enhanced oil recovery (EOR), urea production, and in the food and beverage industry. The capture rates for these facilities reflect the fact that they were built to serve a specific commercial market for CO_2. Other amine-based processes (e.g., ABB/Lummus) were implemented at similar capture rates during this time period. By comparison, a single 550-MW net output coal-fired power plant capturing 90 percent of the emitted CO_2 will need to separate approximately five million tonnes per year of CO_2. This large difference in capacity represents a significant barrier to widespread commercial deployment of CO_2 removal technologies for coal-fired power plants (DOE, 2010a).

A 2009 review of commercially available CO_2 capture technologies identified 17 facilities (using both chemical and physical capture solvents) in current operation (Table A-2) (Dooley et al., 2009). These facilities include four natural gas processing operations and a syngas production facility in which approximately 1 million tonnes of CO_2 are captured per year. The largest (the Shute Creek natural gas processing plant in Wyoming) captures 3.6 million tonnes per year, which approaches the volume required for capture at electric generating plants. However, the degree to which experience with natural gas processing is transferrable to separation of power plant flue gases is unclear, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants presents significant cost and operating issues that must be addressed in order to facilitate widespread, cost-effective deployment of CO_2 capture. CO_2 Capture in Coal-Fired Power Generation

In general, CO_2 capture technologies applicable to coal-fired power generation can be categorized into three approaches: pre-, post-, and oxy-combustion (IPCC, 2005; DOE, 2007). Pre-combustion systems are designed to separate CO_2 and hydrogen (H_2) in the high-pressure syngas produced at IGCC power plants. Post-combustion systems are designed to separate CO_2 from the flue gas—primarily nitrogen (N_2)—produced by fossil-fuel combustion in air. This is the technology type that would be applicable to most of the existing coal-fired power plants in the United States. Oxy-combustion uses high-purity oxygen (O_2) rather than air to combust coal and therefore produces a highly concentrated CO_2 stream.

Application of any of these approaches results in an increase in the cost of electricity and in a decrease in electricity output, or an energy penalty (Rubin, 2008). The energy penalty occurs as a result of the diversion of some of the energy produced by the plant (in the form of both steam and electricity) in order to operate the CO_2 capture process. Thus the diversion of energy represents a loss in revenue as well as a loss of electrical power that must be recuperated by some other means.

Table A-2. Summary of CO_2 Capture Facilities Operating in 2009

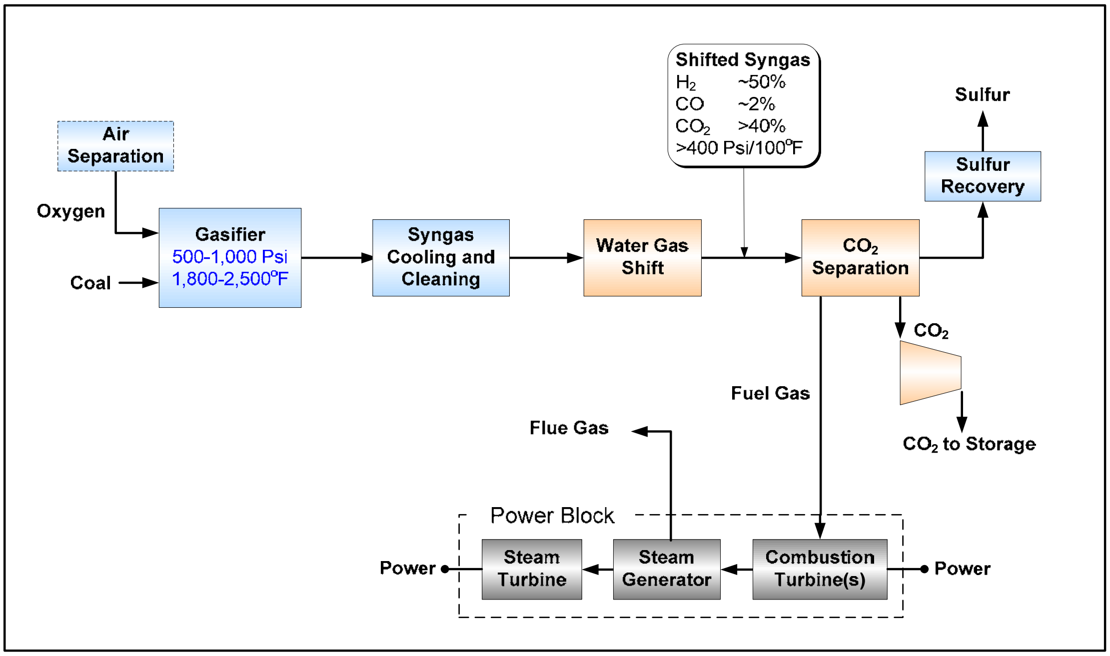
CO_2 Source/Project Name	Location	Capture Rate (tonnes per year)	Capture Technology	CO_2 End Use
Post-Combustion Capture from Pulverized Coal-fired Electric Power Plants				
AES Warrior Run Power Plant	Cumberland, MD	109,000	Amine	Food/beverage
AES Shady Point Power Plant	Panama, OK	66,000	Amine	Food/beverage
Searles Valley Minerals	Trona, CA	270,000	Amine	Soda Ash Production
AEP Mountaineer Power Plant	New Haven, WV	100,000	Ammonia	Geologic Storage
CO_2 Capture from Coal Gasification				
Great Plains Synfuels Plant	Beulah, ND	1,800,000	Rectisol	EOR
CO_2 Capture from Oxygen-fired Coal Combustion				
Vattenfall Schwarze Pumpe Plant	Germany	68,000	Compression	Various Industrial
Post-Combustion Capture from Natural Gas-fired Facilities				
Sumitomo Chemicals Plant	Japan	54,000	Amine	Food/beverage
Prosint Methanol Production Plant	Brazil	27,000	Amine	Food/beverage
CO_2 Capture from Natural Gas Reforming				
Indian Farmers Fertilizier Co.	India	544,000	Amine	Manufacturing
Petronas Fertilizer	Malaysia	50,000	NR	Urea Production
Ruwais Fertilizer Industries	UAE	131,000	Amine	NR
Luzhou Natural Gas Chemicals	China	50,000	Amine	Urea Production
CO_2 Capture from Natural Gas Production				
Snohvit LNG Project	Norway	635,000	Amine	Geologic Storage
Sleipner West Field	Norway	900,000	Amine	Geologic Storage
In Salah Natural Gas Production	Algeria	1,090,000	Amine	Geologic Storage
Shute Creek Natural Gas Processing	La Barge, WY	3,630,000	Selexol	EOR
Val Verde Natural Gas Plants	Terrell/Pecos, TX	1,270,000	NR	EOR
DTE Turtle Lake Gas Processing	Otsego, MI	181,000	Amine	EOR/Geologic Storage

NR - Not Reported

A.1.1 Pre-Combustion CO_2 Capture

Pre-combustion capture is applicable mainly to gasification (Integrated Gasification Combined Cycle) plants, where fuel is converted into gaseous components by applying heat under pressure in the presence of steam and limited O_2, as shown in Figure A-2.

Figure A-2. Pre-Combustion CO_2 Capture for an IGCC Power Plant

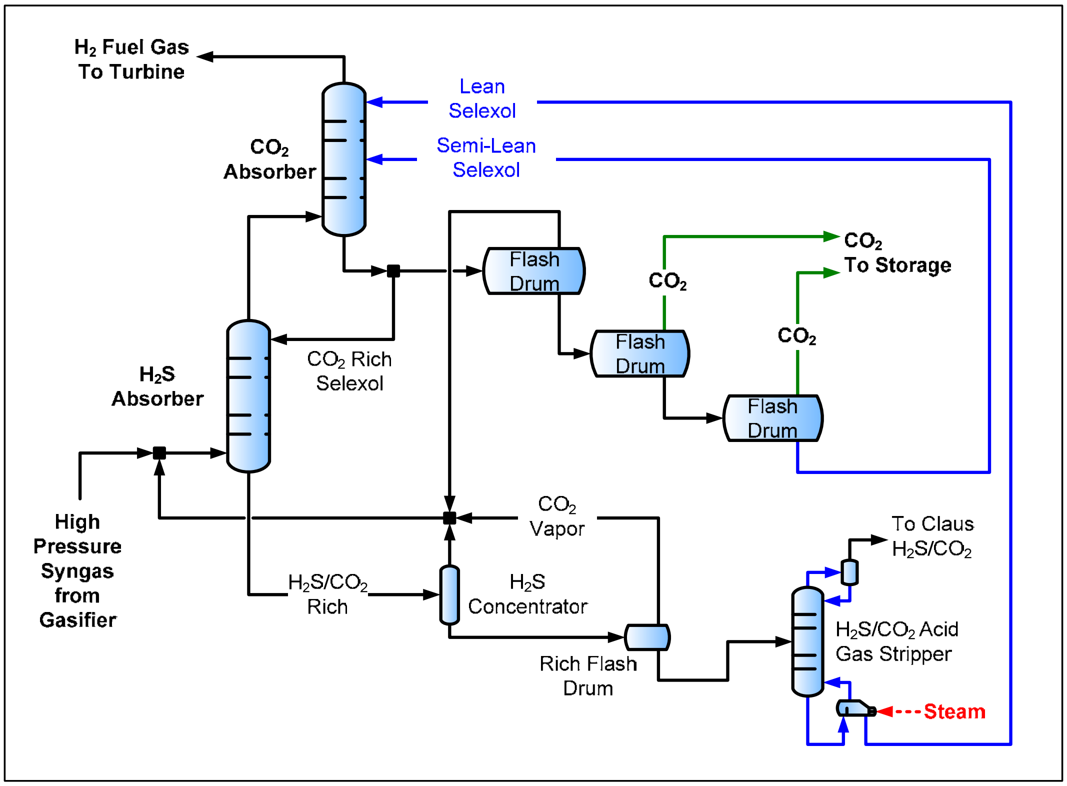


By carefully controlling the amount of O_2, only a portion of the fuel burns to provide the heat necessary to decompose the fuel and produce syngas, a mixture of H_2 and carbon monoxide (CO), along with minor amounts of other gaseous constituents. To enable pre-combustion capture, the syngas is further processed in a water-gas shift (WGS) reactor, which converts CO into CO_2 while producing additional H_2. A physical solvent removal system, such as Selexol™, can then be used to separate the CO_2 from the H_2. Because CO_2 is present at much higher concentrations in syngas (after WGS) than in flue gas, and because the syngas is at higher pressure, CO_2 capture is less expensive for pre-combustion capture than for post-combustion capture. After CO_2 removal, the H_2 can be used as a fuel in a combustion turbine combined cycle to generate electricity (Rubin, 2008; Hamilton, 2009; DOE, 2010a). The advantages of this type of system compared with post-combustion capture (described below) are the higher CO_2 concentration (partial pressure) and the lower volume of syngas to be handled, which result in smaller equipment sizes and lower capital costs.

The current state-of-the-art CO_2 capture technologies that could be applied to IGCC systems include the glycol-based, two-stage Selexol™ process, the methanol-based Rectisol® process, the pyrolidone-based Purisol process, and the polypropylene carbonate-based Fluor solvent (IEA, 2008). All employ physical solvents that preferentially absorb CO_2 from the syngas mixture. However, these systems have not yet been built for full-scale IGCC power plants.

Using the two-stage Selexol™ process as an example (Figure A-3), in the first stage, untreated syngas enters the first of two absorbers where H_2S is preferentially removed using CO_2-rich solvent from the CO_2 absorber. The gas exiting the H_2S absorber passes through the second absorber, where CO_2 is removed using both semi-lean and lean solvent streams. The treated syngas exits the absorber and is sent to the combustion turbine. The CO_2-rich solvent exits the CO_2 absorber, and a portion is sent to the H_2S absorber, while the remainder is sent to a series of flash drums for regeneration. The CO_2 product stream is obtained from the flash drums, and the semi-lean solvent is returned to the CO_2 absorber. The H_2S/CO_2-rich solvent exiting the H_2S absorber is sent to the acid gas stripper, where the absorbed gases are released using a steam heated reboiler. The acid gas from the stripper is sent to a Claus plant to produce elemental sulfur for commercial use, and the lean solvent exiting the stripper is returned to the CO_2 absorber (UOP, 2009).

Figure A-3. Schematic Diagram of the Pre-Combustion Selexol™ CO_2 Capture Process



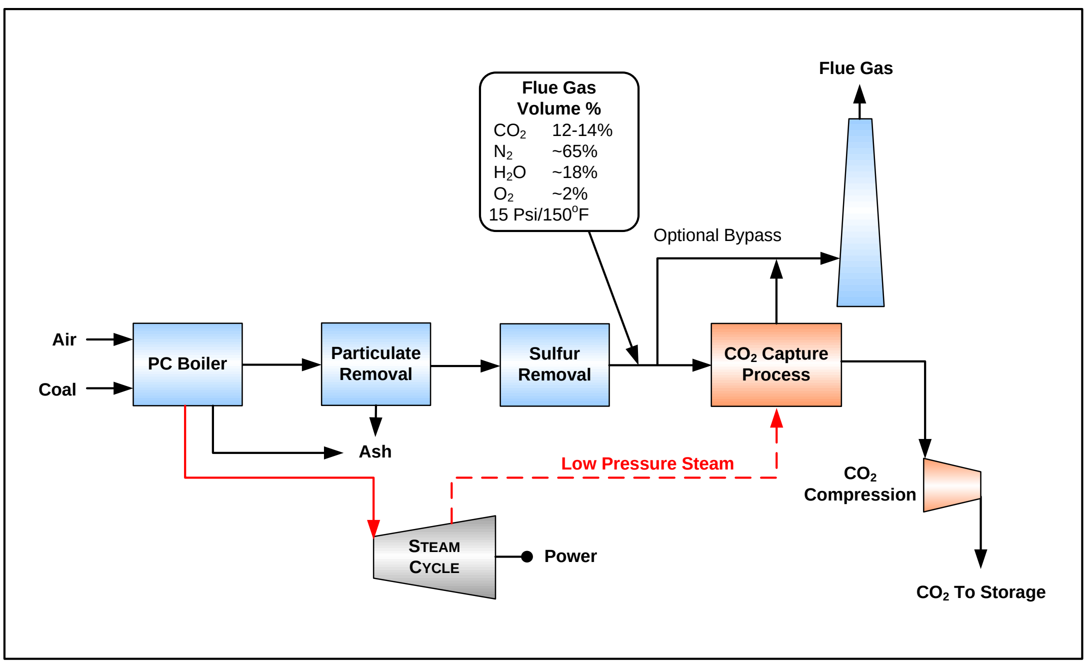
The advantage of physical solvents is that less energy is required in the solvent regeneration step, which involves a temperature increase and/or pressure reduction, leading to an energy penalty of about 20 percent (versus 30 percent energy penalty for chemical solvents used for post-combustion CO_2 capture). Furthermore, although the cost of electricity (COE) for a base IGCC power plant is higher than that for a coal-fired plant, the high thermodynamic driving force for CO_2 capture and reduced CO_2 compression demands at IGCC facilities leads to an increase in COE of less than 40 percent using Selexol™ technology, compared with nearly 80 percent for a conventional coal-fired power plant equipped with an amine scrubber for CO_2 control (as described below) (DOE, 2010a).

A.1.2 Post-Combustion CO_2 Capture

Post-combustion CO_2 capture refers to removal of CO_2 from combustion flue gas prior to discharge to the atmosphere, as shown in Figure A-4 (Herzog, 2009). In a typical coal-fired power plant, fuel is burned with air in a boiler to produce steam that drives a turbine/generator to produce electricity (Bohm, 2006). Flue gas from the boiler consists mostly of N_2 and CO_2. Separating CO_2 from this flue gas is challenging for several reasons:

- a high volume of gas must be treated
  - about 2 million cubic feet per minute for a 500 MWe size plant
- CO_2 is dilute requiring chemical solvents for extraction
  - 12 to 14 volume percent in coal-fired systems
  - 6 to 8 volume percent in gas-fired turbines
- flue gas is at low pressure
  - 15 to 25 pounds per square inch absolute [psia]
- flue gas contains trace impurities that can degrade the CO_2 capture materials (e.g., solvent);
  - particulate matter [PM]
  - sulfur oxides [SO_x]
  - nitrogen oxides [NO_x], etc.

Figure A-4. Post-Combustion CO_2 Capture for a Pulverized Coal Power Plant

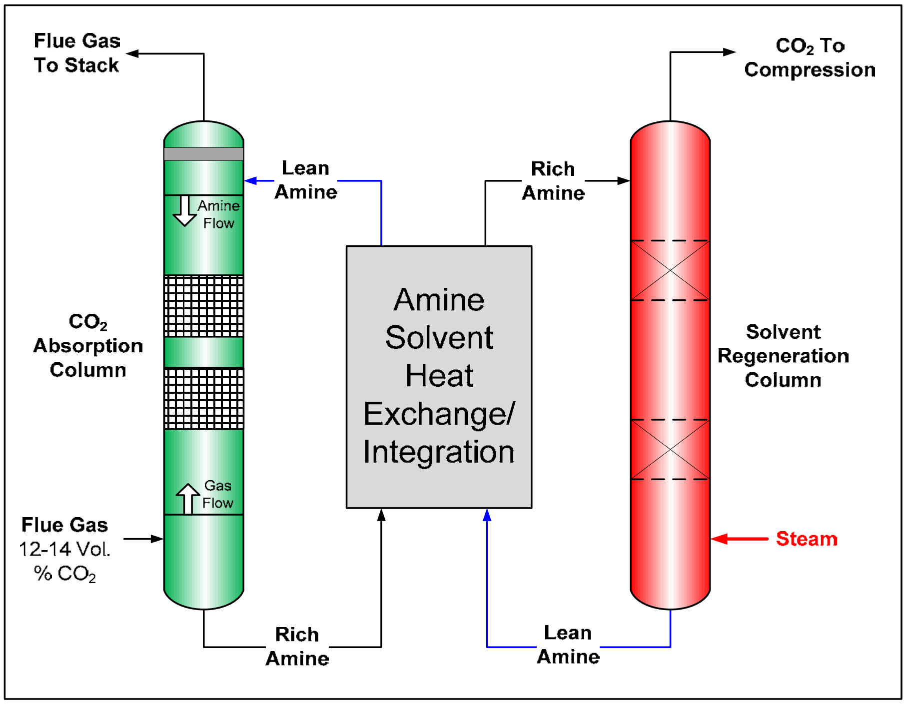


Post-combustion CO_2 capture offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be retrofitted to existing plants and can be tuned for various levels of CO_2 capture (optional bypass shown in Figure A-4), which may accelerate market acceptance. Although post-combustion capture technologies would typically be applied to conventional coal-fired power plants, they can also be applied to the combustion flue gas from IGCC power plants, natural gas combined cycle (NGCC) power plants, and industrial facilities that combust fossil fuels. Currently, several solvent-based capture processes are commercially available, but they have not yet been demonstrated at the scale necessary to help achieve GHG reduction targets. Many projects are in the planning stages for demonstration scale-up including, the Alstom chilled ammonia process and several amine-based processes (e.g., Fluor [Econamine], ABB/Lummus, Mitsubishi Heavy Industries [MHI], HTC Purenergy, Aker Clean Carbon, Cansolv, et al.) (Herzog et al., 2009). In addition, a wide variety of processes are at varying stages of development employing solvents, sorbents, and membranes (EPRI, 2008; Ciferno et al., 2009).

As noted above, amine scrubbing represents a post-combustion capture technology that is currently available, but they have not yet been demonstrated at the scale necessary to help achieve GHG reduction targets. Amines chemically react with CO_2 via reversible reactions to form water-soluble compounds. Despite the low CO_2 partial pressure in combustion flue gas, amines are capable of achieving high levels of CO_2 capture due to fast kinetics and strong chemical reactions. However, the absorption capacity for commercially available amines is chemically limited, requiring two molecules of amine for each molecule of CO_2. In addition, usable amine solution concentrations are typically limited by viscosity and corrosion. Therefore, current amine systems are only between 20 and 30 percent amine with the remaining being water. Although the water present in the solution helps control the solvent temperature during absorption, which is an exothermic reaction, the water also requires significant amounts of sensible heating and stripping energy upon CO_2 regeneration. Not every amine system is the same, and various vendors offer different designs. In general, depending on the amount of heat integration, anywhere from 1,550 to greater than 3,000 British thermal units (Btu) per pound of CO_2 in the form of low pressure steam (approximately 45 psia) is required to regenerate the solvent to produce a concentrated CO_2 stream at a pressure of approximately 25 psia (Herzog, 2009).

An amine-based post-combustion capture process is depicted in Figure A-5.

Figure A-5. Schematic Diagram of Amine-based CO_2 Capture Process



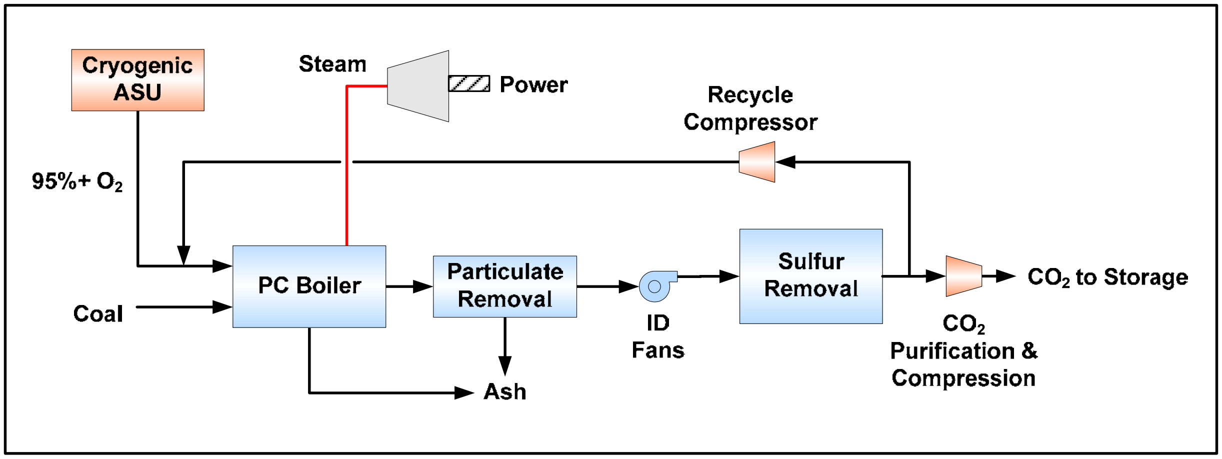
After conventional air pollutant cleanup (SO_x, NO_x, PM), the combustion flue gas enters an absorber reactor and flows counter-currently to a CO_2-lean solvent where CO_2 is absorbed into, and chemically reacts with the amine solution. The treated flue gas (mostly N_2) is discharged to the atmosphere, and the CO_2-rich amine solution is pumped to a solvent regeneration column where the CO_2-rich solution is heated in order to reverse the chemical reactions between the CO_2 and amine solvent. Steam extracted from the turbine cycle, provides the heat for regeneration of the amine solvent in the solvent regeneration column. Consequently, CO_2 is released, producing a concentrated stream that exits the regeneration column and is then cooled and dehumidified in preparation for compression, transport, and storage. From the solvent regeneration column, the CO_2-lean solution is cooled and returned to the absorber for reuse (Herzog, 2009).

Installing the current state-of-the-art amine post-combustion CO_2 capture technology on new conventional subcritical (SubC), supercritical (SC), and ultra-supercritical (USC) coal-fired power plants would increase the levelized cost of electricity (LCOE) by about 80 percent. Further, the large quantity of energy required to regenerate the amine solvent and compress the CO_2 to pipeline conditions would result in about a 30 percent energy penalty (DOE, 2010a).

A.1.3 Oxy-Combustion

Oxy-combustion systems for CO_2 capture rely on combusting coal with relatively pure oxygen diluted with recycled CO_2 or CO_2/steam mixtures, as shown in Figure A-6 (Herzog, 2009). The primary products of combustion are water and CO_2, with the CO_2 separated by condensing the water and removing any other gas constituents that infiltrated the combustion system.

Figure A-6. Pulverized Coal Power Plant with Oxy-Combustion CO_2 Capture



Oxy-combustion overcomes the technical challenge of low CO_2 partial pressure normally encountered in conventional coal combustion flue gas by producing a highly concentrated CO_2 stream (~60 percent), which is separated from water vapor by condensing the water through cooling and compression. An additional purification stage for the highly concentrated CO_2 flue gas may be necessary to produce a CO_2 stream that meets transportation and storage requirements. This purification step should have significantly less cost than a conventional post-combustion capture system, due to the high CO_2 concentration and reduced flue gas volume (Herzog, 2009).

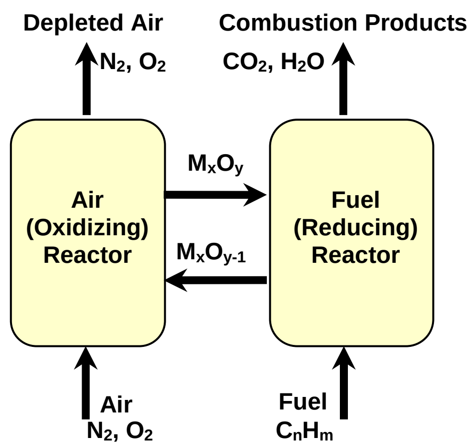
However, the appeal of oxy-combustion is tempered by a few key challenges, namely the capital cost and energy consumption for a cryogenic air separation unit (ASU), boiler air infiltration that dilutes the flue gas with N_2, and excess O_2 contained in the concentrated CO_2 stream. Flue gas recycle (~70 to 80 percent) is also necessary to approximate the combustion characteristics of air, since currently available boiler materials cannot withstand the high temperatures resulting from coal combustion in pure O_2. Consequently, the economic benefit of oxy-combustion compared to amine-based scrubbing systems is limited. Construction of a new supercritical oxy-combustion coal-fired power plant equipped with a commercially available cryogenic ASU would increase the COE by about 60 percent and have a 25 percent energy penalty compared with a new supercritical air-fired, coal-based power plant without CO_2 capture (DOE, 2010a; DOE, 2010b).

