FINAL REPORT

For

DOE Award No. DE-FC26-03NT41994
Admendment No. A000

Report Submitted January 24, 2005

Prepared by Kevin Bliss
Phone No.: (202) 484-1026
FAX No.: (405) 525-3592

Report Submitted
By The
Interstate Oil and Gas Compact Commission
P.O. Box 53127
Oklahoma City, OK 53127-3127

DISCLAIMER

IOGCC CO2 Geological Sequestration Task Force

Table of Contents

This Page Left Blank Intentionally

IOGCC CO_2 Geological Sequestration Task Force
A Regulatory Framework for Carbon Capture and Geological Storage

Executive Summary

The prospect of global climate change fueled by the increase of carbon dioxide in the Earth's atmosphere – attributed by many climate scientists to the activities of man – has mobilized governments worldwide, including the United States, to examine ways to decrease the emission of carbon dioxide to our atmosphere from anthropogenic sources. One promising option is through carbon capture and geological storage (CCGS) – capturing carbon dioxide (CO_2) before it is released into the atmosphere and storing it in underground geologic formations.

Given the jurisdiction, experience, and expertise of states and provinces in the regulation of oil and natural gas production and natural gas storage in the United States and Canada, states and provinces will play a critical role in the regulation of CCGS. Regulations already exist in most states and provinces covering many of the same issues that need to be addressed in the regulation of CCGS. For this reason the Interstate Oil and Gas Compact Commission (IOGCC) formed its *Geological CO_2 Sequestration Task Force,* which, for the last year, has been examining the technical, policy, and regulatory issues related to safe and effective storage of CO_2 in the subsurface (depleted oil and natural gas fields, saline formations and coalbeds). Funded by the United States Department of Energy (DOE) and the National Energy Technology Laboratory, the Task Force is comprised of representatives from IOGCC member states and international affiliate provinces, state oil and natural gas agencies, DOE, DOE-sponsored Regional Carbon Sequestration Partnerships, the Association of American State Geologists (AASG), and other interested parties.

This is the Final Report of the IOGCC Geological CO_2 Sequestration Task Force (Task Force). The report that follows contains (1) an assessment of the current regulatory framework applicable to carbon capture and geologic storage and (2)

recommended regulatory guidelines and guidance documents for the states and provinces.

In this report the Task Force has chosen to use the term “carbon capture and geologic storage” over “CO_2 geological sequestration”. The former better describes the process and is less ambiguous. The Task Force has not addressed the regulatory issues involving CO_2 emissions trading and accreditation. The Task Force strongly believes that the development of future trading and accreditation regulatory frameworks should utilize the experiences of the states and provinces outlined in this report.

Guiding the work of the Task Force have been four analogues, which, in the opinion of the Task Force, provide the technological and regulatory basis for CCGS:
1) naturally occurring CO_2 contained in geologic reservoirs, including natural gas reservoirs; 2) the large number of projects where CO_2 has been injected into underground formations for enhanced oil recovery (EOR) operations; 3) storage of natural gas in geologic reservoirs; and 4) injection of acid gas (a combination of hydrogen sulfide and CO_2), into underground formations, with its long history of safe operations.

For the purposes of this report, the process of CCGS can be divided into four components labeled by the Task Force as capture, transportation, injection, and post-injection storage. Establishment of a CCGS regulatory scheme in any particular jurisdiction will require an assessment for each component of the technical issues and a review of the existing regulatory framework. Most states and provinces have existing regulatory frameworks covering all of these components with the exception of extremely long-term storage.

Principal recommendations of the Task Force in each of these four areas include:

Capture. There exists a large body of state, provincial, and federal laws and regulations dealing with emissions from industrial and energy production and power generation facilities. The Task Force notes that these regulations do not, for valid reasons, classify CO_2 as a pollutant, waste, or hazardous substance, and with few minor exceptions at the state level, do not regulate CO_2 emissions into the atmosphere. States that already might have defined CO_2 as a waste, air contaminant, or pollutant might be advised to reassess that definition so as to not negatively impact CCGS development. While some nations, in response to concern over global climate change, have adopted regulatory imperatives that limit CO_2 emissions, the United States has taken a different approach built upon voluntary efforts to reduce greenhouse gas intensity. Under the voluntary system present in the United States, the development of CCGS projects likely will be limited in the near future to relatively pure streams of CO_2 that prove to be economic for use in CO_2 EOR projects. The