A.1.3.1 Chemical Looping Combustion

Chemical looping combustion (CLC) is an advanced coal oxy-combustion technology that involves the use of a metal oxide or other compound as an O_2 carrier to transfer O_2 from the combustion air to the fuel, avoiding direct contact between fuel and combustion air (Figure

A-7). Subsequently, the products from combustion (CO_2 and H_2O) will be kept separate from the rest of the flue gases. Chemical looping splits combustion into separate oxidation and reduction reactions. In one potential configuration, chemical looping is carried out in two fluidized beds. The metal oxide (e.g., iron, nickel, copper, or manganese) releases the O_2 in a reducing atmosphere and the O_2 reacts with the fuel. The metal is then recycled back to the oxidation chamber where the metal oxide is regenerated by contact with air. The advantage of using the CLC process is that no separate ASU is required and CO_2 separation takes place during combustion (NETL, 2009a).

Figure A-7. Chemical Looping Combustion



A related area of research is chemical looping gasification (CLG). In this system, two or three solid particle loops are used to provide the O_2 for gasification and to capture CO_2. A loop, similar to that of CLC, is used to gasify the coal and produce syngas (H_2 and CO). A second solid loop is used in a WGS reactor. In this reactor, steam reacts with CO and converts it to H_2 and CO_2. The circulating solid absorbs the CO_2, thereby providing a greater driving force for the WGS reaction. The CO_2 is then released in a calcination step that produces nearly pure CO_2 for further compression and storage.

A.2 Technical Challenges to CO_2 Capture for Coal-Based Power Generation

As discussed above, in their current state of development, CO_2 removal technologies are not ready for implementation on coal-based power plants for three primary reasons:

1) they have not been demonstrated at the larger scale necessary for power plant application,
2) the energy penalty associated with CO_2 capture would significantly decrease power generating capacity, and

3) if successfully scaled up, they would not be cost effective at their current level of process development (Kuuskraa, 2007).

Other technical challenges associated with the application of these CO_2 capture technologies to coal-based power plants include high capture and compression auxiliary power loads, capture process energy integration with existing power system, impacts of flue gas contaminants (NO_x, SO_x, PM) on CO_2 capture system, increased water consumption and cost effective O_2 supply for oxy-combustion systems (Table A-3). The following is a brief summary of a few of the more significant technical challenges.

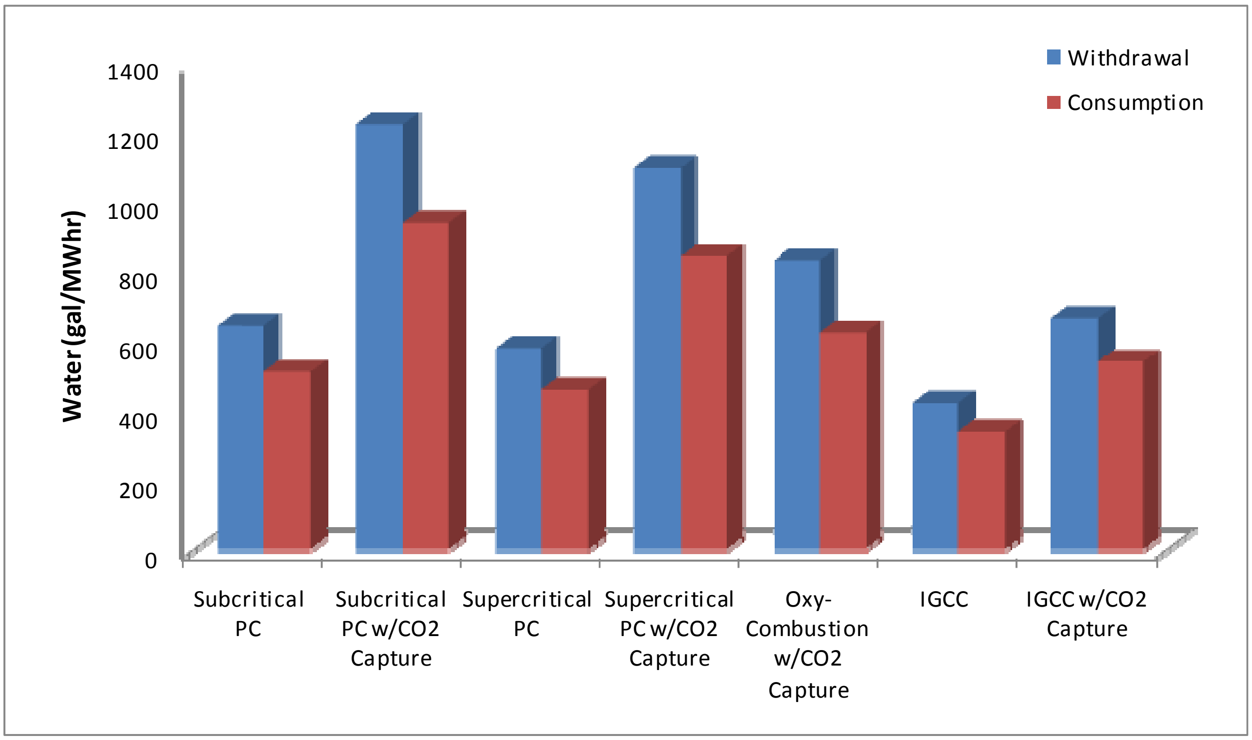
Table A-3. Key Technical Challenges for CO_2 Capture

Parameter	Technical Challenge
Scale-Up	While industrial-scale CO_2 separation processes are now commercially available, they have not been deployed at the scale required for large power plant applications and consequently, their use could significantly increase electricity production costs.
Cost-Effectiveness	Recent studies conducted by NETL show that current technologies are expensive and energy-intensive, which seriously degrade the overall efficiency of both new and existing coal-fired power plants. For example, installing the current state-of-the-art post-combustion CO_2 capture technology – chemical absorption with an aqueous monoethanolamine (MEA) solution – is estimated to increase the levelized COE by about 75 to 80 percent.
Auxiliary Power	A significant amount of auxiliary power is required to operate currently available CO_2 capture technologies. The auxiliary power decreases the net electrical generation of the power plant.
Energy Efficiency	The large quantity of energy required to regenerate the solvent in commercially available CO_2 capture technologies (~1,550 to 3,000 British thermal units [Btu] per pound of CO_2 removed) would significantly reduce the total power plant output.
Energy Integration	The energy required to regenerate the solvent in commercially available CO_2 capture technologies would be provided by steam extraction from the power plant. This activity requires careful integration of the power plant steam cycle to the CO_2 capture technology.
Flue Gas Contaminants	Constituents in the flue gas, particularly sulfur, can contaminate CO_2 capture technologies, leading to increased operational expenses.
Water Use	A significant amount of water use is required for CO_2 capture and compression cooling.
CO_2 Compression	To enable storage, significant power is required to compress the captured CO_2 to typical pipeline levels (1,500 to 2,200 psia depending on storage scheme and location). Reducing this power requirement is essential to improving overall plant efficiency and facilitating CO_2 storage at both existing and future power plants.
Oxygen Supply	An oxy-combustion power plant requires a supply of high-purity oxygen. Currently available technology – cryogenic air separation unit (ASU) – is not considered to be cost effective.

A.2.1 CO_2 Capture Impacts on Water Use

CO_2 capture typically results in the consumption of large quantities of water due to the cooling water requirements of capture and compression (Ciferno et al., 2010). As part of recent DOE/NETL studies, subcritical PC, supercritical PC, oxy-combustion, and IGCC configurations, both with and without capture, were evaluated for a variety of factors including water withdrawal (water removed from a surface or groundwater source) and consumption (water not returned to the source) (DOE, 2010a; DOE, 2010b). The evaluations indicate that there will be a significant increase in overall water use by the PC plants, with a more modest increase for IGCC plants, as shown in Figure A-8. A subsequent study has evaluated five different scenarios for future freshwater withdrawal and consumption requirements for the U.S. thermoelectric generation sector using the Annual Energy Outlook (AEO) 2009 projections for capacity additions and retirements (EIA, 2009). Results from this study indicate that the addition of CCS will increase water withdrawal by five to seven percent by 2030, but consumption will increase by 88 to 100 percent over the same time period (DOE, 2009; DOE/NETL, 2009)

Figure A-8. Relative Water Use for New PC and IGCC Plants With and Without CO_2 Capture

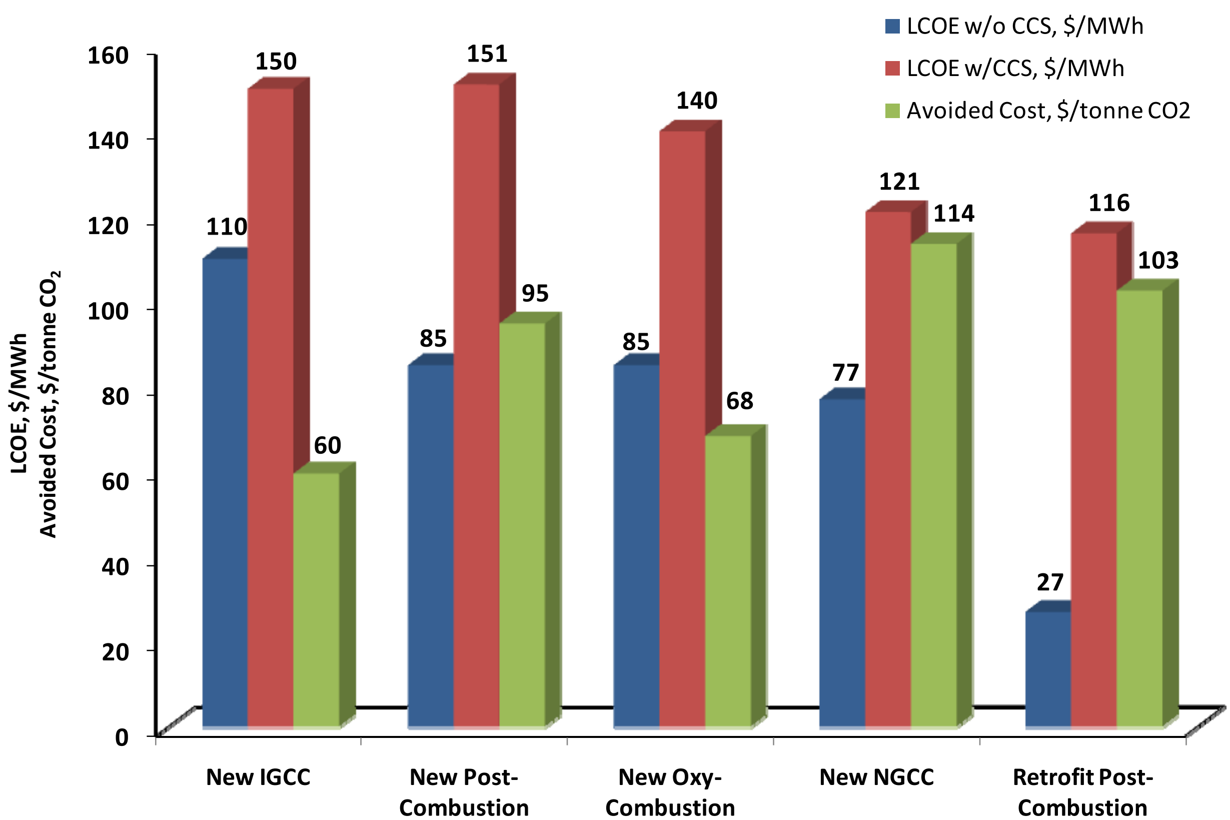


Source: (DOE/NETL, 2009)

A.2.2 CO_2 Capture Impacts on Cost and Performance

As indicated above, technologies exist that will allow for the capture of CO_2 generated during the production of electricity. However, there are significant costs and energy penalties associated with the application of those technologies in their current state of development. Analyses indicate that for a nominal 550 MWe net output power plant, addition of CO_2 capture technology increases the capital cost of a new IGCC facility by $400 million and results in an energy penalty of 20 percent. For post-combustion and oxy-combustion capture, the increases in capital costs are $900 million and $700 million respectively, and the energy penalty would be 30 and 25 percent. For a natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture. The costs associated with CO_2 capture in terms of increases in the LCOE or cost per tonne of CO_2 avoided are shown in Figure A-9. The LCOE ranges from $116/MWh to $151/MWh, depending upon the type of facility and whether the application is for a new plant or a retrofit of an existing plant. This compares to an LCOE of $85/MWh for a new supercritical PC plant and a $27/MWh LCOE for the existing fleet of power plants. In terms of costs per tonne of CO_2 avoided, values range from $60/tonne to $114/tonne.

Figure A-9. Comparison of Levelized Cost of Electricity for Different Types and Configurations of Power Plants



Source: (DOE, 2010a; DOE, 2010b)

A.3 Cost Estimating Methodology

A summary of the costing assumptions behind the levelized cost of electricity (LCOE) calculation referred to throughout the Task Force CCS report is contained here. A fully documented methodology can be found in DOE (2010a) and DOE (2010b).

<u>Capital Costs</u>

All capital costs are presented as "overnight costs" expressed in December 2009 dollars. Capital costs are presented at the total plant cost (TPC) level. TPC includes:

- equipment (complete with initial chemical and catalyst loadings),
- materials,
- labor (direct and indirect),
- engineering and construction management, and
- contingencies (process and project).

<u>Owner's Costs</u>
Owner's costs were subsequently calculated and added to the TPC. The result is defined as total overnight cost (TOC) and is the capital expenditure used in the calculation of LCOE. The owner's costs included in the TOC cost estimate are shown in Table A-4.

Table A-4. Owner's Costs Included in TOC

Owner's Cost	Comprised of
Preproduction Costs	• 6 months O&M, and administrative & support labor • 1 month maintenance materials @ 100% Capacity Factor (CF) • 1 month non-fuel consumables @ 100% CF • 1 month of waste disposal costs @ 100% CF • 25% of one month's fuel cost @ 100% CF • 2% of TPC
Inventory Capital	• 60 day supply of fuel and consumables @100% CF • 0.5% of TPC (spare parts)
Land	• $3,000/acre (300 acres for greenfield IGCC and PC, and 100 acres for NGCC)
Financing Costs	• 2.7% of TPC
Other Owner's Costs	• 15% of TPC
Initial Cost for Catalyst and Chemicals	• All initial fills not included in bare erected cost (BEC)
Prepaid Royalties	• Not included in owner's costs (included with BEC)
Allowance for Funds Used During Construction (AFUDC) and Escalation	• Varies based on levelization period and financing scenario • 33-yr IOU high risk: Total As-Spent Capital Cost (TASC) = TOC * 1.078 • 33-yr IOU low risk: TASC = TOC * 1.075 • 35-yr IOU high risk: TASC = TOC * 1.140 • 35-yr IOU low risk: TASC = TOC * 1.134

The category labeled "Other Owner's Costs" includes the following:

- preliminary feasibility studies, including a Front-End Engineering Design (FEED) study;

- economic development (costs for incentivizing local collaboration and support);
- construction and/or improvement of roads and/or railroad spurs outside of site boundary;
- legal fees;
- permitting costs;
- owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors); and
- owner's contingency: sometimes called "management reserve", these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of those for a 5 day, 10 hours per day work schedule.

Cost items excluded from "Other Owner's Costs" include:

- EPC Risk Premiums,
- transmission interconnection,
- taxes on capital costs, and
- unusual site improvements.

<u>Operations and Maintenance</u>
The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- operating labor,
- maintenance – material and labor,
- administrative and support labor,
- consumables,
- fuel,
- waste disposal, and
- co-product or by-product credit (that is, a negative cost for any by-products sold).

<u>Thirty-Year, Current-Dollar LCOE</u>
The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit is a current-dollar, 30-year LCOE. The effective levelization period is the sum of the operational levelization period (30 years for all plants) and the capital expenditure levelization period (assumed to be 3 years for NGCC plants and 5 years for IGCC and PC plants). The sum results in an effective levelization period of 33 years for the NGCC cases and 35 years for the IGCC

and PC cases. The LCOE is expressed in mills/kWh (numerically equivalent to $/MWh). The current-dollar, 30-year LCOE was calculated using a simplified equation derived from the NETL PSFM (Power Systems Financial Model Version 5.0, 2006).

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TOC) + (LF)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where:

$LCOE_P$ = levelized cost of electricity over P years, $/MWh

P = levelization period (e.g., 10, 20 or 30 years)

CCF_P = capital charge factor for a levelization period of P years

TOC = total overnight cost, $

LF = levelization factor (a single levelization factor is used in each case because a single escalation rate is used for all costs)

OC_{Fn} = category n fixed operating cost for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

CF = plant capacity factor

OC_{Vn} = category n variable operating cost at 100 percent CF for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent CF

All costs are expressed in December 2009 year dollars, and the resulting LCOE is expressed in mixed year dollars.

Although their useful life is usually well in excess of 30 years, 33-year (NGCC) and 35-year (IGCC and PC) levelization periods (including the variable capital expenditure levelization periods as defined above) are the levelization periods used in this study.

The technologies modeled in this study were divided into one of two categories for calculating LCOE: Investor Owned Utility (IOU) high risk and IOU low risk. All IGCC cases as well as PC and NGCC cases with CO_2 capture are considered high risk. The non-capture PC and NGCC cases are considered low risk. The resulting CCF and LFs are shown in Table A-5.

Table A-5. Economic Parameters for LCOE Calculation

	High Risk 5 year construction	**Low Risk** 5 year construction	**High Risk** 3 year construction	**Low Risk** 3 year construction
Capital Charge Factor	0.1773	0.1691	0.1567	0.1502
Levelization Factor	1.42689	1.45104	1.41094	1.43262

The economic assumptions used to derive the CCFs are shown in Table A-6. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the CCFs and LFs in this study are shown in Table A-7.

Table A-6. Parameter Assumptions for Capital Charge Factors

Parameter	Value
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
FINANCING TERMS	
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Construction (nominal annual rate)	3.6%[1]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	3-Year Period: 10%, 60%, 30% 5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
INFLATION	
LCOE, O&M, Fuel Escalation (nominal annual	3.0%[2] COE, O&M, Fuel

[1] A nominal average annual rate of 3.6% is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

[2] An average annual inflation rate of 3.0% is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power

Parameter	Value
rate) Escalation rates must be the same for LCOE approximation to be valid	

Table A-7. Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
High Risk				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

A.4 Planned Demonstrations of CO_2 Capture Technologies

DOE/NETL is currently engaged in two major CCS demonstration programs.

The Clean Coal Power Initiative (CCPI) is an innovative technology demonstration program that fosters more efficient clean coal technologies for use in new and existing coal-based power plants. The intent of CCPI is to accelerate technology adoption and thus rapidly move promising new concepts to a point where private-sector decisions on deployment can be made.

CCPI is currently pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects (Table A-8). The pre-combustion projects involve CO_2 capture from IGCC power plants. The generating capacities at the demonstration facilities range from 257 to 582 MW. The capture efficiencies range from 67 percent to 90 percent, and total CO_2 captured ranges from 1.8 to 2.7 million tonnes per year. The demonstrations will be initiated between 2014 and 2016, and the projects will run for 2-3 years. The post-combustion projects will capture CO_2 from pulverized coal (PC) plant slipstreams representing the equivalent of 60 to 235 MW of power production. Each will capture 90 percent of CO_2 emissions with total capture of 0.4 to 1.5 million tonnes per year.

Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

Similar to the CCPI projects, the FutureGen project will demonstrate carbon capture from a 200 MW advanced oxy-combustion unit in Meredosia, Illinois, integrated with CO_2 storage in Mattoon, Illinois. FutureGen aims to capture and store at least one million tonnes of CO_2 per year.

Table A-8 Capture Projects Being Conducted as part of CCPI and Future Gen

Performer	Location	Capture Technology	Capture Rate tonnes/year	Start Date
Pre-Combustion Capture				
Summit Texas Clean Energy	Odessa, TX	Selexol	2,700,000	2014
Southern Company	Kemper County, MS	Selexol	1,800,000	2014
Hydrogen Energy California	Kern County, CA	Rectisol	1,800,000	2016
Post –Combustion Capture				
Basin Electric	Beulah, ND	Amine	450,000 - 1,360,000	2014
NRG Energy	Thompsons, TX	Amine	400,000	2015
American Electric Power	New Haven, WV	Chilled Ammonia	1,500,000	2015
Oxy-Combustion				
FutureGen	Meredosia and Mattoon, Il	Oxy-Combustion	1,000,000	2015

In addition to the demonstrations under the CCPI and FutureGen programs, additional CO_2 capture demonstration projects are being conducted under the Industrial Carbon Capture and Storage (ICCS) program (Table A-9). Several of the ICCS projects are pursuing capture technologies that are similar to those that are being demonstrated for power plants. These projects are of similar magnitude to the CCPI capture demonstrations (90 percent capture, ~1-4 million tonnes/year captured). Eleven projects were initially selected for the ICCS program. In June 2010 there was a down-selection of three projects that will move forward to full demonstrations. These include the Leucadia Energy Lake Charles project, the Archer Daniels Midland project, and the Air Products project.

Table A-9. Projects Selected Under the Industrial Carbon Capture and Storage Initiative

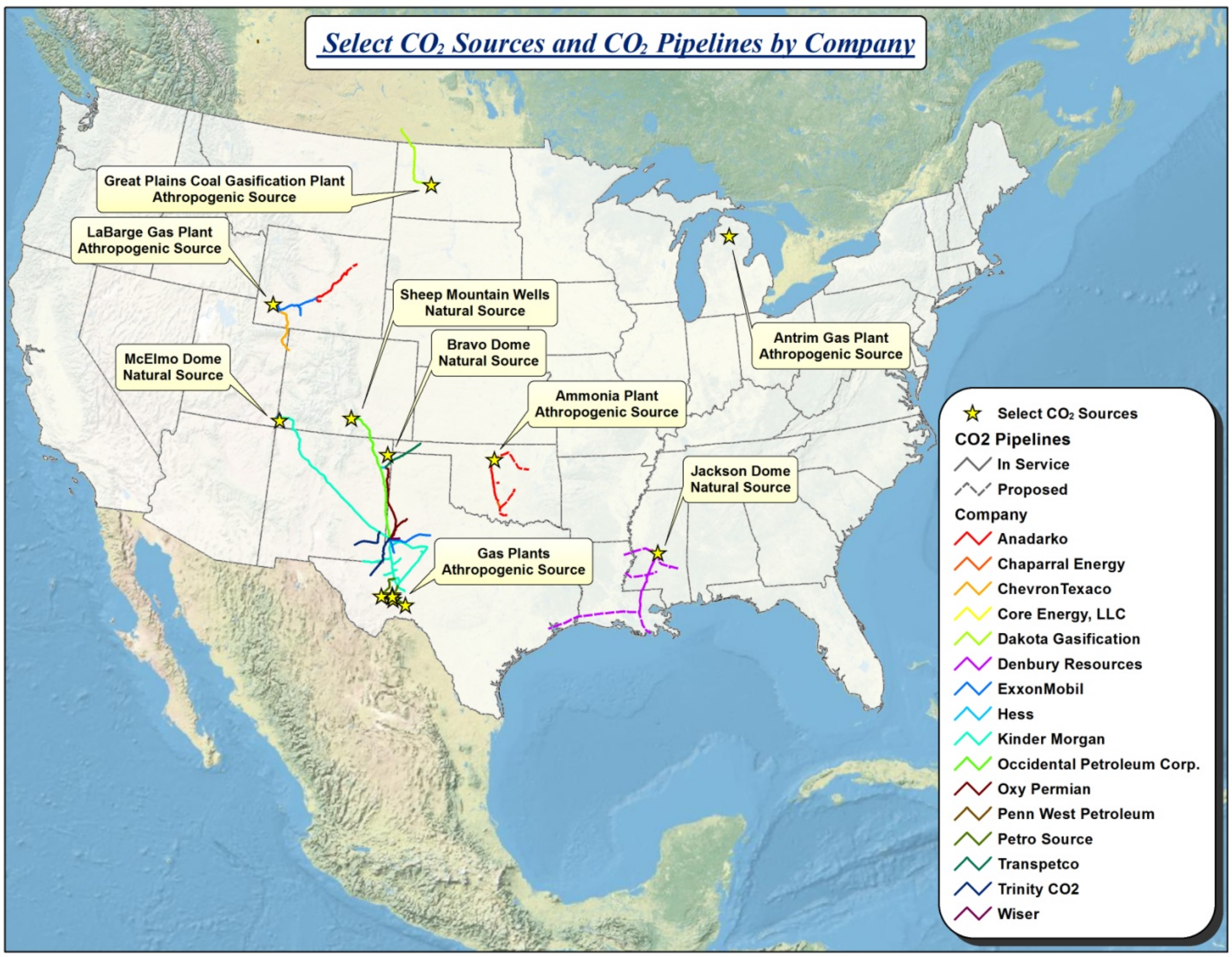
Performer	Location	Capture Technology	Product	Capture Rate Tonnes/year	Start Date
Leucadia Energy Lake Charles	Lake Charles, LA	Rectisol	Methanol	4,000,000	2014
Archer Daniels Midland	Decatur, IL	Amine	Power, Ethanol	900,000	2014
Air Products	Port Arthur, TX	Amine	Hydrogen	900,000	2013

Appendix B. CO_2 Pipeline Transport – State of Technology Development: Supplementary Material

B.1 Existing Pipeline Networks in the United States

There are several CO_2 pipeline systems in the United States that were built largely to transport CO_2 from natural sources to consuming oil fields for EOR. CO_2 sources for these systems include natural deposits, natural gas processing plants, and other high-purity industrial vents. The longest existing pipeline system, the Cortez Pipeline, delivers CO_2 over a distance of 500 miles in the Permian basin of Texas, Colorado, and New Mexico (Parfomak and Folger, 2007). Other systems transport CO_2 along the Gulf Coast (Mississippi and Louisiana), through Colorado and Wyoming, from North Dakota into Canada, and in Northern Michigan. In addition, there are many smaller CO_2 pipelines connecting sources with specific customers. Figure B-1 and Table B-1 summarize the CO_2 pipelines in the United States.

Figure B-1. Existing and Planned CO_2 Pipelines in the United States with Sources



Source: NETL using data from Energy Velocity Database (2010).

Table B-1. CO_2 Pipeline Summary

Company	In Service Pipeline System Length (Miles)	Proposed Pipeline System Length (Miles)	Total Pipeline System Length (Miles)	Number of State Border Crossings
Anadarko	261.6	302.0	563.6	0
Chaparral Energy	22.2	0.0	22.2	0
ChevronTexaco	147.6	0.0	147.6	2
Core Energy, LLC	10.3	0.0	10.3	0
Dakota Gasification	215.6	0.0	215.6	1 (U.S. /Canada)
Denbury Resources	202.6	599.3	801.9	3
ExxonMobil	362.7	0.0	362.7	1
Hess	43.4	0.0	43.4	0
Kinder Morgan	1,108.5	0.0	1,108.5	3
Occidental Petroleum Corp.	390.4	0.0	390.4	1
Oxy Permian	293.5	0.0	293.5	1
Penn West Petroleum	7.0	0.0	7.0	0
Petro Source	147.1	0.0	147.1	0
Transpetco	120.6	0.0	120.6	2
Trinity CO_2	223.5	0.0	223.5	4
Wiser	26.7	0.0	26.7	0

Source: NETL Generated from Energy Velocity Database, April 2010.

B.2 Pipeline Design

The primary design considerations for CO_2 pipelines are similar to those of natural gas and hazardous liquid pipelines, such as operating pressure and temperature, protection from outside forces, and control room management using Supervisory Control and Data Acquisition (SCADA) systems. CO_2 poses a number of specific threats that can be mitigated in the pipeline design stage. One major threat to the integrity of CO_2 systems is the generation of carbonic acid from ambient moisture in the pipeline. The following are some of the design considerations germane to reducing integrity risks and consequence of failure:

- CO_2 composition, impurities, and phase behavior;

- Line pipe material selection and fracture control;
- Valve, seal, elastomer, and pumping material selection;
- Valve spacing; and
- Leak detection.

Pipeline operators must follow specific requirements of the DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) listed in its Hazardous Liquid Pipeline Safety Regulations (49 C.F.R. Part 195) that address many of these design considerations. Most of the regulations are identical for transportation of hazardous liquids and CO_2, with a few notable differences. For example, components for CO_2 pipelines must be "made of materials that are suitable" for low temperatures that may be associated with "rapid pressure reduction or during the initial fill of the line." Also, fracture propagation must be mitigated against when designing a CO_2 pipeline. Lastly, valve materials must be compatible with CO_2. The presence of impurities lowers the saturation pressure of the gases which affect the susceptibility of pipeline materials to arrest fractures. This can be mitigated by increasing the thickness of the steel and the use of mechanical crack arrestors (Cosham and Eiber, 2008). These requirements, along with industry design standards from the American Society of Mechanical Engineers (ASME) and the American Petroleum Institute (API), which are incorporated into 49 C.F.R. Part 195 by reference, are in place to reduce pipeline risks from CO_2 pipeline systems.

B.3 Pipeline Construction

Construction requirements and standards are virtually identical for CO_2 and gas transmission and hazardous liquids pipelines, and are not considered a barrier to CCS deployment. One major goal is to avoid damage to system components during transportation or during the actual construction activity. These construction requirements and standards are in place to protect pipelines from damage and to maximize the integrity of the system over its operating lifespan.

There are construction-related concerns that, if left unresolved, could have a negative impact on the long- and short-term integrity of the pipeline. Resolution can involve procedure revisions, additional personnel training, modification to construction practices, or physical repairs to the pipeline, pipeline coating, or auxiliary pipeline features. PHMSA inspections help to ensure that these issues are corrected prior to the pipeline being buried and operated. Hydrostatic pressure tests and inline inspection (ILI) tool runs are also procedures that help assess pipeline integrity.[3]

B.4 Pipeline Operation and Safety

There are a number of operational challenges for liquid CO_2 pipelines. Maintaining the supercritical phase, as well as controlling impurities and moisture content, are paramount for the safe operation of these systems. CO_2 pipelines generally operate above 2,000 pounds-force per square inch gauge (psig) in order to maintain the product in the liquid phase. Impurities directly affect the phase behavior, and if not controlled adequately can lead to pump cavitation

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[3] See http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/maop_determination.pdf.

and localized reduction in pressure. Excessive water in the pipeline may lead to carbonic acid corrosion and the formation of ice plugs, and must be strictly avoided. In addition, impurities directly affect the arrest of propagating fractures, and must be considered in design.

The risk assessment during the design stage may lead to the consideration of shorter distances between sectionalizing (block) valves, which shut off flow on either side of a detected leak in the pipeline. The potential consequence of shorter spacing is the creation of more possible leak paths from the valves themselves. The goal of SCADA systems and tighter valve spacing is to detect pressure reductions from ruptures so that the volumes released are minimized. Monitoring of key parameters, including pressure, temperature, and flow rate, allow for timely intervention and smaller releases. In addition, they reduce the likelihood of ice plugs around valves, which could impede safety operations.

Traditional leak detection systems used for natural gas transmission and hazardous liquids pipelines can be effective, but only after tailoring them to CO_2 pipelines. Gaseous CO_2 must be odorized using hydrocarbon-based odorants. The fading of odorant due to changing concentrations of impurities creates challenges for odorant detection using traditional leak detection technologies. Airborne leak monitoring can be useful in identifying leaks, since PHMSA regulations require several right-of-way surveys per year. In addition, liquid CO_2 system leakage creates detectable localized reductions in the temperature around the leak that can be detected using thermal imaging.

The regulations for hazardous liquids pipeline integrity programs require that all hazardous liquids systems located in High Consequence Areas[4] (HCA) have a baseline pipeline integrity assessment, and be periodically reassessed. The use of ILI technology, or "smart pigging," is a major component of these assessments. CO_2 pipelines can create greater wear on these ILI tools compared with the assessments of other hazardous liquids pipelines, which may lead to higher costs to the operator.

System maintenance and incident response may require occasional blow-down of pipeline contents. For CO_2 pipelines, the blow-down rate must be strictly controlled, and in many cases the contents will be captured. Also, pipeline integrity operations may create hazards. As inspection tools are removed from a CO_2 pipeline, they may entrain liquid CO_2 into components which could break apart forcibly as the CO_2 decompresses.

The CO_2 pipeline safety record, with respect to both the frequency and consequence of failure, is comparable to traditional gas transmission and hazardous liquids pipelines. Given their relatively low mileage, the frequency of failures, and the mainly rural systems, CO_2 pipelines have been less prone to excavation damage, which is the primary cause of failures for other Department of Transportation (DOT) regulated pipelines. The risk profile for CO_2 pipelines is somewhat different than for traditional gas transmission and hazardous liquids pipelines. Special

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[4] HCA are defined as current class 3 and 4 locations; facilities with persons who are mobility-impaired, confined, or hard to evacuate, and places where people gather for recreational and other purposes. For facilities with mobility-impaired, confined, or hard-to-evacuate persons and places where people gather, the corridor of protection from the pipeline is 300 feet, 660 feet or 1000 feet depending on the pipeline's diameter and operating pressure. See http://www.epa.gov/EPA-IMPACT/2002/August/Day-06/i19840.htm.

care must be given to a variety of design, operational, and human safety considerations in order to better compensate for CO_2 system-specific issues. DOT assumed the safety oversight of liquid CO_2 pipelines in 1988 and codified design, operational, and emergency response requirements in 49 C.F.R. Parts 194 and 195. That action, and the strengthening of related integrity management requirements in 2001, is focused on safe and secure liquid CO_2 pipeline operation.

Emergency responders are trained to respond safely to pipeline incidents. Specific training (Hazardous Waste Operations and Emergency Response) is required for both pipeline operator personnel and emergency responders. In addition, 49 C.F.R. Part 194 requires operators to have spill response plans and to hold spill drills in coordination with local officials, and to implement public awareness plans addressing the threats coming from hazardous liquid systems. A partnership between PHMSA and the National Association of State Fire Marshals resulted in the creation of training materials covering the risks associated with transportation of all pipeline commodities, which are available at http://pipeline.mindgrabmedia.com/main.aspx.

Appendix C. CO_2 Storage – State of Technology Development: Supplementary Material

C.1 CO_2 Storage History

CO_2 fields are often found in regions that also host hydrocarbon resources. For example, Bravo Dome (New Mexico), McElmo Dome (Colorado), Escalate Reservoir (Utah), Farnham Reservoir (Utah), Woodside Reservoir (Utah), and LaBarge Dome (Wyoming) are some of the natural CO_2 reservoirs in the Colorado Plateau. Like many natural CO_2 accumulations, most of these deposits were discovered during hydrocarbon exploration. CO_2 from these reservoirs can be as pure as 98 percent. Contaminants often include natural gas and other hydrocarbon compounds.

C.1.1 CO_2 Storage Experience Associated with CO_2 Enhanced Oil Recovery

CO_2-enhanced oil recovery (EOR) and enhanced gas recovery (EGR) technologies are used in oil and gas reservoirs to improve production efficiency. Injection of CO_2 is one of several enhanced recovery (ER) techniques that have successfully been used to boost production efficiency of oil and gas by re-pressurizing the reservoir, and in the case of oil, by also increasing mobility.

CO_2 currently injected for CO_2-EOR in the United States comes from both natural and anthropogenic sources, which provide 79 percent and 21 percent, respectively, of CO_2 supply (NETL, 2008). Historically, CO_2 purchases comprise about 33 to 68 percent of the cost of a CO_2-ER project (EPRI, 1999). For this reason, CO_2 injection volumes are carefully managed at ER sites. CO_2 recovered from production wells during ER is recycled (i.e., separated and re-injected) and, at the conclusion of an ER project, as much CO_2 as possible is recovered and transported to other ER facilities to be used again. However, a certain incidental amount of CO_2 remains underground.

As of 2008, there were 105 CO_2-EOR projects within the United States (Oil and Gas Journal, 2008). The majority (58) of these projects are located in Texas, and the remaining projects are located in Mississippi, Wyoming, Michigan, Oklahoma, New Mexico, Utah, Louisiana, Kansas, and Colorado. CO_2-EOR projects recovered 323,000 barrels of oil per day in 2008, 6.5 percent of total domestic oil production. A total of 6,121 CO_2 injection wells among the 114 projects were used to inject approximately 50 million tonnes of CO_2. Compared with CO_2-EOR, CO_2-EGR remains largely in the development stage (e.g., Oldenburg et al., 2001; NETL, 2008; Oil and Gas Journal, 2008; EIA, 2009).

C.1.1.1 Large-Scale Geologic Storage Projects

Following are brief descriptions of several large-scale operations of engineered storage of CO_2:

The Sleipner project, started in 1996, is the longest-running commercial-scale CO_2 storage project in the world. The Norwegian project injects 98 percent pure CO_2 separated from produced natural gas in order to avoid paying a carbon tax to vent the CO_2 imposed by the Norwegian government. The project injects one million tonnes of CO_2 annually through one horizontal well into the 250m thick Utsira Sand, a high permeability, high porosity sandstone unit roughly 1,100m below the sea surface. The reservoir is sealed with shales, and mudstones and shale baffles (discontinuous shale lenses) are present in the reservoir to further deter upward movement of CO_2. Based on its somewhat unique lithologic properties, the Utsira Sand is considered a good analogue for an optimal storage reservoir.

The Weyburn project is a combined EOR/geologic storage project operated by EnCana in southern Saskatchewan near the North Dakota Border. The project began in 2000 and uses a mix of 29 horizontal and vertical wells to annually inject roughly 1.8 million tonnes of 96 percent pure supercritical CO_2 from a nearby synfuels plant into two adjacent carbonate layers. Successful CO_2-EOR operations at the site have demonstrated the applicability of EOR/GS technology to thin, less-than-ideal formations at moderate depth.

The Snøhvit project in the Barents Sea started operation in 2010. Natural gas produced from the Snøhvit Field contains ~5 vol% CO_2. The CO_2 is removed from the natural gas at the receiving station located at Melkopya, near Hammerfest. The carbon dioxide produced with the gas from the Snøhvit field is sent back near the site of production via pipeline and injected through a dedicated well 2,600 meters beneath the seabed at the edge of the reservoir in the Tubåsen sandstone formation. This formation is located below the producing formations. The project is expected to store approximately 0.7 million tonnes CO_2 each year.

In Salah is a commercial-scale CO_2 storage project located in the Sahara Desert in Southern Algeria. It uses three horizontal wells to annually inject roughly 1.2 million tonnes of supercritical 98 percent pure CO_2 separated from produced natural gas. The reservoir is a 1,800m deep, 21m thick, low-porosity, low-permeability laterally heterogeneous muddy sandstone. Successful utilization of this reservoir relied on measurement-while-drilling techniques, which were able to target higher-quality regions of the formation in real-time as the wells were drilled. This project demonstrated that reservoirs previously thought of as marginal or unusable could successfully store commercial-scale quantities of CO_2.

Other non-commercial scale test projects are underway across the globe. Projects such as Ketzin (Germany), Lacq (France), Otway (Australia), Gorgon (Australia), KB12 (Netherlands), and Nagaoka (Japan) either have already been completed, are underway, or are anticipated to commence injection in the next five years. In total, these and other projects have committed to store an additional eight million tonnes of CO_2 and report on which methods for transport, purification, injection, monitoring, and other parameters were successful in the diverse environments these projects reflect.

C.1.1.2 EPA and DOE Tracking of Geologic Storage Projects

As of May 2010, 56 active storage or integrated capture and storage projects are planned or underway. The active storage projects are located across the nation in 22 States and the Navajo Nation. Eighteen of these States and the Navajo Nation have UIC program primacy for at least one class of injection well (EPA directly implements the program in the other four States). Ten of these States are in the process of developing regulations to address liability and/or property rights.

- 55 percent of the active storage projects are large: they plan to inject over one million tonnes of CO_2 total.

- The RCSP Phase II storage projects that are complete as of 2009 have collectively injected a total of 1,450,290 tonnes of CO_2. This includes 63,790 tonnes injected into saline formations; 1,369,500 tonnes for EOR projects; and 17,700 tonnes into coal.
- Forty-one storage projects have been funded by the U.S. government through cooperative agreements, of which 12 are complete. The total cost of these projects was nearly $8.6 billion (this figure represents a mix of government and participant cost share).
- Over half of the active storage projects (51 percent) are EOR/EGR projects. The remaining are saline (37 percent), EOR/saline (6 percent), and Enhanced Coalbed Methane (ECBM) (6 percent).
- The storage projects involve injecting into several different depositional classes of geologic formations (e.g., basalts, carbonates, clastic rocks, and coal) to assess issues with injectivity, capacity, and containment associated with the varied geology across the U.S.

C.2 CO_2 Storage Capacity

A range of geologic formations is being assessed as potential target formations for injecting and storing CO_2. Target formations with the greatest geologic storage capacity include deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and other formations.

While saline formations clearly offer the greatest potential storage resource and capacity, as noted in the body of the report, many of the first geologic storage projects will likely be in oil and gas reservoirs because these sites have been previously characterized and have existing infrastructure to support injection activities.

Deep saline formations: These formations are sedimentary rock layers that are generally more than 800 meters deep and are saturated with waters or brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS). Deep saline formations are found throughout the United States, and many of these formations may be overlain by laterally extensive, impermeable formations that may restrict upward movement of injected CO_2.

Depleted oil and gas reservoirs: Because many of these reservoirs have trapped liquid and gaseous hydrocarbon resources for millions of years, it is believed that they can also be used to store CO_2. Hydrocarbons are commonly trapped structurally, by faulted, folded, or fractured formations, or stratigraphically, in porous formations bounded by impermeable rock formations. These same trapping mechanisms can effectively store CO_2 for geologic storage in depleted oil and gas reservoirs.

Unmineable coal seams: Currently, ECBM operations exploit the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane, which can then be captured and produced for economic purposes. Studies suggest that for every molecule of methane displaced in ECBM operations, three to thirteen CO_2 molecules are adsorbed. This process effectively "locks" the CO_2 to the coal, where it remains stored.

Capacity estimates are regionally variable, but details are being refined in ongoing efforts (e.g., in both DOE and USGS). In 2008, USGS initiated development of a methodology for estimating the capacity to store CO_2 in geologic formations of the United States. While previous capacity estimates published by DOE/National Energy Technology Laboratory have been broad in scope (i.e., geologic basin-wide), the USGS is focusing on smaller-scale, refined estimates. In 2010, USGS published a proposed, geology-based probabilistic methodology for geologic storage capacity estimation and will undertake a national estimate starting in 2010.[5] Estimated capacities contain uncertainties arising from a number of factors, including geologic (e.g., subsurface heterogeneity and materials properties), hydrologic (e.g., movements of fluids and pressure fronts), and economic (e.g., variability in site-specific constraints and costs).

C.3 Technical Considerations for Geologic Storage

C.3.1 Monitoring, Verification, and Accounting

As noted in the report, monitoring, verification, and accounting (MVA) are important components of managing a geologic storage project and ensuring that the CO_2 plume and associated pressure front are moving through the subsurface as predicted. Baseline monitoring data are necessary to differentiate natural phenomena from signals associated with storage. Data collected during site characterization (such as baseline geochemistry, pre-injection reservoir pressure, etc.) are necessary to ensure that baseline information is available to form the basis for comparison during geologic storage operation and post-injection. For example, the baseline geochemical information will allow the owner or operator and permitting authority to evaluate monitoring data and identify any changes in subsurface geochemistry that may indicate fluid movement. Operational-phase monitoring can demonstrate that a geologic storage project is performing as predicted, or provide warning that unexpected fluid movement has occurred and USDWs may be endangered or other adverse impacts associated with leakage of stored CO_2 may occur. For example, monitoring data can demonstrate that the injectate is confined in the injection zone, identify potential corrosion of well materials and signal needed well construction/mechanical integrity fixes, or identify changes in formation fluid geochemistry (e.g., pH decreases that could cause metals to leach into ground water). Post-injection monitoring can help ensure that there is no USDW endangerment or contamination or other adverse impacts associated with a geologic storage site until the CO_2 plume and pressure front stabilize.

Appropriate monitoring of a geologic storage site can also provide data to maintain the efficiency of the storage operation, minimize costs, improve site modeling, and target needed future corrective action. Robust MVA is also needed to ensure the integrity of CO_2 storage as a mitigation strategy under a carbon-constrained regulatory regime.

Several large projects involve extensive monitoring:

- At the Sleipner project, gravity and seismic surveys have been used to track the migration of the CO_2 plume. Both methods have been able to successfully image the

[5] This report, *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage*, is available at http://energy.usgs.gov/.

plume and verify that the CO_2 is behaving as expected. No leaks have been detected at the site.

- At Weyburn, monitoring using seismic, pressure, and geochemical techniques also indicated that no leaks had taken place, even though more than 1,072 wells dating back to the 1960s were present within Weyburn field. This is an important finding because abandoned wells are thought to be an important potential leakage path for CO_2.
- At In Salah, in additional to standard seismic and geochemical techniques, the project also used satellite monitoring to measure uplift of the earth surface to monitor CO_2 migration within the reservoir. This technology was able to successfully image unexpected developments within the plume due to a previously uncharacterized fracture pattern in the subsurface. Discovery of the new migration pattern led to the detection of a leak at an old monitoring well, which was then permanently sealed. This event confirmed that innovative monitoring techniques are capable of successfully identifying leaks.
- The DOE Regional Carbon Sequestration Partnerships (RCSP) projects also involve testing of monitoring technologies. The results from the small scale field tests are summarized in a best-practices document that will be updated as results emerge from the large-scale field efforts.[6]

Recent experience involving injection of municipal wastewater via Class I municipal disposal wells in Florida offers an insight into the importance of monitoring at geologic storage sites. Ground water monitoring data detected upward fluid movement of some of the injected wastewater, which had a lower density (lower TDS) than the native formation fluids through preferential pathways, such as fractures in karstic rock formations. While this situation identified the need for more rigorous site characterization, which was addressed in a rulemaking (70 Fed. Reg. 70513, November 22, 2005), it illustrates the importance of monitoring to identify fluid movement and an adaptive approach to address problems identified.

Continued development is needed for MVA tools to improve aspects related to quantification and resolution of CO_2 in the subsurface, detection of fractures and other potential leakage paths, intermittent leakage, etc. (e.g., IPCC, 2005).

C.3.2 Potential Impact of Impurities in the CO_2 Stream

Impurities in CO_2 streams are manageable but could affect technical and non-technical considerations. Proper characterization of CO_2 injection streams will be required for determining well classification (e.g., proposed UIC Class VI well) and the applicability of other regulatory programs. Different CO_2 streams will have different compositions. For example, certain industrial processes (e.g., ammonia production and biofuel production) produce streams that are nearly pure CO_2. Natural gas combustion also produces a relatively pure waste stream. However, CO_2 streams from coal-fired power plants may contain minor impurities carried through from the coal.

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[6] See http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf.

Potential co-captured impurities that could affect subsurface processes include hydrogen sulfide (H_2S), and oxides of sulfur and nitrogen (SO_x and NO_x). In a post-combustion scenario (i.e., capture from a conventional coal-fired power plant), impurities may include sulfur dioxide (SO_2), NO_x, and oxygen (O_2). Emissions from an IGCC plant would contain H_2S instead of SO_2 and ammonia (NH_3) instead of NO_x. Also, the more volatile heavy metals (e.g., mercury, selenium, arsenic, and cadmium) and some organic impurities may be present in trace amounts. The amounts of these impurities are expected to be low, and would depend on the composition of the coal and efficiencies of any scrubbing steps (e.g., desulfurization), as well as the CO_2 capture technology.

SO_2 raises concerns because it may become oxidized to sulfate. Potential impacts include changes to the chemistry of the reservoir fluids (e.g., affecting the acidity or the oxidation potential) and dissolution or precipitation of minerals, which could, in turn, affect reservoir performance (e.g., injectivity and/or storage integrity). Modeling studies have approximated the effects of impurities on pH (e.g., Xu et al., 2004; Knauss et al., 2005). Their numerical simulations have indicated the potential for lowering of pH due to co-injection of SO_2. However, current understanding is limited by lack of knowledge about the rates of reactions between the injectate, formation fluids, and rock formations. Also, because there are currently no conventional coal-fired power plants that are capturing and injecting CO_2 into the subsurface, there are no field data with which to refine estimates from modeling. At this point, it is difficult to predict with certainty the effects of injection of trace SO_2. More research is needed, especially to assess the potential long-term effects on seal integrity.

H_2S is not expected to severely affect pH. Neither Xu et al. (2004) nor Knauss et al. (2005) predicted a significant pH change when H_2S co-injection was simulated. Although low pH does not appear to be a concern with H_2S injection, hydrogen sulfide is known to promote corrosion in steel. However, experience from analog operations (e.g., acid-gas disposal in Canada) is encouraging and suggests that the impact of impurities on (at least) some reservoirs is manageable.

Potential heavy metal concentrations in a captured CO_2 stream have been calculated by Apps (2006) and are expected to be very low. Non-volatile metals tend to remain associated with fly ash in coal combustion, and are not anticipated in CO_2 streams. Volatile and semi-volatile elements (mercury, arsenic, cadmium, and selenium) have a greater potential for remaining with the flue gas and being captured. Post-combustion treatment for particulates and SO_2 can remove a portion of the metals, but prediction of metals in a captured CO_2 injectate is difficult because of differences in coal compositions and plant operations. If conventional pulverized coal plants were to be retrofitted with CCS, newer Hg removal technologies and any improvements in fine particulate removal might render the issue of trace metals as potential constituents in CO_2 injectate insignificant. Only trace concentrations of organic compounds are expected (Sass et al., 2005).

All of these impurities would be injected along with the CO_2 into a well that must meet EPA's requirements for Class VI wells, which were developed based on the requirements and standards for Class I industrial and hazardous waste wells. The corrosion-resistant construction standards, periodic corrosion monitoring and mechanical integrity testing requirements in the geologic storage rule are specifically designed to address this risk.

Experience from analog operations (e.g., acid-gas disposal in Canada) is encouraging and suggests that the impact of impurities on (at least) some reservoirs is manageable, but more research is needed to assess the potential long-term effects on seal integrity. Acid-gas injection is found to be a good analogue for CO_2 storage, as it results in the long-term storage of significant amounts of CO_2. Because the equipment and geologic formations involved in acid-gas injection are similar to those required for CO_2 injection, much of the knowledge gained from acid-gas injection is directly applicable to CO_2 storage.

C.4 Additional Needs for Widescale Deployment

Workforce capacity may be a barrier for widespread deployment, including both project-related workforce needs (e.g., reservoir engineers, etc.) and permitting-related workforce needs at both the State and Federal levels.

Technical Capacity

Current technical capacity of State and Federal UIC programs to permit and ensure compliance may be a barrier to deployment. Current EPA training for UIC staff focuses on the key elements of UIC permits and on evaluating permit applications for completeness and technical accuracy. The UIC Program's training materials address evaluating geologic data (e.g., on USDWs and formation testing); well construction and pre-operational testing data; permit conditions for construction, operation, maintenance and monitoring; well plugging and abandonment requirements; addressing well failures; financial responsibility; and public participation in the UIC permitting process.

The new requirements for Class VI geologic sequestration wells would necessitate enhancements or additions to this training. New UIC Training Modules would need to be developed for UIC staff to complement the forthcoming Class VI guidances and provide the necessary detail to support the UIC Program's critical mission to ensure that USDWs are protected from endangerment. These modules may include the following:

- Applying for Class VI Primacy.
- Evaluating a Permit application for the construction of a Class VI well.
    - New site characterization considerations for the unique nature of CO_2 geologic storage.
    - Evaluating the proposed well design and construction, including the use of materials that are compatible with CO_2.
    - Evaluating the proposed Area of Review (AoR) for a Class VI well and the proposed multi-phase computational model.
    - Evaluating Class VI testing and monitoring plans, including the monitoring necessary to track the CO_2 and pressure front in the subsurface and the ground water monitoring plan.
    - Evaluating a Financial Responsibility demonstration.

- Granting Approval for CO_2 Operations.
    - Evaluating the Final AoR based on logging and testing.
    - Evaluating the testing to establish operating parameters and well shut-off triggers.
- Evaluating post-injection monitoring data and non-endangerment demonstrations.

State UIC Program Capacity Limitations

As noted in the report body, stakeholders have concerns about State UIC Programs' lack of adequate resources to handle the number and complexity of geologic sequestration projects. Workforce and technical capacity issues could be addressed by providing training to States on unique technical issues associated with geologic sequestration, providing technical support on permit reviews and issuance, or supporting compliance and enforcement activities. In addition to the workforce capacity development needs discussed in the body of the report, permitters will need guidance, training, and contractor assistance to analyze financial responsibility submissions in CCS permit applications. Currently, State or Federal permitters may not have the ability to assess financial instruments used to cover financial responsibility requirements for CCS. For example, if a permit application is submitted with insurance as part of the financial responsibility package, a permitter may not have the tools to determine if the right coverage limit was selected or if the risk analysis performed by the insurance company was adequate. In the case of self-insurance (financial statement), permitters will need guidance and training to select the appropriate financial ratios based on the financial health of the company. In addition to guidance and training for program staff, access to expert consultants who can troubleshoot will be critical for adequate review of CCS financial responsibility submissions. Additionally, State UIC primacy agencies' efforts could be aided by a national data system that would promote regulatory certainty, efficiency, and accountability, while allowing transparency of all geologic sequestration related information to improve public acceptance of CCS.

Pore Space

Definition of the ownership of injected CO_2 and pore space will be needed for wide-scale deployment. An efficient process for obtaining access to and the right to use surface property and pore space for site characterization and the life of the project may also be needed (unitization, etc.).

C.5 Outreach

Public outreach on geologic storage projects is critical to providing citizens with access to decision-making processes that may affect them, ensuring that the community receives adequate information about the proposed injection project, and allowing the permitting authority and owners or operators to become aware of public viewpoints on the project. Early and frequent public involvement through education and information exchange is key to the success of geologic storage and can provide insight into how the local community and surrounding communities perceive potential environmental, economic, or health effects associated with a specific geologic storage project.

It is important to ensure that mechanisms are in place for the public to access and synthesize storage project data (generally and on an individual site basis), including the following:

- stakeholders interested in launching and regulating projects,
- public education to address/forestall misinterpretations about this new technology, and
- engender commercial, regulatory, and public confidence.

Several efforts are already underway to developing a portfolio of outreach tools and approaches, including the following:

- Regional Carbon Sequestration Partnerships (RCSP)—each Partnership has tailored outreach to regional needs and stakeholders; outreach also tailored to each of the phases of the Partnerships (characterization phase, validation phase with small-scale injections, and demonstration phase with large-scale injections). RCSP experience suggests outreach to various stakeholders is critical from beginning of project throughout execution. Outreach needs may vary both between stakeholder groups and regionally.
- Best practice manual for outreach (based on RCSP experience) is anticipated to be released in 2010; Keystone Center has developed elementary and high-school curricula for CCS.

EPA plans to work with permitting authorities and geologic storage well owners or operators to involve the public by providing communities information about a geologic storage project as early in the process as possible. EPA is also developing outreach tools on geologic storage such as fact sheets, visual aids, and the use of social media, and will hold public meetings.

Appendix D. CO_2 Reuse

CO_2 reuse or utilization is the conversion of captured CO_2 to a useable product.[7] Similar to geologic storage of CO_2, such utilization allows for a net reduction of CO_2 emissions into the atmosphere by using CO_2 either directly or as a feedstock (IPCC, 2005). Such net reduction is possible only if two conditions are met: (1) use of the captured CO_2 must not simply replace a source of CO_2 that would then be vented to the atmosphere, and (2) compounds produced from the captured CO_2 must have a long lifetime (IPCC, 2005). For industrial processes, it is important to properly determine the system boundary in order to get an accurate determination of the net lifecycle CO_2 emissions based on material and energy balances (see IPCC, 2005 section 7.3.1 for more details).

CO_2 is a valuable industrial gas, and currently there are at least 22 commercial end-use sectors that use gaseous, liquid, or solid CO_2 (EPA, 2009), including food and beverage manufacturing and various chemical, pharmaceutical, and other processes that use CO_2 as an end product. This number excludes intermediate CO_2 processors and enhanced oil and gas recovery. However, it remains to be determined whether there is a net reduction of lifecycle CO_2 emissions from industrial processes using CO_2. Furthermore, the amount of CO_2 reuse in industrial processes is very small compared with the magnitude of CO_2 emissions from industrial sources. Industrial sources in the United States alone emit approximately 1.4 billion tonnes of CO_2 annually (EIA, 2010a).

Several options that are under investigation for CO_2 reuse range from conversion to biomass (e.g., via algae, microbes, plants), to conversion to a solid (e.g., plastics or ceramics), among others. The following sections briefly discuss the key options.

D.1 Potential Options for Reuse

Enhanced Oil Recovery: Current EOR processes in the United States are based mostly on CO_2 obtained from natural sources. Replacing the use of natural CO_2 with captured CO_2 would result in a net reduction of emissions to the atmosphere, assuming that a part of the injected CO_2 remains stored underground. Through 2008, approximately 560 million tonnes (NETL, 2010) of CO_2 have been injected in the United States for EOR. Currently, the United States uses approximately 50 million tonnes of CO_2 per year for EOR (Dooley, 2008). Using EOR, 30–60 percent of the reservoir's original oil can be extracted compared with 20–40 percent using primary and secondary recovery (DOE, 2010a). Figure D-1 shows annual U.S. oil production using EOR.

In this technique, CO_2 is injected into an operational oil field, where, in most cases, it mixes with the crude oil, causing it to swell and become less viscous—thereby maintaining reservoir pressures and oil production rates. CO_2 injection can also be used to sweep oil toward production wells. In both cases, revenue accrued through the sale of the additional oil produced can help to offset CO_2 injection costs.

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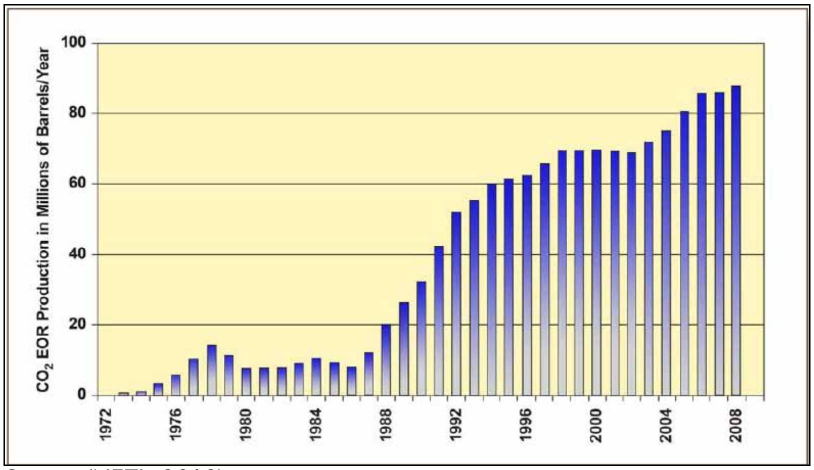
[7] Note that by this description and the discussion in this appendix, the Task Force does not intend to take a position on whether a particular process involves a solid waste subject to the requirements of RCRA.

Figure D-1. Growth of U.S. Oil Production from CO_2-based EOR



Source: (NETL, 2010)

Fuel Production: Most carbon-based fuels are made up of carbon, hydrogen, and oxygen. CO_2 can be hydrogenated to create low-carbon-chain fuel such as methanol. These hydrogenation reactions are exothermic in nature, although they require catalysts such as copper, zinc, or alumina. Procuring hydrogen requires energy for hydrolysis of water or partial oxidation of natural gas. If this energy can be based on non-fossil sources, then the complete process could have very low or even negative life-cycle carbon emissions footprint. However, Herzog et al. have shown that about six units of solar (or other non-fossil) energy would be needed to recycle the CO_2 generated from producing one unit of energy in a coal-fired power plant, if the hydrogen came from electrolysis of water (Herzog et al., 1993).

Chemical Synthesis: Ceramics, fertilizers, rubber, and many other small-scale industries require CO_2 at some stage of their manufacturing process. However, the amount of CO_2 that could be potentially used in these plants is rather small compared with emissions of CO_2.

The largest use of CO_2 in this area is in fertilizer plants, where CO_2 is captured from the exhaust gases of NH_3 reformer units and used to manufacture urea. Such chemical synthesis is already under application, and CO_2 emission from power plants can be routed to such units—although it is not clear if there will be net negative emissions from such applications. Laying of new pipeline for CO_2 would also be quite expensive and increase lifecycle CO_2 emissions.

Polymer Synthesis:[8] CO_2 can be viewed as a C_1 building block of a long carbon chain polymer. However, using CO_2 requires the development of efficient catalysts and additional energy for reducing CO_2. Finding an efficient reducing catalyst or net low-energy-intensive process to reduce the CO_2 has been the challenge so far. However, CO_2 can be used in place of phosgene in polyurethane and polycarbonate manufacturing, as phosgene is toxic. Overall potential for CO_2 use in polymer synthesis is not significant because of additional energy uses and low consumption. For example, if the U.S. plastic industry relies exclusively on captured

[8] Summarized from Section 7.3.3.1 of IPCC (2005).

CO_2, it can potentially use about 100 million tonnes of CO_2, around 5 percent of annual CO_2 emission from the power sector (Herzog et al., 1997).

Bio-fuel production using Algae: Plants convert CO_2 and water into starch using sunlight during the photosynthesis process. Although more advanced plants are not very effective in conversion of large quantities of CO_2, micro-algae can use high concentrations of CO_2 to create starch. The biomass product can be used to recycle CO_2 into valuable industrial fuel such as methane, methanol, hydrogen and bio-diesel. However, the CO_2 removed by conversion to bio-fuel will be added back in the environment once it is burned. Also, it will require additional energy to convert the CO_2 to bio-fuel such as in harvesting, fertilizers, etc. Overall, the conversion efficiency is limited by photosynthetic efficiency. At present, micro-algae convert solar energy with one percent efficiency, implying that a solar collection area as large as 20 square miles is needed to convert CO_2 emissions of a 100 MW power plant. However, there is significant ongoing research in this area (IPCC, 2005).

Carbonation: Alkaline earth metal oxides react with CO_2 to create insoluble carbonates. Rocks with high metal oxide concentrations can be used to store significant amounts of CO_2 in the form of carbonates. The technology for mineral carbonation is not yet mature enough to allow for a proper assessment of costs and performance, but there will be rather high costs associated with mining (similar to the scale of current global coal mining) and disposal issues.

D.2 Role of CO_2 Utilization in Climate Change Mitigation

Several factors determine the viability of CO_2 reuse, and there are currently significant technical barriers to commercial-scale reuse. First, rates of conversion must be comparable to rates of CO_2 capture. Second, energy requirements for conversion must be low. Third, potential volumes of reactants and/or products may limit the scale of reuse relative to total emissions. Finally, reuse options need to consider the long-term fate of CO_2 and its lifecycle emissions.

In summary, there are limited commercial uses for captured CO_2, such as in food and beverage manufacturing, pulp and paper manufacturing, the rubber and plastic industry, fire suppression, and refrigeration and cooling. No market is expected to develop for reuse of CO_2 on a scale that would significantly affect a strategy to roll out CCS on a national basis by 2016.

Appendix E. Research, Development, & Demonstration

E.1 Research and Development

Capture

Two Research, Development and Demonstration (RD&D) technology pathways are being pursued globally for combining coal-fueled power generation with CCS. The first is based on pulverized coal (PC) power plant technology, which is used worldwide in nearly all utility-scale coal power plants. It will be the focus of retrofit applications, and could also find applications for new power plants. The second is based on coal gasification technology. Gasification-based power generation is far less mature than PC technology, but it is believed by many to be the pathway leading to the most cost-effective CCS options.

The highest priority RD&D is on capture technology using innovative solvents, solid sorbents, and membranes to extract CO_2 from flue gas. RD&D is focused on areas such as reducing regeneration energy and material cost, and increasing reaction speed (solvents and sorbents), durability, and tolerance to pollutants, and CO_2 selectivity (membranes). Advanced capture technology could reduce the increased cost of electricity due to adding CCS to a supercritical PC power plant from current estimates of an 80 percent increase to as low as a 30 percent increase. Further CO_2 reductions would be possible if advanced boiler materials are developed leading to a new generation of more efficient ultra supercritical PC power plants that have a significantly smaller carbon footprint per power output.

Although several IGCC demonstration plants (as described in Appendix A) are operating worldwide, the strategy for IGCC RD&D is to continue to improve the cost and performance of key plant components, including those that will lead to higher availability. Current RD&D is focused primarily on advanced combustion turbines, warm gas clean-up and H_2/ CO_2 separation membranes, coal feed pumps, and ion transport membranes for low-cost oxygen production.

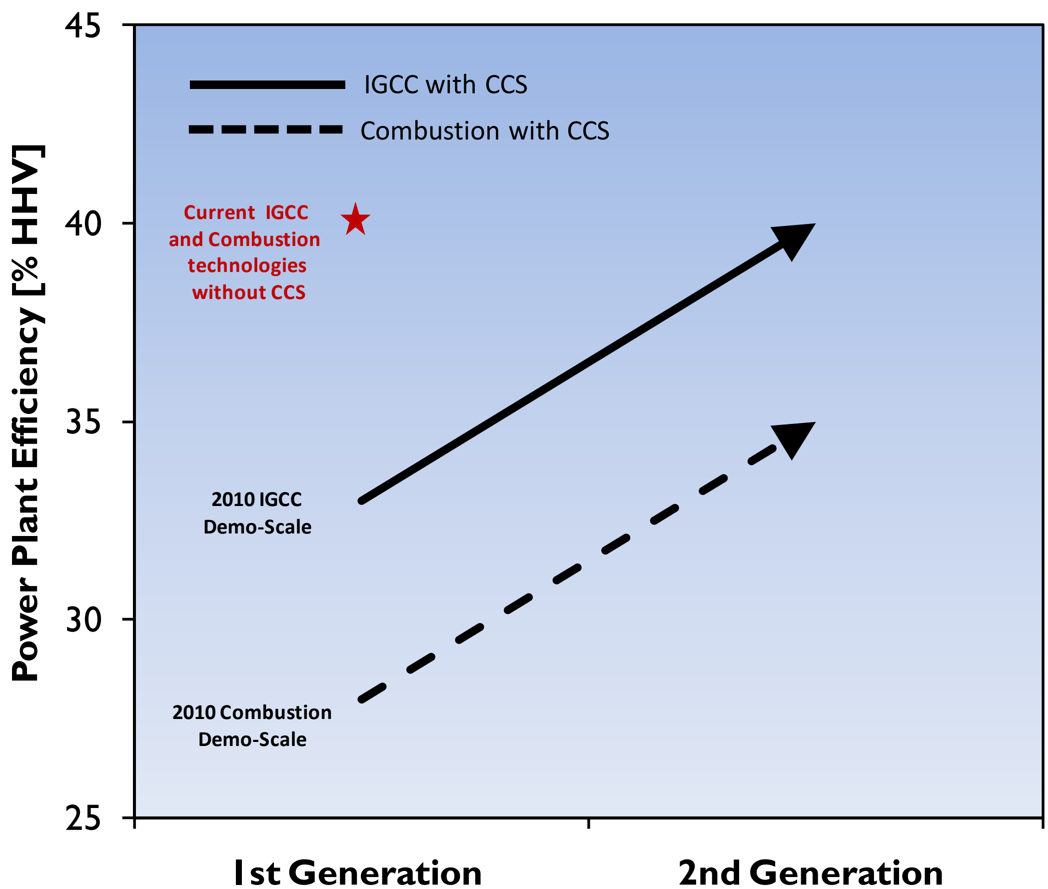
The ongoing DOE CO_2 capture technology R&D program for post-combustion and oxy-combustion capture is working to develop advanced 2^{nd} generation technologies capable of 90 percent CO_2 capture with a target of less than a 30 percent increase in the COE over a comparable plant without CCS. For pre-combustion capture (IGCC applications), the DOE goal is to provide electricity with less than a 10 percent increase in the COE compared to the same power plant without CCS. As shown in Figure E-1 and Figure E-2, accomplishing these goals will require significant efficiency and cost improvements (capital and operating) for conventional PC and IGCC power plants. The current DOE CO_2 capture technology R&D timeline to accomplish those goals includes the following major milestones (DOE, 2010):

- By 2016, complete small-scale field testing of 2nd generation CO_2 capture technologies and components that demonstrate significant reduction in CO_2 capture cost and energy penalties compared with current technologies. The field testing will be between 0.5 to 5 MWe scale from pilot plant facilities and/or slipstream treatment at operating coal-based power plants.

- By 2020, complete large-scale field testing at 25 MWe of 2nd generation CO_2 capture technologies and integrated oxy-combustion systems that demonstrate significant reduction in CO_2 capture cost and energy penalties compared with current technologies.

As shown in Figure E-1 below, accomplishing these goals will require significant efficiency improvements for IGCC and conventional PC power plants. The IGCC with 2nd generation CCS efficiency improvement includes advances in air separation (membranes), hot/warm gas cleanup, combustion turbines and CO_2 capture and compression technologies. With successful development of these technologies, the IGCC with 2nd generation CCS efficiency increases from 33 percent to 40 percent. Likewise, improvements in advanced air separation, ultra-supercritical boiler materials, CO_2 capture and compression technologies will improve the PC with 2nd generation CCS efficiency from 28 percent to 35 percent.

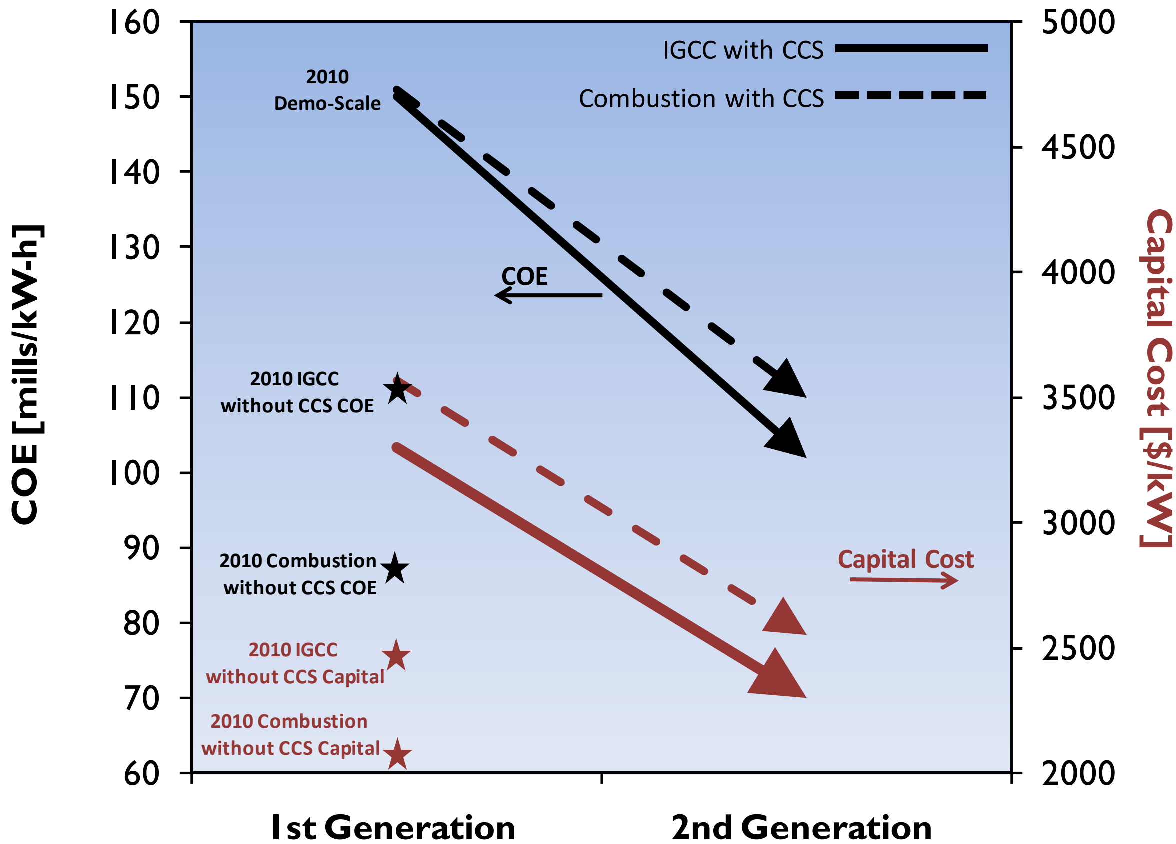
Figure E-1. DOE CCS R&D Efficiency Improvement Targets



Source: NETL (2009b) and NETL (2009c)

As shown in Figure E-2 below, accomplishing these COE goals will also require significant capital cost improvements. Combined with efficiency improvements, the COE for IGCC with 2nd generation CCS would decrease by 32 percent (from 150 mills/kWh to 102 mills/kWh). Likewise, improvements in PC plant capital costs (such as smaller CO_2 capture and compression equipment size) would result in a 30 percent decrease in COE (from 151 mills/kWh to 110 mills/kWh).

Figure E-2: DOE CCS Cost Improvement Targets



Source: NETL (2009b) and NETL (2009c)

Upon successful development at the laboratory through pilot-scale (5-25 MW), the advanced 2nd generation technologies showing the most promise in terms of reducing costs and energy penalties could warrant further development and demonstration at full-scale before commercial acceptance, which may take on the order of a decade. The relative roles of the government and the private sector in these more advanced stages of CCS development and scale-up should be carefully evaluated.

Storage

DOE's CO_2 storage activities involve three key elements for technology development: Core RD&D, Infrastructure, and Global Collaborations. The Core RD&D element includes geologic storage, MVA, and simulation and risk assessment. It also includes American Recovery and Reinvestment Act (ARRA) University Projects, which focus on training undergraduate and graduate students in the five Core RD&D focus areas. Applied research is identified through lessons learned from the Infrastructure and Global Collaborations elements and conducted through the Core RD&D Program to meet the following goals:

- Validate enhanced CO_2 trapping and storage capacity, determine reservoir theoretical capability to store CO_2 (with impurities if present), and test stimulation and completion technologies to enhance injectivity of storage formations.
- Assess the development of a cost-effective "toolbox" to monitor plume migration in deep geologic formations, complete a material balance, and develop protocols to enable 99 percent of stored CO_2 to be accredited as net emissions reductions.
- Assess the improvements to existing simulation codes to enhance prediction of plume migration, develop a "systems" approach(es) to risk assessment for field sites, and develop and validate coupled risk assessment process models for large-scale projects.
- Determine promising areas of CO_2 utilization, using fundamental and bench-scale testing and research.
- Determine viability of managing produced water from geologic storage projects for beneficial applications.

Technologies are validated at test sites in the United States and Canada, and ongoing data collection is used to confirm geologic storage capacity and effectiveness.

The second element, infrastructure, includes the RCSP Initiative, other large-scale projects, and ARRA Regional Technology Training and Site Characterization. The focal point of the Infrastructure element is the RCSP Initiative, which is a government/industry cooperative effort tasked with developing guidelines for the most suitable technologies, regulations, and infrastructure needs for CCS in different regions of the United States and Canada. The RCSP Initiative is composed of seven partnerships encompassing 43 States, four Canadian provinces and more than 350 organizations, including NGOs. The RCSP Initiative is implemented in three phases:

- Characterization Phase (2003–2005): The partnerships completed the initial characterization of their regions' potential to store CO_2 in different geologic formations.
- Validation Phase (2005–2010): The partnerships are concluding validation of the most promising regional storage opportunities through a series of small-scale field tests. This phase builds upon the Characterization Phase accomplishments and field tests of geologic and terrestrial storage technologies to provide the technical foundation for Development Phase activities.
- Development Phase (2008–2017): The partnerships are beginning to implement large-scale field testing involving at least 1 million tonnes of CO_2 per project to confirm that CO_2 injection and storage can be achieved safely, permanently, and economically.

Data and maps generated through all three phases of the RCSP Initiative are used to estimate the potential U.S. geologic CO_2 storage capacity. This information is integrated into the Carbon Sequestration Atlas and the National Carbon Sequestration Database (NATCARB) and Geographical Information System. The Atlas is updated every two years, and NATCARB is updated in real time.

ARRA project areas also contribute to the Infrastructure element. Regional Technology Training provides training to next-generation engineers and scientists; and Site Characterization characterizes additional promising formations for geologic storage through investigations at 10 site locations. Work conducted through the RCSP Initiative and other Infrastructure activities benefits the DOE CCS Program by developing human capital, encouraging stakeholder networking, providing data for policy development, and developing visualization knowledge centers, best practices manuals, and public outreach and education.

The majority of CO_2 operations today are occurring in tandem with business-as-usual EOR, with little effort spent on accounting for the CO_2. To enable widespread, safe, and effective CCS within the next 10 years, commercial demonstration projects should include storage in different geologic reservoir classes. DOE is currently conducting its CCPI and ICCS demonstration projects to determine effects of variation in CO_2 supply on storage operations. In addition, the RCSP program plans to conduct nine large-scale injection and storage demonstration projects in a variety of geologic reservoirs. Knowledge generated from monitoring the fate and transport of the injected CO_2 at these projects will help inform the production of Best Practice Manuals to guide future deployment of CCS.

E.2 Demonstrations of CCS Technology

DOE's CCPI is a cost-shared collaboration between the Federal government and industry to speed investment in low-emission coal technology by demonstrating and accelerating the commercial deployment of advanced coal-based power generation technologies. Recent project selections have focused on proving the feasibility of integrating CO_2 management and power production, and facilitating the movement into the marketplace of technologies emerging from DOE's core research and development activities. Six integrated CCS projects are currently proceeding under CCPI. Of these, three are new IGCC plants with pre-combustion capture and three are post-combustion capture from PC power plants.

In addition to fossil-fueled power plants, there are large industrial CO_2 emitters that could be candidates for CCS. Industrial plants may find it more difficult than power plants to finance early CCS projects because they cannot necessarily rely on consumers to pay the incremental cost of the technology (whereas public utility regulators may approve such cost recovery mechanisms for regulated utilities). Recognizing the importance of this CCS market, Congress recently made funding available through ARRA for industrial CCS demonstrations. These projects currently include large-scale CCS for commercial and industrial sources such as cement plants, chemical plants, refineries, steel and aluminum plants, and manufacturing facilities.

The above suite of demonstration projects, in tandem with commercial projects supported by Federal loan guarantees, tax incentives, and various incentives at the State level, should cover a sufficiently large group of CCS options to allow widespread deployment. However, certain key areas may not be adequately covered. For example, a relatively small number of the above-mentioned projects plan to inject captured CO_2 into deep saline formations. None of the current suite of projects inject into offshore formations. Additionally, based on historical program data and especially given current economic conditions, not all of these projects should be expected to move forward to completion.

Appendix F. Applicability of Selected Environmental Laws to the Storage Phase of Carbon Capture and Storage

F.1 Introduction

The purpose of this appendix is to consider the applicability of the Safe Drinking Water Act; the Resource Conservation and Recovery Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Emergency Planning and Community Right-To-Know Act; and the Clean Air Act to the storage phase of CCS.[9] In the recently proposed rule entitled *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide*, 75 Fed. Reg. 18576, 18578 (April 12, 2010), EPA noted that it may be appropriate for a wide variety of sources to mitigate sizeable GHG emissions through CCS. This includes sources in such sectors as "electric power plants (existing and new), natural gas processing facilities, petroleum refineries, iron & steel foundries, ethylene plants, hydrogen production facilities, ammonia refineries, ethanol production facilities, ethylene oxide plants, and cement kilns." *Id.*

F.2 Safe Drinking Water Act (SDWA)

CO_2 underground storage sites are regulated through the SDWA Underground Injection Control (UIC) Program.

Underground injection wells are regulated under the authority of Part C of SDWA. SDWA §1421, 42 U.S.C. § 300h, requires EPA to establish requirements for State UIC programs to prevent endangerment of USDWs from "the subsurface emplacement of fluids by well injection . . . ." 40 C.F.R. Parts 144-148. 40 C.F.R. § 144.3 defines "fluid" as "any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state." UIC permits are issued for injection wells onshore and those requirements can be implemented for wells inside State territorial waters.[10]

Since 1974, EPA has established requirements for five classes of UIC wells: industrial, municipal, hazardous, and radioactive waste wells (Class I); wells associated with enhanced oil and gas production and waste disposal (Class II); solution mining wells (Class III); shallow hazardous waste wells (Class IV, which are essentially banned); and all other wells (Class V).[11]

Under § 1421(b), SDWA mandates that EPA develop minimum Federal requirements for State UIC primary enforcement responsibility, or primacy, to ensure protection of USDWs.[12] In

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[9] These environmental statutes are directly implicated by CCS; however, there may be circumstances in which other environmental laws, such as the Federal Water Pollution Control Act in the case of a discharge of a pollutant from a point source to a water of the United States, would apply in the context of CCS. 33 U.S.C. §§ 1311(a) and 1362(7), (12). Further, natural resources and public lands laws such as the National Environmental Policy Act (NEPA), the Endangered Species Act, the Federal Land Policy and Management Act, and the Mineral Leasing Act, will also apply according to their terms.

[10] 40 C.F.R. § 144.1(g)(1).

[11] 40 C.F.R. Parts 144, 146, and 148.

[12] Reference to "States" includes tribes and territories.

order to implement the SDWA UIC Program, States, Tribes, and territories must apply to EPA for primacy approval. Under § 1422, States have 270 days to submit their program to EPA for approval. A State applying for primacy (except for Class II) under § 1422 must show that its program is at least as stringent as the Federal minimum requirements provided for in the Federal regulations.[13] Within 90 days of a State's application, and after there has been "reasonable opportunity for presentation of views, the Administrator shall by rule either approve, disapprove, or approve in part and disapprove in part, the State's underground injection control program."[14]

Injectate CO_2, which is a supercritical fluid, meets the definition of "fluid" in SDWA.[15] CO_2 exists as a supercritical fluid at high pressures and temperatures, and in this state exhibits properties of both a liquid and a gas. SDWA's UIC regulations apply to all CO_2 sequestration well sites across the United States, including wells that are located inside a State's territorial waters. CO_2 sequestration well sites are regulated under the UIC program regardless of capture technology. Current options for permitting UIC wells that inject CO_2 include Class I industrial, Class II, or Class V experimental wells.[16]

In 2008, EPA proposed Federal requirements for underground injection of CO_2 for purposes of geologic sequestration.[17] The proposal applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage. It proposes a new class of well (Class VI) and tailors minimum technical criteria for geologic site characterization, area of review, corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure to the unique nature of CCS. This is to ensure that the injection of large volumes of CO_2 in a variety of geologic formations would not endanger USDWs. EPA plans to go final with the Class VI rulemaking in late 2010. Until the Class VI rulemaking goes final and into effect, CCS will continue to be permitted under the existing UIC program including existing State primacy authorities.

F.3 Resource Conservation and Recovery Act (RCRA)

RCRA provides authority to address waste injectate CO_2 that may present an imminent and substantial endangerment to human health and the environment. RCRA hazardous waste requirements may apply to certain injectate CO_2.

The Solid Waste Disposal Act, as amended (commonly referred to as RCRA), generally regulates "solid wastes," with Subtitle C of the Act addressing management of solid wastes that are also "hazardous wastes." RCRA Subtitle C is designed to be implemented by authorized

[13] 40 C.F.R. Part 145.

[14] SDWA § 1422(b)(2), 42 U.S.C. § 300h-1(b)(2).

[15] In § 706 of the Energy Independence and Security Act of 2007, 42 U.S.C. § 17254, Congress made SDWA applicable to CCS through the provisions of the Department of Energy Carbon Capture and Sequestration Research, Development, and Demonstration Act of 2007.

[16] In March 2007, EPA issued *Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects—UIC Program Guidance (UICPG #83)*.

[17] 73 Fed. Reg. 43492 (July 25, 2008).

States in lieu of a Federal program, with Federal oversight. RCRA Subtitle C establishes a comprehensive "cradle to grave" regulatory scheme, including requirements for generators and transporters, along with permitting and other requirements for hazardous waste "treatment, storage, or disposal" facilities. Violations of RCRA Subtitle C requirements are subject to civil and criminal enforcement, and RCRA provides authority for the United States to take civil action to prevent imminent and substantial endangerment due to the handling, transporting, disposing, or other actions related to a solid or hazardous waste.[18]

RCRA defines "solid waste" as "any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations . . . ."[19] EPA has promulgated extensive regulations further defining what is a solid waste for hazardous waste regulatory purposes.[20]

RCRA applies at the point at which a waste is generated.[21] Among the possible points of "generation" are: (1) the point at which CO_2 is captured as a gas, (2) the point at which CO_2 is compressed to form a supercritical fluid (exhibiting the properties of both a liquid and gas), and (3) the point at which CO_2 is injected as a supercritical fluid. At any of these points, CO_2 bound for permanent sequestration is likely to be considered a "solid waste" under the RCRA statute because it would be subsequently "discarded" "liquid [or] contained gaseous material resulting from industrial [or] commercial . . . operations . . . ." This means that, irrespective of its status as a hazardous waste, RCRA § 7003 is available to address activities concerning CO_2 bound for sequestration that may present an imminent and substantial endangerment to human health and the environment.

CO_2 bound for permanent sequestration, if it were to qualify as a hazardous waste, is also likely a solid waste for purposes of the RCRA hazardous waste regulations. It is "liquid [or] contained gaseous material resulting from industrial [or] commercial . . . operations . . ." being "discarded" (abandoned for disposal). [22,23,24]

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[18] RCRA §§ 3001-05, 3007-08, and 7003, 42 U.S.C. §§ 6921-25, 6927-28, and 6973; 40 C.F.R. Parts 260-279.

[19] § 1004(27), 42 U.S.C. § 6903(27).

[20] 40 C.F.R. § 261.2.

[21] Regulation from the point of generation has been upheld as a permissible construction of the RCRA statute. *Chemical Waste Management v. EPA*, 976 F.2d 2, 14 (D.C. Cir. 1992), *reh'g denied*, 985 F.2d 1075 (D.C. Cir.), *cert. denied*, 507 U.S. 1057 (1993).

[22] Hazardous secondary material which is used or re-used as a substitute for a commercial product or as an ingredient in an industrial process to make a product may be excluded from the definition of solid waste under RCRA regulations. EPA's regulations may apply to CO_2 that has been geologically sequestered if it is being stored for re-use in a product or ingredient. See 40 C.F.R. §§ 261.1(c)(5) and 261.2(e). To qualify for this exclusion, however, the hazardous material must be legitimately recycled. In addition, the hazardous material cannot be accumulated speculatively, meaning generally that 75 percent of the accumulated material must be used within a calendar year. 40 C.F.R. § 261.1(c)(8). Further, the EPA regulations state that this hazardous material may not be burned for energy recovery nor re-used in a manner that constitutes disposal (i.e., being put on the land or used to make a product that is put on the land). See 40 C.F.R. § 261.2(c). Currently, there are 22 commercial end-use sectors that use gaseous, liquid, or solid CO_2 (excluding enhanced oil and gas recovery); see the *General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide—Appendix A in the docket to the Proposed*

Under EPA's regulations, generators of solid waste are required to determine whether their wastes are hazardous wastes.[25] A solid waste is a hazardous waste if it exhibits any of four characteristics of a hazardous waste (ignitability, corrosivity, reactivity, or toxicity),[26] or is a listed waste[27] (these include various used chemical products, byproducts from specific industries, or unused commercial products).

CO_2 is not a listed RCRA hazardous waste. From current technical knowledge, it is unlikely to exhibit the characteristics of ignitability, reactivity, or corrosivity at the point of capture or compression or injection for permanent storage. CO_2 captured from sectors amenable to CCS could contain toxic chemical constituents such as arsenic, mercury, and selenium (IPCC, 2005; Apps, 2006). Whether a particular CO_2 stream is a hazardous waste based on toxicity will depend on whether it contains one or more specific chemical constituents at levels above the toxicity characteristic concentrations in Table 1 of 40 C.F.R. § 261.24(b). EPA stated in the proposed UIC CCS regulation, 73 Fed. Reg. at 43503, that it "cannot make a categorical determination as to whether injected CO_2 is hazardous under RCRA." (EPA could make a categorical determination through the rulemaking process.) EPA noted that "[t]he composition of the captured CO_2 stream will depend on the source, the flue gas scrubbing technology for removing pollutants, additives, and the CO_2 capture technology. In most cases, the captured CO_2 will contain some impurities, however, concentrations of impurities are expected to be very low."[28] Should a facility adjust its processes to create a solid waste that does not contain chemical constituents at levels above the toxicity characteristic concentrations in Table 1 of 40 C.F.R 261.24(b), such waste stream likely would not be subject to Subtitle C requirements as a RCRA hazardous waste.

In response to that proposal, EPA received comments asking for clarification of how RCRA hazardous waste requirements apply to CO_2 streams. EPA is planning a proposed rule under RCRA to explore a number of options. Among the options under consideration by EPA is the development of a "conditional exemption" from RCRA requirements for hazardous CO_2 streams in order to facilitate implementation of CCS while protecting human health and the

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Rule for Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide (75 Fed. Reg.18576). However, while there might be limited commercial uses for captured CO_2, such as in food and beverage manufacturing, pulp and paper manufacturing, the rubber and plastic industry, fire suppression, and refrigeration and cooling, no market is expected to develop for re-use of stored CO_2 in the regulatory time frame and the amounts at which CO_2 storage should occur on national scale-up of the CCS program.

[23] For purposes of this report, it is assumed that the CO_2 is captured from one source and transported to a permanent storage site. On scale-up of a national CCS program, it is possible that different waste streams of CO_2 may be combined for transport to a storage site or sites. Depending on the nature of the CO_2 streams being mixed, the resultant mixture may contain different co-constituents at different concentrations, and may need to be re-evaluated. This is a highly fact-specific analysis, which we merely flag for purposes of this report.

[24] 40 C.F.R. §§ 261.2(a)(1)-(2), (b)(1).

[25] 40 C.F.R. § 262.11.

[26] 40 C.F.R. §§ 261.20-.24.

[27] 40 C.F.R. §§ 261.30-.33.

[28] 73 Fed. Reg. at 43503.

environment. EPA has created "conditional exemptions" in the past defining waste as hazardous only if it is not managed pursuant to specified conditions.[29]

F.4 Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

CERCLA may apply to certain releases from a CO_2 storage site. CERCLA § 104(a), 42 U.S.C. § 9604(a), authorizes the President to respond to a release or substantial threat of release of hazardous substances, or pollutants or contaminants that present an imminent and substantial danger into the environment. Under § 101(22), 42 U.S.C. § 9601(22), "release" is broadly defined and includes "any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment . . . ." Under § 101(8), 42 U.S.C. § 9601(8), "environment" is broadly defined and includes surface water, ground water, land surface or subsurface strata, and ambient air within the United States or under the jurisdiction of the United States. Under §101(14), 42 U.S.C. § 9601(14), "hazardous substance" is any substance EPA has designated under specified provisions of the Clean Air Act, the Clean Water Act, the Toxic Substances Control Act, and the Resource Conservation and Recovery Act. EPA may also designate additional substances as hazardous substances under CERCLA. EPA maintains and updates a list of hazardous substances in 40 C.F.R. Part 302. Under § 101(33), 42 U.S.C. § 9601(33), "pollutant" or "contaminant" is any other substance not on the list of hazardous substances that "will or may reasonably be anticipated to cause" adverse effects in organisms or their offspring.

There are four elements necessary to establish liability under CERCLA § 107(a) 42 U.S.C. § 9607(a): (1) there must be a release or threatened release of a hazardous substance, (2) the release must occur at or from a facility,[30] (3) the release must cause the plaintiff to incur response costs not inconsistent with the National Contingency Plan, and (4) the defendant must fall within one of the four categories of responsible persons. See *Young v. United States*, 394 F.3d 858, 862 (10th Cir. 2005). Liability under CERCLA is strict without regard to fault. Liability is also generally joint and several, which means that any one responsible party can be held liable for cleanup costs even if other parties are also responsible for the release, unless the responsible party can show that the harm is divisible. As is common under CERCLA, there is no statutory or regulatory exclusion for CCS activities, and it is this potential liability that has raised concern about the viability of CCS projects.

Based on information we have to date on the potential chemical composition of the injectate, it appears that under likely capture scenarios the injectate will contain hazardous substances (e.g., arsenic and selenium). CO_2 storage projects almost certainly fall within the definition of a facility.[31] Current owners and operators of CO_2 storage projects, past owners or operators at

[29] See, e.g., *Military Toxics Project v. EPA*, 146 F.3d 948 (D.C. Cir. 1998).

[30] The terms "release" and "facility" are defined broadly in the statute and can be found at CERCLA §§ 101(22) and 101(9), respectively, 42 U.S.C. § 9601(22) and (9) (see above).

[31] CERCLA defines the term "facility," inter alia, as "any site or area where a hazardous substance has been deposited, stored, disposed of, or placed, or otherwise come to be located . . . ." CERCLA § 101(9), 42 U.S.C. § 9601(9).

the time of disposal, persons who arranged for the disposal of injectate at a storage project, and persons who transported captured CO_2 to a storage project are subject to liability under CERCLA if a plaintiff were to incur cleanup costs responding to a release of hazardous substances at or from the facility. Consequently, CERCLA liability could apply, unless such persons could establish a defense. Moreover, if CO_2 released to groundwater caused the additional release of hazardous substances, such as heavy metals, from adjacent substrata, then the owner of that "facility" (the substrata) could be considered a facility owner under CERCLA § 107(a)(1), 42 U.S.C. § 9607(a), who might become liable for any response costs caused by that release.

One potential defense for CCS project owners and operators is to argue that the injectate qualifies as a "Federally permitted release" under CERCLA § 101(10)(G), 42 U.S.C. § 9601(10)(G). Permits issued under the underground injection control program could qualify for an exception to CERCLA liability under CERCLA § 107(j), 42 U.S.C. § 9607(j). Courts, however, have applied the exception narrowly. Liability protection applies to releases that occur under a finalized permit, within the scope of the language and limits of the permit, and during the time the permit is valid. Releases which occur outside of a permitted area would likely not qualify for the exception.[32] Accordingly, permits that define the permitted area broadly to include the entire subsurface that CO_2 is reasonably expected to occupy through migration would provide for the broadest application of the "Federally permitted release" exclusion.

There are no regulatory options for exempting CCS projects from CERCLA liability. Because the term "hazardous substance" is broadly defined in CERCLA § 101(14), 42 U.S.C. § 9601(14), CO_2 injectate would still be considered a hazardous substance even if regulatory exemptions are created under other statutes, such as RCRA. In other words, if the injectate were to be conditionally exempt under RCRA, but still contained hazardous substances listed in 40 C.F.R. Part 302, the injectate would still be potentially subject to CERCLA response actions and potential liability. Accordingly, absent qualifying as a Federally permitted release, some kind of statutory change would be required if a policy decision were made that a CERCLA exemption for CO_2 injectate would be appropriate.

CO_2 injectate could also be subject to release reporting requirements under CERCLA § 103(a), 42 U.S.C. § 9603(a), which serves to alert Federal authorities so they may make a timely evaluation of whether a response action is needed. There is, however, an exception for Federally permitted releases.

[32] At least one court has found that seepage from permitted tailings ponds into an underlying aquifer did not fall within the scope of the permit for the tailings ponds. *United States v. United Nuclear Corp.*, 814 F. Supp. 1552, 1564-65 (D.N.M. 1992). The court found that the permits were clear and did not authorize the seepage, even though the permit holders and the regulatory authorities knew there would be some seepage. *Id*.

F.5 Emergency Planning and Community Right-To-Know Act (EPCRA)

If EPA interprets "facility" to include the subsurface injection site, EPCRA would impose emergency planning requirements. Release reporting requirements might apply to certain releases outside the facility or outside the scope of a Federal permit.

In general, EPCRA establishes release reporting requirements and emergency planning requirements for hazardous substances (HS) listed in 40 C.F.R. § 302.4 and extremely hazardous substances (EHS) listed in 40 C.F.R. Part 355 App. A, B. Based on information we have to date on the chemical composition of the injectate, it appears that under likely capture scenarios the injectate will contain both HS and EHS. How these hazardous substances are treated for release reporting and emergency planning purposes will depend on what is considered as the CCS "facility."[33] Release reporting and planning requirements will differ depending on whether the agency interprets the facility to include only the structures on land surface, or whether the facility also includes the subsurface injection site.

EPCRA § 304, 42 U.S.C. § 11004, requires the owner or operator of a facility to notify State and local authorities of unpermitted releases into the environment of a reportable quantity (RQ) of an HS or EHS. Releases that occur solely within the facility boundaries or that are Federally permitted are exempt from having to report. If the agency chooses to interpret the EPCRA facility as including the subsurface injection site, release reporting under EPCRA § 304 would not be required if the release does not cross the facility boundaries. Release reporting would be required if the release crossed the facility boundaries, the release was not Federally permitted, and the amount of HS or EHS in the CO_2 injectate exceeded the RQ.

EPCRA § 302, 42 U.S.C. § 11002, requires the owner or operator of a facility to provide a one-time written notification to State and local authorities of an EHS present at the facility at any one time in amounts equal to or greater than the threshold planning quantity (TPQ) for that substance. If the agency chooses to interpret the EPCRA facility as including the subsurface injection site, emergency planning requirements would apply under ECPRA § 302 if the amount of EHS in the CO_2 injectate exceeded the TPQ.

There is no exclusion for CCS projects from EPCRA reporting requirements. If a policy decision were made that an exemption would be appropriate, EPA could explore the possibility of a regulatory exemption as it did for radionuclides in 40 C.F.R. § 355.40.

F.6 Clean Air Act (CAA)

The CAA's nonattainment new source review (NSR) and prevention of significant deterioration (PSD) preconstruction review programs may apply to some geologic sequestration facilities.[34] EPA has proposed a rule to require monitoring and reporting of CO_2 injection and sequestration.

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[33] EPCRA § 329(4), 42 U.S.C. § 11049(4).

[34] CAA §§ 173 and 165, 42 U.S.C. §§ 7503 and 7475.

NSR applies to the emissions of any criteria pollutant for which an area is designated as nonattainment for a national ambient air quality standard (NAAQS); PSD applies to emissions of criteria pollutants in areas designated as in attainment of the NAAQS and of all other regulated pollutants (except those designated as "hazardous air pollutants" under § 112 of the CAA). Although CO_2 is not currently a regulated air pollutant under the CAA, this will change once the standards in EPA's Light-Duty Vehicle Rule take effect in 2011.[35] At this time, the change in the regulatory status of CO_2 is not anticipated to have a direct substantial impact on the PSD requirements applicable to geologic sequestration facilities.

The question of whether either the NSR or PSD program would apply to a geologic sequestration facility will depend on the amount of potential air emissions from the equipment at the facility. A geologic sequestration facility with sufficient potential air emissions to trigger NSR or PSD would be required to obtain a permit before commencing construction. (For GHGs, EPA addressed the triggering threshold for PSD by issuing a rule exempting smaller sources of these pollutants from PSD permitting until at least 2016.[36]) An NSR or PSD permit would require the installation of state-of-the art pollution controls on emissions units at the geologic sequestration facility, such as compressors. In addition, under certain circumstances, permitting authorities might also consider whether controls on fugitive emissions of CO_2, if any, would be appropriate as part of a PSD review; however, it is worth noting that a well-designed geologic sequestration facility is unlikely to have significant potential emissions of CO_2. As a result, the CO_2 sequestered underground at such a facility would not normally trigger PSD review or be subject to PSD control requirements.

The NSR and PSD programs are generally implemented by the States, under an EPA-approved State Implementation Plan. A few States do not have approved PSD programs; in these areas, EPA or States acting under a delegation from EPA issue PSD permits. EPA is also the PSD permitting authority on tribal lands. The tribes may adopt PSD rules but none have done so thus far. For sources located offshore of the United States, the CAA requires certain sources located on the Outer Continental Shelf to obtain permits that meet the requirements of PSD. EPA is the permitting authority for these sources.

EPA has also proposed to amend the Greenhouse Gases Reporting Program at 40 C.F.R. Part 98, issued under the authority of CAA § 114, 42 U.S.C. § 7414, to add reporting and recordkeeping requirements for owners and operators of facilities that conduct injection and geologic sequestration of CO_2.[37] Facilities that conduct geologic sequestration would be required to develop and implement an EPA-approved site-specific monitoring, reporting, and verification plan; and to annually report the amount of CO_2 sequestered, by subtracting total CO_2 emissions (such as the amount if any leaked to the surface or vented from surface equipment) from the CO_2 injected in the reporting year.

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[35] 75 Fed. Reg. 17004 (April 2, 2010).

[36] 75 Fed. Reg. 31514 (June 3, 2010).

[37] 75 Fed. Reg. 18576.

Appendix G. Applicability of the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act to Carbon Capture and Storage Activities

The purpose of this paper is to discuss the potential applicability of the National Environmental Policy Act (NEPA), 42 U.S.C. §§ 4321-4370h, the Endangered Species Act (ESA), 16 U.S.C. §§ 1531-1544, and the National Historic Preservation Act (NHPA), 16 U.S.C. §§ 470-470x-6, to CCS activities. This paper also discusses requirements under State NEPA statutes that can affect CCS deployment efforts.

G.1 The National Environmental Policy Act

G.1.1 The Role of NEPA

The two main goals of NEPA are to inject environmental considerations into the Federal agency's decision-making process and to inform the public of the environmental information that a Federal agency has considered.[38,39] NEPA requires agencies to identify and assess alternatives to proposed actions that avoid or mitigate adverse environmental impacts. Thus, NEPA serves as a basis for transparency in Federal government decisions and is an essential part of engaging the public in a collaborative process that ultimately leads to greater public awareness and better agency decisions that reflect an understanding of environmental consequences. The NEPA process provides multiple and meaningful opportunities for public engagement. For example, during the process by which the scope of the issues and alternatives to be examined in an Environmental Assessment or Environmental Impact Statement (EIS) is determined, there can be many public meetings with local communities and stakeholders. Moreover, the public has an opportunity to comment on environmental documents.

G.1.2 Environmental Review is Required when there is a "Major Federal Action"

NEPA requires agencies to prepare an EIS for "every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[40] Although NEPA itself does not define "Federal actions," the regulations promulgated by the Council on Environmental Quality (CEQ) to implement NEPA define a "major Federal action" as an action that is "potentially subject to Federal control and

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[38] *See Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 768 (2004); *Citizens Against Rails-to-Trails v. Surface Transp. Bd.*, 267 F.3d 1144, 1151 (D.C. Cir. 2001).

[39] For more information on the stages of a NEPA analysis, see (see Council on Environmental Quality, 2007).

[40] 42 U.S.C. § 4332(2)(C); *see* 40 C.F.R. § 1502.3.

responsibility."[41] In contrast, where an agency lacks discretion to affect the environmental outcome of its actions, there is no "major Federal action" triggering NEPA.[42]

Although non-Federal projects are normally not subject to NEPA, they *may* be "major Federal actions" if they are "entirely or partly financed, assisted, conducted, regulated, or approved by Federal agencies."[43] Such actions may include approval of specific projects or private actions approved by permit or other regulatory decision.[44] "No litmus test exists to determine what constitutes 'major Federal action.'"[45] Ultimately, for a non-Federal project to become a major Federal action, the Federal agency must have some measure of control over the environmentally pertinent aspects of a non-Federal project, some "ability to influence or control the outcome [of the project] in material respects."[46]

G.1.2.1 Federal CCS Activities That Require Preparation of a NEPA Document

Use of Federal lands for the purposes of CO_2 pipeline siting or storage will require NEPA analysis. The first NEPA analysis that may be considered is a Programmatic Environmental Impact Statement (PEIS) that would analyze the environmental impacts on a region-wide scale for either a pipeline corridor or network, or for regional CO_2 storage. More specifically, CO_2 storage on Federal land will require amendment to the appropriate land use planning documents (i.e., National Forest Plans (Forest Plans) or Bureau of Land Management Resource Management Plans (RMPs)) to allow the use of Federal lands for such purpose. Amendment to Forest Plans or RMPs can be accomplished with a PEIS that would amend all plans within a given region. For example, one NEPA document can be prepared to amend the 11 forest plans applicable to National Forests within the Sierra Nevada mountain range. In some instances, a joint PEIS can be prepared between two or more agencies.[47] As discussed below, consultation under the Endangered Species Act would likely be required for a PEIS, and could be an arduous and time-consuming endeavor where the area of analysis is large. Site-specific analysis under NEPA would still be required for specific pipeline or storage siting, but these site-specific NEPA documents may be somewhat streamlined by being able to "tier" off of the PEIS. The site-specific NEPA documents will evaluate local conditions that might impact local resources, such as endangered or threatened species, requiring consultation under the ESA, or sites on the National Register of Historic Places, requiring analysis under the NHPA.

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[41] 40 C.F.R. § 1508.18. The NEPA regulations further indicate that the term "[m]ajor reinforces but does not have any meaning independent of significantly," id., and thus does not go to whether an action is a "Federal" action triggering an agency's NEPA obligations.

[42] *See Surface Transp. Bd.*, 267 F.3d at 1151 (stating that NEPA is inapplicable if the information NEPA provides can have no affect on the agency's actions).

[43] 40 C.F.R. § 1508.18(a); *Macht v. Skinner*, 916 F.2d 13, 20 (D.C. Cir. 1990).

[44] *See* 40 C.F.R. § 1508.18(b)(4).

[45] *Mineral Policy Ctr. v. Norton*, 292 F. Supp. 2d 30, 54 (D.D.C. 2003) (citation omitted).

[46] *Save Barton Creek v. Federal Hwy. Admin.*, 950 F.2d 1129, 1134 (5th Cir. 1992) (citation omitted); *see also United States v. S. Fla. Water Mgmt. Dist.*, 28 F.3d 1563, 1572 (11th Cir. 1994) ("The touchstone of major Federal activity constitutes a Federal agency's authority to influence non-Federal activity.").

[47] *See (Bureau of Land Management and Forest Service, 2010).*

Conducting a programmatic NEPA analysis is likely to be time-consuming, and that analysis should be commenced very early in the planning process for CCS. In fact, the law directs agencies to integrate the NEPA process into early planning efforts in order that appropriate NEPA analysis is performed and to reduce delay.[48] A PEIS can require two or more years to prepare, and will involve public comment and substantial interagency coordination and analysis. Some examples of timelines for PEIS preparation, from scoping to publication of the Record of Decision, are as follows: 1.5 years for the Geothermal Resources Leasing PEIS (covering 11 western States and Alaska);[49] 1.75 years for the Outer Continental Shelf Alternative Energy PEIS;[50] 2.25 years for the Implementation of a Wind Energy Development Program and Associated Land Use Plan Amendments PEIS (Wind Energy PEIS) (covering 11 western States and amending 52 BLM land use plans);[51] and 3.25 years for the West-wide Energy Corridor PEIS (covering 11 States).[52] Preparation of some PEISs can take close to six years depending on the details covered, the complexity of the program, and the existence of controversy about the program.[53]

Once site-specific projects are identified, NEPA analysis for such a project will require additional time, on the scale of two or more years, depending on the complexity of the project and the significance of the impacts. Preparation of a PEIS can have substantial benefits, however, including streamlined site-specific environmental review, minimization of environmental effects, and better integration with land use plans and other environmental concerns. For example, a PEIS may identify areas of special concern and allow agencies to site pipelines or storage facilities to avoid significant known resources, threatened or endangered species, or other environmental or land use conflicts. A PEIS may also be used to support a program to promote certain policies, develop long-term systematic planning, establish mitigation strategies, and generally set the stage for potential site-specific actions that may have significant environmental impacts.[54]

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[48] 40 C.F.R. § 1501.1(a).

[49] *See* (Bureau of Land Management, 2010b).

[50] *See* (U.S. Department of the Interior, 2010).

[51] *See* (Bureau of Land Management, 2010c).

[52] *See* (Bureau of Land Management et al., 2010).

[53] *See* e.g., (Bureau of Land Management, 2010a).

[54] The Wind Energy PEIS provides an example of how region-wide planning can work to streamline site-specific review:

> [The PEIS]. . . establish[es] policies and BMPs [Best Management Policies] to address the administration of wind energy development activities and identify minimum requirements for mitigation measures. These programmatic policies and BMPs will be applicable to all wind energy development projects on BLM-administered public lands. Site-specific concerns and species-specific concerns, and the development of additional mitigation measures, would be addressed in project-level reviews, including NEPA analyses, as required. To the extent appropriate, future project-specific analyses will tier from the analyses conducted in the PEIS and the decisions in the resultant Record of Decision (ROD) to allow project-specific analyses to focus just on the critical, site-specific issues of concern. In addition, under this alternative, a number of BLM land

If such an analysis is conducted early, it may provide an opportunity to further clarify many of the issues discussed in the present set of reports and analyses. On the other hand, attempting to conduct such an analysis late in the planning process would undercut the utility of the NEPA process and could cause delays in the implementation of CCS.

NEPA review may potentially be streamlined by the use of a categorical exclusion. A categorical exclusion can apply when an agency has determined that certain actions "do not individually or cumulatively have a significant effect."[55] A categorical exclusion, however, does not exempt a project completely from environmental review; an agency still must review for "extraordinary circumstances" that could remove a project from the categorical exclusion if a normally excluded action may have significant environmental effects.[56] At this stage, because of the novelty of many CCS activities, an agency is not likely to have an existing categorical exclusion that could be used. Establishment of a new categorical exclusion by an agency (performed in conjunction with the CEQ) would include developing a basis for the exclusion and gathering information to substantiate it.[57]

G.1.2.2 Private CCS Activities That May Trigger the Federal Government's NEPA Obligations

Private activities may not necessarily be exempt from the NEPA process. A private project that receives some sort of assistance from the Federal government could, in some circumstances, trigger the Federal government's NEPA obligation.[58] Some Federal activities that may trigger the government's NEPA obligations can include providing loans, loan guarantees, grants, or other forms of Federal financial assistance for the design or construction of CCS facilities, approval of permits or rights-of-way for pipeline and/or storage facilities either on Federal or Tribal land held in trust by the United States, approval of a permit required by statute or regulation for CO_2 transport or storage on private land.[59] Additionally, the transfer of land to another entity for the purposes of CCS activities may require NEPA review.

The question of when a private activity becomes "Federalized" (i.e., becomes a major Federal action) is a very complex area of law, and one that is frequently litigated. Ultimately, resolving the question requires a fact-intensive analysis and the question of whether a private project has

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use plans will be amended to address wind energy development, including adoption of the programmatic policies and BMPs and identification of exclusion areas.

(Bureau of Land Management, 2006).

[55] 40 C.F.R. § 1508.4.

[56] Id.

[57] CEQ's draft memorandum provides guidance on applying existing or establishing new categorical exclusions. *See* (Council on Environmental Quality, 2010).

[58] 40 C.F.R. § 1508.18.

[59] Some permitting activities may be exempt from NEPA where a statute or regulation provides for a similar environmental review process and public participation. For example, a Safe Drinking Water Act underground injection control permit for CO_2 storage approved by EPA would not require preparation of a NEPA document by EPA.

become Federalized can turn on very specific circumstances. Therefore, each situation must be evaluated independently. Agencies should carefully consider their involvement in non-Federal projects to determine whether their NEPA obligations may be triggered.

G.1.3 Specific NEPA Considerations for Environmental Review of CCS Projects

Because of the complexity and novelty of CCS, NEPA may present a formidable challenge to agencies in dealing with uncertainty in science and risk assessment, missing information, and consideration of new risks to human welfare or the environment from the deployment of CCS. Potential impacts that may need to be evaluated include: impacts to human and animal life or the environment from the direct release of CO_2 in the air or ocean, impacts to underground water supplies from migration of CO_2, induced seismicity from the storage of CO_2, and impacts to the climate if accidental release occurs. In addition, there will also be challenges in determining the cumulative impacts of CCS projects, what direct and indirect effects are reasonably foreseeable, and the scope of the analysis area. These challenges occur in the context of NEPA's express requirement that the information used to write an EIS must be of high quality and the scientific analysis must be accurate and sound, conditions that can be difficult to attain in the arena of emerging and developing technological systems. Agencies should consider the NEPA document as a way to inform the public on the relative risks and benefits of a new and unfamiliar technology and promote its acceptance. Refusal to address such issues will only serve to undermine the credibility of the agency and the technology.

The CEQ regulations implementing NEPA specify an agency's obligations in the event of incomplete or unavailable information. First, the agency must make it clear that information is lacking. If the missing information is "essential to a reasoned choice among alternatives," an agency must obtain the information unless "the overall costs of obtaining it are exorbitant or the means to obtain it are not known."[60] If the agency cannot obtain the information because it is too costly or the means are unknown, then the agency must include in the NEPA document:

> (1) a statement that such information is incomplete or unavailable; (2) a statement of the relevance of the incomplete or unavailable information to evaluating reasonably foreseeable significant adverse impacts on the human environment; (3) a summary of existing credible scientific evidence which is relevant to evaluating the reasonably foreseeable impacts on the human environment; and (4) the agency's evaluation of such impacts based upon theoretical approaches or research methods generally accepted in the scientific community.[61]

Uncertainty in science and risk assessment may present itself when an agency lacks precise key data or estimates, when there is an incomplete knowledge of system dynamics, or when evaluating the probability of credible catastrophic outcomes. Prior NEPA documents inadequately confronting issues of uncertainty provided a forum to learn from past mistakes and

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[60] *See* 40 C.F.R. § 1502.22.

[61] *Id.* § 1502.22(b).

understand how uncertainty should be honestly assessed not simply for a legally sufficient NEPA document, but also for a NEPA document that will be acceptable to the public.[62] When risk is unclear, there should be a candid discussion of the range of risk and a delineation of the uncertainties. Further, models, their assumptions, and their accuracy should be explained and disclosed. Ultimately, the NEPA document should provide an honest assessment of a projects risks and uncertainties and provide the public with the confidence that regulatory agencies have sufficiently addressed legitimate public concerns.

G.2 The Endangered Species Act

The ESA may also impose certain requirements on CCS development.

G.2.1 The Role of the ESA in CCS

In 1973, Congress enacted the ESA "to provide a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, [and] to provide a program for the conservation of such endangered species and threatened species…."[63]

As relevant to CCS, Section 7 of the ESA outlines the procedures for Federal interagency cooperation to conserve Federally listed species and designated critical habitats. Section 7(a)(1) directs the Secretary (Secretary of the Interior/Secretary of Commerce) to review other programs administered by them and utilize such programs to further the purposes of the ESA. It also directs all other Federal agencies to utilize their authorities in furtherance of the purposes of the ESA by carrying out programs for the conservation of species listed pursuant to the ESA.

Section 7(a)(2) of the ESA requires each Federal agency to ensure that any action authorized, funded, or carried out by that agency "is not likely to jeopardize the continued existence of any endangered species or threatened species" or "result in the destruction or adverse modification" of designated critical habitat.[64] To achieve this objective, the agency proposing the action is required to consult with the U.S. Fish and Wildlife Service (USFWS) or the National Marine Fisheries Service (NMFS) (collectively, the Services) whenever a Federal action "may affect" a threatened or endangered species.[65] In fulfilling these requirements, each agency must use the best scientific and commercial data available.[66]

G.2.2 Consultation is Required when there is a "May Affect" Determination

ESA consultation will be determined by the presence of endangered or threatened species in specific project areas. If a determination is made that the action "may affect" listed species, the action agency must pursue some form of consultation ("informal" or "formal") with either the

[62] For a full discussion, *see* (Farber, 2009).

[63] 16 U.S.C. § 1531(b).

[64] 16 U.S.C. § 1536(a)(2).

[65] 50 C.F.R. § 402.14(a).

[66] 16 U.S.C. § 1536(a)(2).

Service or NMFS depending on the species involved. The action agency may prepare a biological assessment (BA) to evaluate the potential effects of a proposed action.[67]

BAs are required if an agency is proposing to engage in a "major construction activity,"[68] although agencies often prepare them voluntarily as a convenient mechanism to facilitate the consultation.

As part of a formal consultation process, the consulting agency will issue a biological opinion detailing how the proposed action will affect the listed species.[69]

If the USFWS or NMFS determines that the proposed action is likely to jeopardize the species, it must develop reasonable and prudent alternative actions that the Services believe the agency or the applicant may take to avoid the likelihood of jeopardy to the species or destruction or adverse modification of designated critical habitat.[70]

If the USFWS or NMFS determines that the proposed action—whether standing alone or as modified by a reasonable and prudent alternative—is not likely to jeopardize the species, but may result in the incidental "take"[71] of individuals of the species, the consulting agency provides an incidental take statement (ITS) along with the biological opinion.[72] The ITS must specify the impact of the incidental taking on the species and specify those reasonable and prudent measures that the USFWS or NMFS considers "necessary or appropriate to minimize such impact."[73] "[A]ny taking that is in compliance with the terms and conditions specified in a written [ITS]... shall not be considered to be a prohibited taking of the species concerned."[74]

G.2.2.1 Federal CCS Activities That Require Preparation of an ESA Document

Where there is an effect on ESA listed species, use of Federal lands for the purposes of CO_2 pipeline siting or storage requires ESA consultation, which can be undertaken in conjunction with NEPA obligations. The use of programmatic consultations, however, described in subsection A.2.i. above, may present additional challenges in the ESA context. As opposed to individual, site-specific projects, a programmatic plan, for example, establishing a national plan for the development of CCS infrastructure, would involve an "action" that is extremely broad. Moreover, concrete and on-the-ground effects would not be readily apparent or even existent until particular projects or actions are proposed pursuant to the programmatic decision. Thus, the effects of the action—which may cover the entire United States—may be difficult to assess

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[67] 50 C.F.R. § 402.12(a).

[68] 50 C.F.R. § 402.12(b).

[69] 16 U.S.C. § 1536(b)(3)(A).

[70] 50 C.F.R § 402.14(h)(3).

[71] The term "take" means to "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct." 16 U.S.C. § 1532(19).

[72] 16 U.S.C. § 1536(b)(4)(i)-(ii).

[73] *Id.*

[74] *Id.* at § 1536(o)(2).

at a level that is more than theoretical and speculative. The precise circumstances in which ESA consultation is required in such contexts are not entirely clear, but courts have required consultation and issuance of an ITS in some situations.[75] If a programmatic consultation is undertaken, site-specific consultations, as in the NEPA context, may be somewhat more efficient by being able to be tiered off of the programmatic consultation documents.

As with NEPA, obligations under the ESA may vary depending on the level of Federal involvement, and whether the agency has any discretion, pursuant to a relevant statute, to take measures to benefit the protected species.[76] Even if the government has sufficient discretion, where projects involve non-Federal actors, the issue would be whether Federal participation transforms a project into a Federal action. This matter is complex and is frequently litigated; a court has said that it "is simply one of degree,"[77] but the relevant analysis is not always straightforward. One key element is the degree of the Federal agency's control over the environmentally pertinent aspects of the project to require ESA consultation.[78]

G.2.3 Private CCS Activities That Trigger the Government's ESA Obligations

For ESA consulting responsibilities to be triggered, there also would have to be a causal link between an agency's decisions and effects to listed species. While the ESA Section 7(a)(2) does not require Federal agencies to protect listed species or critical habitat from harms caused by third-party actors, seemingly private activities may not be exempt from the ESA.

That said, private activities that could trigger the government's ESA obligation would be similar to the triggers in a NEPA context: where the government providing loans, loan guarantees, grants, or other forms of Federal financial assistance for the design or construction of CCS

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[75] *See Center for Biological Diversity v. FWS*, 623 F. Supp. 2d 1044, 1053 (N.D. Cal. 2009) (holding that "a programmatic forest plan does have an effect upon subsequent land use decisions and therefore upon the land itself," and thus is the cause of incidental take that must be covered by an ITS); *see also Natural Resources Def. Council v. Evans*, 364 F. Supp. 2d 1129 (N.D. Cal. 2003) (holding that NMFS was required to issue an ITS in a programmatic consultation on the Navy's potential use of sonar in as much as 75 percent of the world's oceans); *but see Western Watersheds Project v. BLM*, 552 F. Supp. 2d 1113 (D. Nev. 2008) (upholding FWS programmatic BiOp and finding "no error in the failure of [FWS] to issue an ITS"); *Arizona Cattle Growers Ass'n v. FWS*, 273 F.3d 1229, 1233 (9th Cir. 2001) (rejecting the notion that an ITS must accompany every BiOp and holding instead that "an Incidental Take Statement must be predicated on a finding of incidental take").

[76] An agency is required to consult only on actions where it has discretion to implement measures that inure to the benefit of protected species. The purposes underlying the relevant statute must allow the agency to consider protected species. *National Ass'n of Home Builders (NAHB) v. Defenders of Wildlife*, 551 U.S. 644, 671-72 (2007); *Turtle Island Restoration Network v. Nat'l Marine Fisheries Service*, 340 F.3d 969, 975 (9th Cir. 2003). In other words, the consultation requirement of Section 7(a)(2) of the ESA "covers only discretionary agency actions and does not attach to actions . . . that an agency is required by statute to undertake once certain specified triggering events have occurred." *NAHB*, 551 U.S. at 669. Accordingly, if a new CCS statute dictated that a Federal agency's only role in reviewing CCS permit applications was to ensure certain criteria were met, and the government had no discretion, ESA consulting obligations would be less likely to apply.

[77] *Ka Makani 'O Kohala Ohana, Inc. v. Water Supply*, 295 F.3d 955, 960 (9th Cir. 2002) (citation omitted).

[78] *See Sierra Club v. Babbitt*, 65 F.3d 1502, 1512 (9th Cir. 1995) (ESA not triggered where Bureau of Land Management could not control development activity under a right-of-way agreement).

facilities; approval of a permit or right-of-way for pipeline and/or storage facilities either on Federal or Tribal land held in trust by the United States; or CO_2 transport or storage on private land if a permit is required by statute or regulation for such activities).

Finally, the ESA also imposes certain requirements on private actors. For example, the Act makes it unlawful for anyone, including a private party, to "take" any species listed under the act without first obtaining a permit.[79] Therefore, even if a CCS project were to be found not to impose Section 7(a)(2) Federal consultation requirements, a private developer would likely still consider a project's potential effects on any listed species as part of its planning.

G.2.4 Specific ESA Considerations for Environmental Review of CCS Projects

As detailed above, the complexity and novelty of CCS may present a formidable challenge to agencies in dealing with uncertainty in science and risk assessment, missing information, and consideration of new risks to human welfare or the environment from the deployment of CCS.

Under the ESA, however, the government cannot await perfect information, but must act instead upon "the best scientific and commercial data available."[80]

To that end, the presence of scientific uncertainty, or the fact that evidence may be "weak," is not fatal to an agency's consultation decision.[81] Here, the government would need to evaluate even "novel" harms that may befall threatened and endangered species.[82] As with NEPA, evaluating these uncertainties and risks and informing decision makers and the public may be challenging; however, the ESA imposes substantive requirements to avoid likely jeopardy to listed species and the adverse modification of critical habitat, and the refusal to address novel issues will leave actions vulnerable to legal attack and remand.

With this in mind, the above NEPA considerations regarding the uncertainty in science and risk assessment should apply to ESA consultation (where necessary) as well. The use and limits of available science should be explained and disclosed. Assumptions should be supported, and the agency should discuss whether other models or other assumptions lead to different conclusions. Ultimately, as with the NEPA document, an ESA consultation should provide an honest assessment of a project's risks and uncertainties.

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[79] 16 U.S.C. § 1538.

[80] *Building Indus. Ass'n v. Norton*, 247 F.3d 1241, 1246 (D.C. Cir. 2001) ("the Service must utilize the 'best scientific … data available,' not the best scientific data possible.").

[81] *Greenpeace Action v. Franklin*, 14 F.3d 1324, 1337 (9th Cir. 1992) (upholding biological opinion, despite uncertainty about the effectiveness of management measures, because decision based on a reasonable evaluation of all available data).

[82] However, a causal connection, either directly or indirectly, between the proposed agency action and the effect on a listed species must be established. See National Wildlife Federation v. NMFS, 524 F.3d 917, 930 (9th Cir. 2008); Arizona Cattle Growers' Association v. USFWS,273 F.3d 1229 (9th Cir. 2001).

G.3 Other Federal Regulatory Requirements

CCS activities may trigger other Federal requirements. For example, the National Historic Preservation Act, similar to NEPA, requires Federal agencies to evaluate the impact of Federal actions on sites listed on, or eligible for, the National Register of Historic Places.[83]

G.4 State NEPAs

Fifteen States have enacted environmental policy acts similar to the Federal NEPA.[84] While the Federal NEPA is procedural in nature, a number of State counterparts impose substantive requirements. For example, the California Environmental Policy Act requires that public agencies not approve projects if there are "feasible" alternatives; i.e., if the alternatives are "capable of being accomplished in a successful manner in a reasonable period of time, taking into account economic, environmental, social, and technological factors."[85] Moreover, different types of State action trigger the State NEPA process, and the particular State agencies covered by the legislation vary.[86] Because currently CO_2 pipeline and siting decisions are authorized and permitted by States, environmental review through various State NEPAs more frequently occurs than Federal NEPA review. If CCS becomes a project national in scope (i.e., through inter-state pipelines), a uniform environmental review process may be more desirable.

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[83] 16 U.S.C. §§ 470-470a-2.

[84] Arkansas, Ark. Stat. Ann. § 8-1-101; California, Cal. Pub. Res. Code §§ 21000 et seq.; Connecticut, Conn. Gen. Stat. Ann. §§ 22a-14 *et seq*.; Florida, Fla. Stat. §§ 380.92 *et seq*.; Hawaii, Haw. Rev. Stat. §§ 343-1 *et seq*.; Indiana, Ind. Code Ann., §§ 6-981 *et seq*.; Maryland, Md. Nat. Res. Code Ann. §§ 1-301 *et seq*.; Massachusetts, Mass. Gen. Laws Ann. ch. 30, §§ 61 *et seq*.; Minnesota, Minn. Stat. Ann. §§ 116D.01 *et seq*.; Montana, Mont. Code Ann. §§ 75-1-101 *et seq*.; New York, N.Y. Envtl. Conserv. Law §§ 8-0101 *et seq*.; North Carolina, N.C. Gen. Stat. §§ 113A-1 *et seq*.; South Dakota, S.D. Codified Laws Ann. §§ 34A-9-1 *et seq*.; Virginia, Va. Code §§ 10.1-1200 *et seq*.; Washington, Wash. Rev. Code §§ 43-21C.010 *et seq*.

[85] Cal. Pub. Res. Code, § 21061.1.

[86] *See* Daniel Mandelker, NEPA Law and Litigation, § 12.01 (2d. ed. 1984).

Appendix H. Potential Causes of Long-Term Storage Risk and/or Liability

Potential causes of long-term storage and/or liability risk include the following:

1. **Scientifically understood phenomena**. For example, migration of CO_2 in scientifically understood ways as a result of high injection pressures.
2. **Scientific uncertainties or unknown phenomena** that would alter previous understandings about risks.
3. **Operator error**. For example, an operator misapplies monitoring technology and fails to detect migration of CO_2, or an operator misuses injection equipment, which fails, and CO_2 is released from the storage site.
4. **Regulatory mistake or oversight.** For example, a State or Federal agency reviewing a permit application fails to detect a geological feature, or fails to identify migration of CO_2 in monitoring data.
5. **Falsification and illegal conduct**. For examples, a site operator falsifies geological data in order to obtain a permit; a site operator falsifies monitoring data in order to avoid the costs of remediation; or a site operator stores more CO_2 than allowed under a permit to obtain the associated income stream.
6. **Policy changes**. For example, a subsequent Administration withdraws funding for CCS activities, or the relevant legal framework changes, or a State ceases funding for a storage site.
7. **Acts of God**. For example, an earthquake causes a release from a storage site.
8. **Judicial system error**. For example, groundwater contamination develops near a storage site. The harm is not in fact caused by the site, but would have occurred even without the storage activity. A court nevertheless erroneously holds the site operator liable, for example on an ultrahazardous activity theory.

Scope of this list. Note that the foregoing list of sources of long-term storage risk and/or liability only addresses risks and/or liabilities associated with storage activities. Capture and transportation risks are not included. Certain "garden variety" sources of risks associated with industrial activities that will occur at a storage site—such as injuries at the surface facility—are also excluded.

Appendix I. Price-Anderson Act Private Insurance Program

The Price-Anderson Act (PAA) includes a private insurance program that may be adapted (with appropriate revisions) for insuring the risks of long-term storage of CO_2 from CCS activities. It should be noted, however, that the main incentive for private insurers to offer the insurance mandated by the PAA may be the fact that the PAA caps the liability of nuclear plant operators at an amount equal to the limits of liability under applicable insurance policies.

Under the PAA, the nuclear energy industry provides more than $10 billion in insurance coverage in the event of a nuclear incident. No portion is borne by the taxpayers or the Federal government. However, public utilities that operate nuclear reactors will generally be permitted by their regulators to include the cost of these insurance premiums in the costs of service borne by ratepayers. The PAA private insurance protection consists of two tiers:

1. The primary level provides $375 million in liability insurance. This first-level coverage consists of the liability insurance provided by insurance pools. The pools are groups of insurance companies pledging assets that enable them to provide substantially higher coverage than an individual company could offer. If this amount is not sufficient to cover claims arising from a nuclear incident, secondary financial protection applies.

2. For the second level, in the event of a nuclear incident, each nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum premium of $117.5 million. In any single year, however, the premium for the second tier is capped at a ceiling set by the NRC; currently, that annual cap is $17 million per incident. All 104 operating nuclear reactors in the United States are participating in the secondary financial protection program.

If claims exceed the maximum Price-Anderson value (i.e., insurance coverage is exhausted), the private insurers have no further liability. In that event, the President is required to submit proposals to Congress. These proposals must detail the costs of the incident, recommend how funds should be raised, and detail plans for full and prompt compensation to those affected. If Congress fails to provide for compensation, claims can be made under the Tucker Act (in which the government waives its sovereign immunity), 28 USC § 1491, for failure by the Federal government to carry out its duty to compensate claimants.

The NRC codifies the conditions for indemnity agreements, liability limits, and fees for the different classes of licensees in 10 C.F.R. § 140. Power reactors rated below 100 MWe, for example, have lower primary insurance requirements than larger reactors, while the financial protection required for nonprofit educational reactors is a function of their maximum power and the neighboring population.

Appendix J. Governmental Indemnification

The option of governmental indemnification is characterized by several legal and policy infirmities. First, as a matter of law, the United States may not agree to open-ended indemnification arrangements absent specific Congressional authorization. *See* Anti-Deficiency Act, 31 U.S.C. 1341(a)(1)(B). Such authorizations have rarely been granted because open-ended indemnification agreements by the United States could be very costly. Only in the most exceptional and necessary circumstances has such authorization been given. Given this past experience, it is doubtful that the circumstances surrounding CCS warrant this extraordinary step.

Second, sound public policy and legislative precedent counsel that authority to indemnify should be strictly limited to activities of absolutely vital national security interests (military or otherwise) and then only when private insurance is unavailable. Authority to enter into open-ended indemnification agreements with contractors and other third parties generally has been narrowly confined to those areas in which procuring the goods or services has been deemed essential to the national defense, and private insurance cannot be obtained to protect against the potential liability (e.g., agreements indemnifying Department of Energy contractors for liability arising out of nuclear incidents, agreements indemnifying certain Department of Defense contractors). *See* Pub. L. 85-804 (codified as 50 U.S.C. § 1431-1435);[87] the Price-Anderson Act, 42 U.S.C. § 2210; and, generally, the discussion in *Hercules Inc. v. United States*, 516 U.S. 417, 426-29 & n.11 (1996).

Underlying these legislative exceptions and their implementing regulations has been the premise that not only is the activity essential to national security, but also that private markets cannot provide adequate insurance coverage in the event of a disaster. Executive Order 11610, which supplements Executive Order 10789 and further implements Public Law 85-804, instructs that:

> [i]n deciding whether to approve the use of an indemnification provision and in determining the amount of financial protection to be provided and maintained by the indemnified contractor, the appropriate official shall take into account such factors as the availability, cost and terms of private insurance, self-insurance, other proof of financial responsibility and workmen's compensation insurance. Exec. Order No. 11,610.

J.1 Price Anderson Act Indemnification Provisions

The Price-Anderson Act has two components: an insurance component that is discussed in Appendix I and an indemnification component that is discussed here.

[87] Pursuant to Public Law 85-804 and Executive Order 10789, the Federal Acquisition Regulations (FAR) provide detailed requirements that must be met when a government contractor seeks indemnification agreements. See FAR Extraordinary Contractual Actions Subpart 50.1, 48 C.F.R. pt. 50.1including C.F.R. § 50.104-3 (Special procedures for unusually hazardous or nuclear risks). *See also*, FAR Contracts with Commercial Organizations Subpart 31.2, 48 C.F.R. pt. 31.2; 48 C.F.R. § 31.205-19(e)(5); and FAR Indemnification Under Public Law 85-80448 C.F.R. § 52.250-1.

One approach to government indemnification is contained in a portion of the PAA dealing with the potential liability of public sector employees and private sector contractors who have been engaged by the DOE to conduct decommissioning and clean-up operations on former defense, government-owned sites. The PAA requires the Secretary to enter into indemnification agreements with any person who may conduct “activities” under a contract with DOE that involves risk of “public liability.” Both of these terms are broadly defined.

The PAA indemnity applies to all contracts entered into with DOE involving a radiological risk. It covers both lump sum and cost-reimbursement type contracts, and includes contracts and projects financed in whole or in part by DOE. The indemnity applies regardless of where the activities occur, and covers a broad spectrum of activities ranging from contractors engaged in clean-up activities on a designated site to transporting nuclear materials to or from a site. It is enforced by means of a standard form indemnity clause incorporated into any applicable DOE contract.

The indemnity expressly covers all claims for “public liability” within the meaning of the PAA, together with the contractor's legal costs and other costs covered up to a specified maximum amount. Coverage under the indemnity is automatically extended to any subcontractors engaged by the contractor, by means of a provision in the indemnity requiring the contractor to provide an equivalent indemnity in any contract that the contractor enters into with a subcontractor.

“Public liability” is broadly defined in the PAA but does include some exceptions. Claims of employees of the contractor who are employed at the site of, and in connection with, the activity where the nuclear incident occurs who are covered by State or Federal workers’ compensation acts are not covered. There is also no right of recovery where a nuclear incident results from “acts of war,” and there is typically no carve-out under the indemnity for the contractor's negligence, willful or reckless misconduct. Thus contractors can benefit from protection regardless of fault.

J.2 Indemnification History

A number of claims have been filed in Federal district courts seeking recovery under the PAA since its 1988 amendments. Settlements have been paid in two cases that arose out of activities at the DOE Feed Material Production Center (FMPC) in Fernald, Ohio, conducted from the 1950s to the 1980s. The cases were brought in the United States District Court for the Southern District of Ohio.

In re Fernald Litigation was brought in 1985 by property owners and residents living near the facility and local businesses and their employees (excluding employees of the DOE facility contractor). Plaintiffs alleged causes of action for negligence, strict liability, private nuisance, willful and wanton misconduct, violation of the parent corporation’s contractual guaranty and violation of the PAA. Plaintiffs claimed damages for emotional distress and diminution in property values. The parties participated in a summary jury trial in 1989 in which the jury returned a verdict for the plaintiffs for $136 million, including $1 million for diminution in property, $80 million for a medical monitoring fund, and $55 million in punitive damages. The parties reached a settlement for $78 million that was paid by DOE. The DOE indemnity was cited as the authority for payment of the settlement. *See In re Fernald Litigation*, No. C-1-85-149, 1989 WL 267039 (S.D. Ohio Sept. 29, 1989).

Day v. NLO, Inc. was filed in 1990 by workers and frequent visitors of the FMPC facility. Some of the plaintiffs' claims were dismissed because workers' compensation provided the exclusive remedy for these claims. The court concluded that its jurisdiction to hear this case stemmed from the PAA and that the Act was the source of all the plaintiff's claims. DOE eventually paid $20 million to settle this lawsuit. *See Day v. NLO, Inc.*, 811 F. Supp. 1271 (S.D. Ohio 1992).

J.3 Underlying Policy on Open-Ended Indemnification

An open-ended indemnification approach is very dangerous, since it does not deal in any way with the "moral hazard" issue, and simply shifts all risks to Federal taxpayers.

The Executive Branch's longstanding view has been that waivers of the strictures of the Anti-Deficiency Act should only be considered (and not necessarily approved) in situations in which essential activity will simply not be conducted absent a governmental agreement to indemnify. Further, our view has been that if there are to be agreements to indemnify, they should be governed by the constraints placed on contractors in the national defense arena, as set forth above.[88] In addition, it would make sense for any indemnification to contain a sunset date or provide that the authority to develop indemnity agreements should expire on a date certain absent reauthorization, as in the PAA context. This would allow Congress to evaluate the continuing need for indemnity agreements based on the current state of the commercial CO_2 capture and storage market and availability of private insurance. Additionally, to protect the public, individual indemnification agreements should be subject to DOJ review.[89]

[88] The sorts of indemnification proposals that have been made thus far have defined "liability" that would trigger indemnification as essentially any harm to persons, property, or natural resources. Such an indemnity would not be limited to hazards unique to the CO_2 capture and sequestration program; it could apply to injuries such as caused by traffic accidents in the course of the operations. Thus, any indemnification program should be limited to hazards unique to the program. There is also the potential that indemnity arrangements could be read to provide indemnification from natural resource damage claims by Federal trustees under section 107 of the Comprehensive Environmental Response, Compensation, and Liability Act (Superfund), 42 U.S.C. § 9607. This would be inconsistent with section 107(e), which prohibits indemnity agreements for actions under section 107.

[89] Section 330 of the National Defense Authorization Act of 1993, 10 U.S.C. § 2687 note (known as Section 330), provides that "the Secretary of Defense shall hold harmless, defend, and indemnify in full [certain] persons and entities . . . from and against any suit, claim, demand or action, liability, judgment, cost or other fee arising out of any claim for personal injury or property damage . . . that results from, or is in any manner predicated upon, the release or threatened release of any hazardous substance, pollutant or contaminant, or petroleum or petroleum derivative as a result of Department of Defense activities at any military installation (or portion thereof) that is closed pursuant to a base closure law.@ Pub. L. 102-484, Div. A, Title III, § 330, 106 Stat. 2371 (1992) (codified at 10 U.S.C. § 2687). This provision does not require the putative indemnitee to go through processes like those under Public Law 85-804. While Section 330 is precedent for blanket statutory indemnification, such steps should not be taken lightly or routinely. The legislative proposals offered last year in Congress did not provide a blanket statutory indemnification, but, rather simply would authorize the Secretary of Energy to enter into indemnification agreements.

Appendix K. Liability Associated with DOE CCS RD&D Programs

DOE is engaged in several programs aimed at promoting clean coal technologies and CCS. The major efforts include the Regional Carbon Sequestration Partnerships (RCSP), the Clean Coal Power Initiative (CCPI), and FutureGen. Liability issues associated with the current DOE clean coal programs are generally handled pursuant to existing Federal and State laws.

RCSP and CCPI Liability Issues. DOE thus far has not taken a property interest in any of the projects that it has funded through the RCSPs or CCPI programs, and it has offered funding under these two programs on the condition that it would be indemnified by funding recipients for any potential liabilities associated with CO_2 from project operations. For example, DOE application materials for the RCSPs contain language disclaiming DOE responsibility for liability associated with project activities. Similarly, DOE issued CCPI model cooperative agreements that went out with the last round of Funding Opportunity Announcements (FOAs) in 2009 with the following notification:

> INDEMNITY The Recipient shall indemnify the Government and its officers, agents, or employees for any and all liability, including litigation expenses and attorneys' fees, arising from suits, actions, or claims of any character for death, bodily injury, or loss of or damage to property or to the environment, resulting from the project, except to the extent that such liability results from the direct fault or negligence of Government officers, agents or employees, or to the extent such liability may be covered by applicable allowable costs provisions.

FutureGen Liability Issues. Liability issues associated with FutureGen are governed by a specific State law, the Clean Coal FutureGen for Illinois Act, 20 Ill. Comp. Stat. 1107/1 *et seq.* (2007) (CCFI). Provided that the FutureGen plant is located at one of two locations in Illinois (Tuscola or Mattoon, IL), CCFI provides for the transfer of title to and any liabilities associated with stored gas to the State. Title to and any liabilities associated with pre-injection stored gas remains with the operator of the FutureGen plant. CCFI also directs the State Department of Commerce and Economic Opportunity to procure insurance from a private insurance company, “if and to the extent such a policy is available,” that insures the operator of the FutureGen plant against any qualified loss from a “public liability” action. “Public Liability” is defined in CCFI as “any civil legal liability arising out of or resulting from the storage, escape, release, or migration of the post-injection stored gas that was injected during the operation of the FutureGen Project by the FutureGen Alliance,” but does not include any legal liability arising out of or resulting from the construction, operation, or other pre-injection activity of the operator. In addition to requiring insurance paid by State funds to protect the plant operator, CCFI contains a requirement that the State indemnify the plant operator against the risks of public liability actions except where the operator has engaged in intentional or willful misconduct; the operator has failed to comply with applicable Federal or State laws, rules, or regulations for CCS; the liability relates to pre-injection operations; or the loss has been covered by insurance. The obligations to obtain insurance and to indemnify the plant operator will be reduced under CCFI to the extent the State is indemnified by the Federal government.

Appendix L. Property Rights

L.1 Aggregation of Pore Space

Ideally, pore space could be acquired through an agreement with a single owner who owns all surface and subsurface rights. However, issues may arise where pore space needs for CO_2 storage extend over an area where numerous owners hold rights.

Several options could address aggregation of pore space for CO_2 storage projects. All options except the first would require a statutory change or regulatory authorization.

Option 1: Rely on Private Commercial Transactions. As noted in Section III, one option would be for owner-operators to engage in private commercial transactions with property owners to acquire ownership of or lease the pore space. A variation on this approach would be for the Federal government to engage in private commercial transactions to acquire pore space, but there could be Comprehensive Environmental Response, Compensation, and Liability Act and/or tort law implications where ownership vests in a government entity.

Option 2: Exercise or Delegate Federal and/or State Eminent Domain Authority. Federal or State governments could use (or delegate) their authority of eminent domain to condemn pore space for use for a CO_2 storage project. Eminent domain is used to acquire property rights for underground natural gas storage in several States and under the Federal Natural Gas Act (NGA) (Anderson, 2009).[90] The use of condemnation would assist projects in moving forward where hold-out property owners exist or where the sheer number of property owners makes private commercial transactions to acquire ownership or access difficult (Anderson, 2009). The exercise of eminent domain would require an award of just compensation. In addition, there could be CERCLA and/or tort law implications where ownership vests in a government entity.

Option 3: Enable Unitization of Pore Space. Unitization of pore space would permit separate owners of pore space within a geological formation to act as a single unit for CO_2 geologic storage. Unitization is commonly used for secondary recovery of oil (Wilson and de Figueiredo, 2006), where oil and gas leases are combined in a single unit to increase the efficiency of production. Members of the unit are compensated, usually from production or rental revenues (Klass and Wilson, 2010). Unitization of pore space could build on established standards for oil field unitization. Unitization could be compelled when a minority group of owners objects to the use of their interests in the pore space. However, there would need to be a mechanism for compensating members of the unit, such as injection revenues and/or revenues from a future carbon credit market (Sorensen et al., 2009).

Option 4: Provide Pore Space Underlying Onshore or Offshore Federal Lands for CO_2 Storage. The Federal government could make pore space underlying Federal lands available for CO_2 storage. Where the Federal government owns all land rights ("in fee simple"), conflicts regarding ownership of pore space are less likely to occur. However, property rights disputes could arise if injected CO_2 migrates beyond the Federal property boundary, or if

[90] 15 U.S.C. § 717f.

ownership rights in the surface and minerals have been split between the Federal government and private entities. Conflicts with other surface and subsurface competing uses may occur such as mining, recreation, grazing, water production, cultural resource protection, and community growth and development. There may also be additional requirements associated with projects taking place on Federal lands, including under NEPA (see Section IV.B.1.1). Notwithstanding these concerns, use of onshore or offshore Federal lands may be a viable option for some near-term CO_2 storage projects.

Options 5: Assert that No State and/or Private Property Interest Exists in Deep Pore Space.[91] The United States could assert that no private property interest exists in deep pore space and that pore space property rights are owned by the Federal government. One could make an argument that sovereignty over navigable waterways provides precedent for Federally owned property interests. However, except in those instances where a property right has been recognized in the common law as belonging to the Federal government, the determination of property rights traditionally is reserved to the States, and the case could be made that the role of determining pore space ownership should remain with the States. In addition, the assertion of Federal government ownership would undermine State efforts to determine pore space property rights. Assigning pore space ownership to the government with the predetermined notion that the space is designated for storage of CO_2 could also discourage the consideration of alternative uses of the subsurface. In addition, there could be CERCLA and/or tort law implications where ownership vests in a government entity. Finally, one might expect constitutional challenges associated with this option.

L.2 Valuation

At present, it is difficult to estimate a market price for pore space because demand is limited, resulting in few sales that might provide representative prices. The transactions that do occur depend on the ability of purchasers to persuade owners to sell or lease. A Federal carbon emissions reduction program that led to large-scale CO_2 storage would increase demand for pore space markedly, and could lead to an increase in property values. Additional sellers might enter the market in response to such demand, but continued reliance on voluntary sales or leases could elevate prices. Congress might increase availability of privately owned pore space, while also strengthening purchasers' negotiating posture, by authorizing acquisition via condemnation. As noted above, eminent domain authority could be exercised by a Federal agency tasked by Congress with acquiring rights in privately owned pore space, or delegated to CO_2 storage operators or other agents in procedures akin to those used under the NGA.[92] At the outset, pore space owners might challenge condemnation by alleging that acquisition for CO_2 storage by private operators is not a "public" use; however, such challenges would almost surely fail under precedent established by the NGA and relevant Supreme Court decisions.[93]

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[91] *See*, e.g., (RFF, 2007; CCS Regulatory Project, 2008).

[92] 15 U.S.C. § 717f.

[93] Hawaii Housing Authority v. Midkiff, 467 U.S. 229 (1984); Kelo v. City of New London, 545 U.S. 469 (2005).

If eminent domain authority is made available, the Fifth Amendment mandate for payment of just compensation will apply.[94] Just compensation has historically been computed as the market value of a property interest on the date it is appropriated.[95] In turn, market value is defined for Federal takings as the amount in cash, or on terms reasonably equivalent to cash, for which in all probability a property would have sold after a reasonable exposure time in an open competitive market, from a willing and reasonably knowledgeable seller to a willing and reasonably knowledgeable buyer, with neither acting under any compulsion to buy or sell, giving due consideration to all available economic uses of the property.[96]

In other words, if there is a prevailing market price at the time of a taking, that price is likely to be deemed just compensation. However, assessing the market value of any property interest can be difficult where, as with pore space, there are few transactions to analyze. That issue has arisen in eminent domain actions brought under the NGA to acquire subsurface gas storage rights. In at least one NGA case,[97] a Federal court applied State law governing just compensation rather than Federal standards. Choice of State law valuation standards may open the door to higher values than would application of Federal standards, as well as inconsistent valuations across multiple States.[98]

Where evidence of comparable sales or leases of pore space is unavailable, parties will look to other factors to establish just compensation. For example, an owner might offer proof of loss in the overall value of its entire property interest caused by the taking of the pore space. Ultimately, to the extent that CO_2 storage is sought in private subsurface areas where there are already commercial uses of pore space, such as for natural gas storage, the costs of obtaining rights to the subsurface may be more easily estimated. In other cases, where a geologic formation is appropriate for CO_2 storage but there are not other commercial uses for the pore space, the costs associated with acquiring that property may be difficult to quantify until enough comparable transactions have taken place to establish a going price in the market.

L.3 Takings Implications

As discussed above, a determination must be made as to who owns the pore space that is being used for storage of CO_2. While most legal authority generally suggests that ownership of the pore space belongs to the surface estate holder,[99] the ultimate determination of ownership for any specific property must turn on the application of State property law to the specific terms of

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[94] [N]or shall private property be taken for public use, without just compensation. U.S. Const. Amend. V.

[95] E.g., Kirby Forest Industries, Inc. v. United States, 467 U.S. 1 (1984).

[96] Uniform Appraisal Standards for Federal Land Acquisitions, Section B-2 (Appraisal Institute, 5th ed. 2001), available online at http://www.justice.gov/enrd/land-ack/Land_acquisition.html. This definition is based on a compendium of Supreme Court decisions cited therein.

[97] Columbia Gas Transmission Corp. v. Exclusive Natural Gas Storage Easement, 962 F.2d 1192 (6th Cir. 1992).

[98] State compensation standards sometimes permit more generous landowner recovery by requiring payment for elements of damage not compensable under Federal law.

[99] See, e.g., Emeny v. United States, 412 F.2d 1319 (Ct. Cl. 1969) (government's ownership of gas rights under privately-owned surface did not entitle government to inject and store helium within pore space).

any applicable title documents.[100] As very few States have addressed pore space ownership either through statutory or case law, it may be advisable to institute legal proceedings to resolve disputes in advance of commencing CO_2 storage. Where the United States asserts that it is the title holder to the pore space, such litigation may be brought in Federal district court pursuant to 28 U.S.C. § 2509a.

By confirming through the judicial system that it is the rightful owner of pore space, the United States could avoid claims against it by competing owners based on the Fifth Amendment. That section of the United States Constitution provides that private property shall not be taken by the United States for public use without the payment of just compensation. It is well established that the permanent occupation of private property by the United States establishes a successful "physical takings" claim, which although not precluding continuation of CO_2 storage activities, would require the United States to compensate the owner of the pore space for the market value of the occupied property interest.

Fifth Amendment takings claims also could arise as a result of restrictions imposed by the Federal government on property interests adjacent to Federally held pore space. For example, where a private party holds the right to extract minerals from a stratum beneath the pore space, it may be necessary to preclude mining of those minerals so as to ensure the structural integrity of the CO_2 storage area. Such restrictions could give rise to "regulatory takings" claims by the holder of the deeper mineral interests. Like physical takings, regulatory takings entitle a successful claimant to just compensation based on the market value of the property interest; the determination of liability is far more complex, however, requiring a balancing of the property owner's investment-backed expectations, the character of the government action, and the economic impact.

[100] In the case of Federal lands, interpretation of a Federal patent is a matter of Federal law. See Bourgeois v. United States, 545 F.2d 727 (Ct. Claims 1976), and Borax Consolidated Ltd. v. Los Angeles, 296 U.S. 10, 22 (1922).

Appendix M. Siting Considerations for CO_2 Pipelines

M.1 Siting of Pipelines across Private Lands

Given the potential for expansion of interstate and intrastate CO_2 pipelines and storage facilities, revisiting the siting authority of CO_2 pipelines across private lands may be warranted. Three potential models are discussed below.

Model 1: No Federal Authority – Retain Status Quo. This approach would retain existing State or local siting of CO_2 infrastructure. Various States have sited approximately 3,600 miles of CO_2 pipeline in the United States (Dooley, 2008). There have been no instances of complaints that States have either inappropriately denied requests for CO_2 pipelines or unduly delayed projects. However, the existing system of CO_2 pipelines is relatively limited. The largest existing CO_2 pipeline system is located in and around the Permian Basin of Texas, Colorado, Oklahoma, and New Mexico. The on-shore oil pipeline network, which has also been developed without Federal siting authority, is much more extensive, but still does not approach the level of development of the existing interstate natural gas pipeline network, which has been Federally sited since 1938. A State siting approach for CO_2 infrastructure may prove to be effective to the extent that a substantial, long-line, interstate pipeline network is not required.

However, if an extensive network of long-line interstate pipelines is needed for transporting CO_2, the State siting approach could prove to be complex and expensive. The differing siting and permitting requirements among the various States could lead to coordination difficulties—and potential delays—when siting interstate facilities. Construction in populated and environmentally sensitive areas poses significant challenges. It may be difficult for project sponsors to obtain rights-of-way (ROWs), and it is unclear whether and to what extent the States will convey eminent domain to CO_2 projects. The lack of State eminent domain rights can necessitate the costly rerouting of pipelines, potentially leading to the cancellation of a project for economic reasons. A given State or locality may not recognize the value or service provided by a proposed facility to customers outside of its own State, or deny a project due to concerns about the State's customers bearing the costs which benefit multiple States. Problems such as these have impeded the development of electric transmission infrastructure.

Experience with State siting for oil pipelines and electric transmission lines may be instructive. The Interstate Commerce Act gives the Federal Energy Regulatory Commission (FERC) authority to regulate the transportation rates and practices of oil pipelines, but does not authorize FERC to site oil pipelines.[101] That authority rests with the applicable State and local governments. An extensive network of oil pipelines has been constructed under this regulatory scheme. The majority of crude trunk lines transport oil from Canadian sources or sources in the Gulf Coast to Midwest markets, particularly around Chicago. Major oil pipeline projects are currently under construction to serve the Chicago regional market from Canadian sources, and other parts of the Midwest and Rocky Mountain States.

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[101] 49 U.S.C. § 1 *et seq.* (2006).

However, the GAO issued a report finding that the U. S. petroleum product distribution system is constrained in key areas and will likely become more so without timely investments (GAO, 2007). The report cites statements by Department of Transportation officials that restrictions in the nation's petroleum pipeline infrastructure are becoming more apparent, and that the current regulatory mechanisms may not lead to appropriate reinvestment in the industry. The report noted that building interstate natural gas pipelines in the United States is easier than building oil pipelines, because FERC has been designated lead Federal agency for the construction of natural gas pipelines and Federal eminent domain is conveyed.[102] The report recommends that various agencies explore whether a lead Federal agency could be assigned to coordinate infrastructure construction permitting for oil pipelines, and provide for eminent domain authority in order to streamline the process for siting oil and petroleum product pipelines. The recent problems in siting oil pipelines are no doubt reflective of the increasing difficulties in siting energy infrastructure in this country in general, due to heightened public opposition—particularly in more densely populated or environmentally sensitive areas.

The siting of interstate electric transmission lines on a State-by-State basis has been less successful. It is well documented that the growth rate in transmission mileage is not keeping pace with the expected growth in consumer demand for electricity over the next two decades.[103] The lack of Federal siting authority has been cited as one factor contributing to this underinvestment in electric transmission lines. This prompted Congress to provide for Federal backstop siting authority in the Energy Policy Act of 2005.[104]

Model 2: Federal Backstop Siting (the Current Electric Transmission Approach). This approach, which would allow the States to retain primary siting authority over CO_2 pipelines, would be less intrusive on State rights. A Federal agency would have the authority to site an interstate CO_2 pipeline only where a State does not or cannot site the pipeline. This approach would be effective in promoting the development of interstate CO_2 infrastructure only to the extent that most projects are actually sited at the State level, and that requests for Federal siting authority are the exception. However, if this is not the case, requiring CO_2 projects to be reviewed sequentially at both the State and Federal level will significantly increase the processing time and associated costs for projects. To the extent the project is authorized under Federal authority, eminent domain rights could also be conveyed to the permit holder to facilitate the acquisition of rights-of-way.[105] FERC's backstop authority for electric transmission

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[102] While some oil pipelines are authorized by some States to acquire necessary property by the exercise of the right of eminent domain, such authority does not exist in all States.

[103] See, e.g., Promoting Transmission Investment through Pricing Reform, Order No. 679, 71. Fed. Reg. 43294 (July 31, 2006), FERC Stats. and Regs. ¶ 31,222, at 30,467 (2006).

[104] It is worth noting that while rates for transportation by oil pipelines are set at the Federal level (by FERC), most electric transmission facilities are used and funded primarily by retail native load, with the recovery of those costs within the control of the State regulator. Outside of a regional transmission organization market, only a small fraction of the cost of a transmission facility is usually recovered through Commission-approved wholesale rates. Ultimately, investment in electric transmission infrastructure is not only dependent on an effective siting approach, but on a clear and unambiguous revenue stream, sufficient to allow the investors to recover their investment.

[105] The Energy Policy Act of 2005 conveyed eminent domain rights to permit holders on property other than property owned by the United States or a State. Pub. L. No. 109-58, § 1221(e), 119 Stat. 594, 948 (2005).

lines has not yet been exercised, although there is an application to site an interstate electric transmission facility currently pending at FERC, and there is uncertainty as to its effectiveness.

Model 3: Exclusive Federal Siting with Eminent Domain (the Natural Gas Pipeline Approach) or Without Eminent Domain (the LNG Import Terminal Approach). This approach would vest exclusive authority for the siting of interstate CO_2 pipelines in a single Federal agency.[106] That Federal agency would conduct the necessary environmental review pursuant to NEPA, and coordinate the timing of issuance of other necessary Federal permits. Having one Federal agency responsible for the siting of an interstate project would be less burdensome and more efficient than the State-by-State permitting process. In addition, a Federal agency would be in a better position than individual States to take into consideration the broad national interests that might underlie a proposal to build CO_2 infrastructure.[107]

Legislation implementing Federal siting authority could include or exclude the grant of eminent domain rights to permit holders. Currently, NGA section 7(h) enables natural gas pipelines to exercise the right of eminent domain when they are unable to acquire necessary rights-of-way by agreement with the property owner. In contrast, NGA section 3 does not convey that right to those constructing LNG import terminals. Therefore, applicants proposing the construction of LNG import terminals must secure rights-of-way from landowners by private contract.

Providing a permit holder the ability to acquire rights-of-way by exercise of the right of eminent domain ensures that project sponsors can secure necessary property rights. Absent agreement between a permit holder and any landowner, the project sponsor can acquire a right-of-way through an eminent domain proceeding and the court will establish the compensation due the owner of the land affected by the project. In certain circumstances, the ability of a project sponsor to pursue this remedy potentially can reduce both delay and costs. In contrast, without the right to condemn necessary property, the pipeline may be unable to obtain rights-of-way over a preferred pipeline route; alternative routes may ultimately prove to be economically, technically, or environmentally infeasible.

M.2 Siting CO_2 Pipelines across Tribal Lands

The Energy Policy Act of 2005 Section 1813 Study on ROWs on Indian land reaffirmed the current policy that Tribal consent is needed before any right-of-way (ROW) is given on Tribal land. Any ROW across trust land would also require Secretarial approval subject to a NEPA analysis, as well as a determination that it is in "the best interests of the Tribe." A CO_2 pipeline for CCS would be subject to the same requirements as any ROW.

In the Energy Policy Act of 2005, Title V, there are provisions that address Tribal Energy Resource Agreements (TERAs). Section 2604 et. seq. transfers authority from the Secretary to a Tribe for the approval of business leases and agreements, as well as ROWs. However, TERAs are tied to energy resource development that occurs on tribal land (as defined in Section 2601).

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[106] For this purpose, interstate CO_2 pipelines could be defined as those that cross State boundaries, and interstate storage facilities could be defined as those that straddle a State boundary or receive CO_2 from out of State.

[107] A project sponsor would need to receive all other necessary Federal authorizations including those delegated to the States.

Thus, to bypass the requirement of Secretarial approval for a ROW, a ROW for a CO_2 pipeline across Tribal lands for disposal or sale/use under a TERA would have to be directly tied to an energy development project or energy production facility on that Tribal land.

M.3 Siting CO_2 Pipelines across Federal Lands

Federal agencies have the authority to grant ROWs over Federal land. Currently, ROWs for the purpose of CO_2 pipelines are most commonly authorized by the Bureau of Land Management (BLM) pursuant to the Mineral Leasing Act (MLA) of 1920, although some have been authorized pursuant to Title V of the Federal Land Policy and Management Act (FLPMA). Pipeline ROWs granted pursuant to MLA are required to be constructed, operated and maintained as common carriers, with certain limited exceptions. Federal departments or agencies cannot obtain a ROW grant for CO_2 pipelines under the MLA, 30 U.S.C. 181.

Section 501 of FLPMA authorizes the Secretary of the Interior with respect to public lands and the Secretary of Agriculture with respect to National Forest System lands to grant ROWs for pipelines and other systems for the transportation or distribution of liquids and gases (excluding the purposes in MLA). It also provides authority to issue ROWs for other necessary transportation or other systems/facilities that are in the public interest and which require ROWs. FLPMA does not require ROWs to be constructed, operated, and maintained as common carriers. Additionally, FLPMA would be appropriate for authorizing Federally owned/operated CO_2 pipelines.[108]

Energy Corridors/Federal Lands: In an effort to expedite the permitting of energy infrastructure crossing Federal land, section 368(a) of the Energy Policy Act of 2005 (EPAct) requires agencies to designate energy corridors across Federal lands in eleven Western States for "oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities." In November 2008, a final programmatic environmental impact statement was issued that evaluates issues associated with the designation of energy corridors on Federal lands in eleven Western States. Energy corridors on Federal lands provide pathways for future pipelines as well as long-distance electrical transmission lines that are expected to help relieve congestion, improve reliability, and enhance the national electric grid. Future use of the corridors should reduce the proliferation of ROWs across the landscape and minimize the environmental footprint from development. Section 368 corridors are sited to avoid, to the maximum extent possible, significant known resource and environmental conflicts. The Act does not specifically identify CO_2 pipelines, but it also does not specifically exclude them. It seems that a CO_2 pipeline could reasonably fit the definition of "gas pipelines" in EPAct. Section 368(b) requires agencies to designate energy corridors across Federal lands in the remaining 39 States; a programmatic environmental analysis is currently being prepared.

M.4 Siting Offshore CO_2 Pipelines

Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEM) and other agencies may become involved in addressing issues associated with offshore pipelines. For example, the

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[108] See 43 C.F.R § 2801.6.

Department of Transportation Pipeline and Hazardous Material Safety Administration regulates pipeline safety under the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act of 1979 The U.S. Army Corps of Engineers issues permits for pipeline crossings of navigable waterways, shorelines, and navigation fairways. The U.S. Coast Guard regulates marine navigation generally, and may declare exposed pipeline segments or other subsurface obstructions as hazards to navigation.

M.5 CO_2 Pipeline Common Carriage Considerations for CCS Operations

The model for CCS will likely be driven by the source of CO_2 and the need to have 100 percent off-take capacity by the pipeline operator and storage facilities. This model is very different from the supply-driven natural gas industry, where wells can be shut and brought back on line as demand fluctuates. The ability to maintain availability of the pipeline and storage system will require redundancy and spare capacity in both the transportation and storage systems to accommodate swings in the CO_2 supply. If a pipeline operator fails to satisfy CO_2 off-take agreements, the emissions source could be forced to vent CO_2 emissions, scale back operations, or shut down. It is expected that shutting down a power plants will not be feasible when demand for electricity requires the plant to be online even when venting could be very costly under carbon constraints.

Current regulations for siting in some States, such as Texas and Montana, and across Federal lands require that CO_2 pipelines be designated as common carriers. Common carriage law requires operators to offer excess capacity for a fee to any entity wishing to transport their gas through the pipeline.

Regulators may consider the impacts that common carrier laws will have on the future CCS industry. Power plants and other sources of CO_2 will likely need the flexibility to reserve capacity on the pipeline system. Power plants may need to cycle power production to meet demand, resulting in changes of emissions from the source, as well as bringing sources on and off line for maintenance. Under existing common carrier structures for natural gas transmission line, there exists the risk that another company could consume excess capacity during a period of reduced emissions from an emissions source, essentially stranding the source from access to a storage site. Regulators ought to carefully consider allowing sources to reserve capacity on dedicated pipelines once a source is in operation, or consider the entire CCS system (capture, transport, and storage) as an integrated system which would not be subject to the typical common carriage requirements.

M.6 Approaches to Rate and Tariff Regulation of CO_2 Pipelines and Storage

There appears to be a particular need for flexibility in any law providing for the regulation of services provided by CO_2 pipelines and storage, because of the current uncertainty as to who will own and operate such facilities, the extent to which an integrated interstate CO_2 pipeline grid will be necessary, and what business model the providers of these services will use. In the past, when Congress adopted laws to regulate interstate businesses, such as railroads, wholesale electric power, and oil and natural gas pipelines, those businesses already existed, and therefore the laws could be structured in light of the industry's existing business practices. In considering legislation concerning Federal regulation of CO_2 pipelines and storage facilities, the need for regulatory flexibility should be balanced with a need to provide potential industry participants with some degree of certainty concerning the applicable regulatory regime.

The approaches presented below illustrate the range of possible ways to regulate the rates, terms, and conditions of service of CO_2 pipelines and storage facilities, and would be associated with slightly different standards and goals. Different regulatory approaches could be applied to storage versus transportation.

Approach 1: A State-Based Approach

Under this approach, Congress would not establish any Federal regime for regulating the rates, terms, and conditions of service of CO_2 pipelines or storage facilities. Instead, CO_2 pipelines' and CCS storage facilities' rates and services would be left to State and local regulation, if any, and/or commercial contracts. This approach could be particularly appropriate in an environment where most CCS activity was local, so that interstate transportation of the CO_2 is relatively rare. In that event, State and local regulation would be adequate, and jurisdictional issues with interstate commerce, which might otherwise act as a barrier to effective State and local regulation, would likely be minimal. This is the regulatory approach currently used for CO_2 pipelines transporting CO_2 to be employed in EOR operations.

Approach 2: Federal Open Access and Transparency Requirements

An "open access/transparency" model of regulation would require interstate CO_2 pipelines and storage facilities to provide open and non-discriminatory access both to owners of the facilities and to non-owners.[109] This model would also emphasize public disclosure of commercial transactions and terms and conditions of service as a means of controlling discrimination, but leave the negotiation of the specific rates, terms, and conditions of service to the mutual agreement of the commercial parties to a particular transaction, without any requirement that a regulatory agency review or approve the terms of those transactions. Regulators would simply establish rules and regulations for the posting or filing of transaction-specific information and/or contracts and ensure compliance with those requirements. Most regulatory actions would be in reaction to the complaints of aggrieved parties against a CO_2 pipeline or CCS storage service provider.

This may be especially beneficial where some smaller point-source generators have a limited ability to develop their own vertically integrated projects for CO_2 storage, and therefore may be interested in a commercial agreement with someone else's project. A Federal oversight role would also act as a check that might prevent discrimination, and pre-empt State policies that acted as commercial barriers to nationwide services.

Approach 3: Traditional Public Utility Regulation

[109] Congress could choose to apply such regulations only to CO_2 pipelines, leaving regulation of storage to the individual States.

A traditional utility model of regulation would establish more detailed regulatory oversight of rates and terms and conditions of service along the lines of traditional public utility regulation (similar to that used for interstate natural gas pipelines).[110]

The traditional regulatory approach relies on transparency through a tariff filing requirement, and provides extensive regulatory oversight over the rates, terms, and conditions of service; often regulators also control abandonment of services. The rates, services, terms and conditions of service, and contracts are made publicly available, usually through a tariff filing requirement. Frequently, this approach also requires prior notice of any changes in rates or services before any new or changed rates, terms or conditions of service, or services may be made effective. Another factor to consider is whether commercial terms are made available before- or after-the-fact.

This approach would maximize Federal supervision of rates and services on a nationwide basis. It would also give the Federal regulator the maximum amount of control over the rates, terms, and conditions of service. These authorities would be especially useful if development on a State-by-State level led to balkanization, inefficiency (due to lack of economies of scale, or less efficient projects in one State relative to more economical project opportunities elsewhere), or obstructions rising within a State.

Approach 4: Integrated System

There may be other approaches to regulating CO_2 pipelines and storage facilities. One possibility would be to regulate them as offshoots of the carbon-producing entity, as a *de facto* extension of a vertically integrated generation process. As such, the CO_2 pipeline and storage facility would be considered to be part of the utility plant for the generation of electricity. Where generation facilities are regulated as part of an integrated system to provide bundled wholesale and retail sales, these costs would be included in the cost of service.[111] In cases where facilities were also made available to other entities for a fee, the revenues collected from third parties would be "credited" to jurisdictional revenues. Where such facilities are part of an unbundled merchant generating facility, presumably the costs of CO_2 pipelines and storage would be at risk the same as any other generation investment. Furthermore, in regional transmission organizations with capacity markets, these costs may be subject to inclusion, e.g., included in the calculation of the cost of new entry, used in certain price setting and price mitigation provisions. Recovery of these costs would be subject generally to FERC's existing sections 205 and 206 Federal Power Act authority.

Approach 5: Hybrid System

Finally, one possible evolutionary path for the development of CCS storage and pipeline transportation suggests a possible hybrid regulatory approach. Currently, under the Natural

[110] Congress could choose to establish such Federal regulation for CO_2 pipelines, storage, or both.

[111] Under the current regulatory structure of the electric industry, this would leave investment decisions to the local utility and subject to the authority of State regulators. State commissions would be responsible for siting and rate recovery at the retail level.

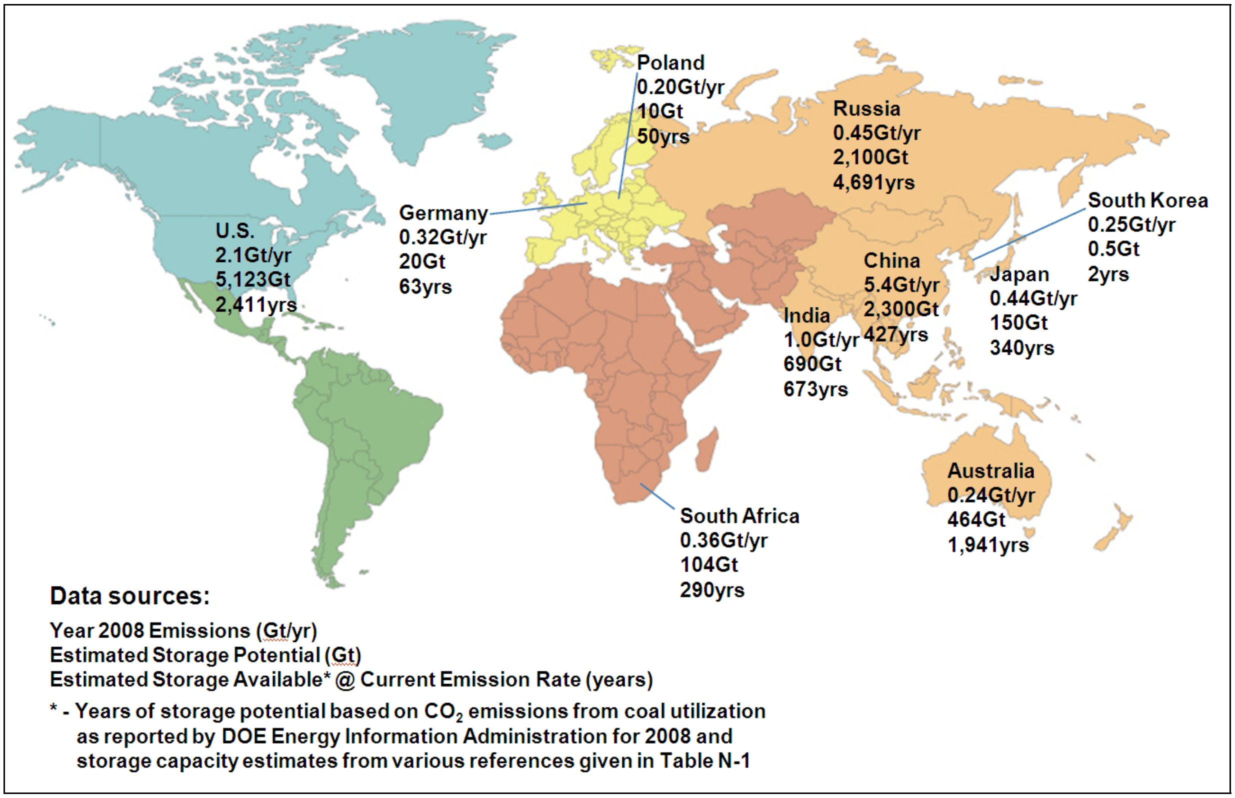
Gas Policy Act of 1978 (NGPA), FERC may set rates in one of two ways.[112] First, FERC will allow a local distribution company or an intrastate pipeline to use a State-approved rate for interstate transportation or storage services, under appropriate circumstances. Second, where a comparable State-approved rate does not exist, FERC will set a "fair and equitable" rate based on traditional cost-of-service principles. FERC's regulations establish a process for such rate approvals, which in most cases requires less time and fewer resources than the methods used to set cost-based rates for interstate pipelines and wholesale electric utilities.

If CO_2 storage is developed on an intrastate level, and is not preempted by Federal regulation, it might be possible to use NGPA-like practices to use State-approved rates to allow an intrastate storage service provider to provide interstate services.

[112] 15 U.S.C. § 3301 *et seq.* (2006).

Appendix N. International Collaboration Background

Figure N-1. Coal CO_2 Emissions, Potential Storage and Storage Resource Duration for Top 10 Emitting Countries from Coal Utilization



Source for CO_2 emissions from coal: (EIA, 2010b).

Table N-1. Storage Estimates for Top 10 Countries for CO_2 Emissions from Coal Combustion

		Storage Estimate (million tonnes)					Reference	Emissions (Gt/y)	Estimated Storage Life (years)
		Total	Saline	Oil & Gas	Coal	Other			
Australia	Total	463,500	417,000	16,500	-	-	(Carbon Storage Taskforce, 2009)	0.24	1,931
	Onshore	-	-	-	30,000	-	(Gale, 2004)		
	Offshore	-	-	15,600	-	-	(Carbon Storage Taskforce, 2009)		
China	Total	3,088,880	3,066,900	9,980	12,000	-	(Dahowski et al., 2009)	5.4	572
	Onshore	2,309,090	2,288,200	8,890	12,000	-	(Dahowski et al., 2009)		
	Offshore	779,790	778,700	1,090	-	-	(Dahowski et al., 2009)		
Germany	Total	17,080	14,900	2,180	-	-	(EU Geocapacity, 2008)	0.32	53
	Onshore	-	12,000	-	-	-	(EU Geocapacity, 2008)		
	Offshore	-	2,900	-	-	-	(EU Geocapacity, 2008)		
India	Total	572,000	360,000	7,000	5,000	200,000	(Singh et al., 2006)	1	572
	Onshore	-	-	-	-	-			
	Offshore	-	-	-	-	-			
Japan	Total	150,000	-	-	-	-	(Dooley, 2006)	0.44	341
	Onshore	-	-	-	-	-			
	Offshore	-	-	-	-	-			
Poland	Total	78,731	77,967	764	-	-	(Tarkowski et al., 2008)	0.2	394
	Onshore	-	-	-	-	-			
	Offshore	-	-	7	-	-	(Tarkowski et al., 2008)		
Republic of Korea	Total	500	-	-	-	-	(Dooley, 2006)	0.25	2
	Onshore	-	-	-	-	-			
	Offshore	-	-	-	-	-			
Russia	Total	2,100,000	-	-	-	-	(Dooley, 2006)	0.45	4,667

Table N-2. U.S. Participation in Large-Scale International CCS Projects

Project	Location	Formation Type	U.S. Role in Project / Information Gained
Weyburn-Midale	North America, Canada, Saskatchewan	Oil Field Carbonate (EOR)	U.S. scientists test multiple monitoring and simulation technologies at world's largest CO_2-EOR storage project.
Zama oil field	North America, Canada, Alberta	Oil Field Carbonate (EOR)	U.S. scientists conduct monitoring and reservoir modeling studies to support CO_2 storage with acid gas stream in carbonate oil field.
Fort Nelson	North America, Canada, British Columbia	Saline Formation	U.S. scientists support monitoring and reservoir modeling studies to verify concept of utilizing the region's carbonate saline formations for large-scale injection of anthropogenic CO_2.
Sleipner	Europe, North Sea, Norway	Marine Sandstone	U.S. scientists use time-lapse gravity survey monitoring technology to augment seismic at a subsea commercial-scale injection site.
Snøhvit CO_2 Storage	Europe, North Sea, Norway	Marine Sandstone	U.S. scientists perform reservoir modeling of geochemical, geomechanical, and seismic conditions to predict storage effectiveness in a subsea commercial operation.
CO_2SINK	Europe, Germany, Ketzin	Saline Sandstone	U.S. scientists test downhole monitoring technology based on distributed thermal perturbation sensors at pilot test site.
CarbFix	Iceland	Basalt	U.S. scientists monitor CO_2 trapping, plume tracking, and leakage by tagging CO_2 stream with carbon isotope.
Otway Basin	Australia, Victoria	Gas Field Sandstone	U.S. scientists design/fabricate/install downhole monitoring technologies based on seismic, pressure/ temperature sensors and U-tube reservoir fluid sampling and perform reservoir simulations at mid-scale injection.
In Salah gas	Africa, Algeria	Gas Field Sandstone	U.S. scientists test monitoring technologies based on seismic and satellite imagery, and model geomechanical/geochemical reservoir conditions at a commercial injection.
Ordos Basin	Asia, China, Ordos Basin	Oil and Gas Field, Saline	U.S. scientists simulate hydrogeologic and geochemical reservoir conditions and develop geomodels to assess storage effectiveness at future commercial-scale operations.

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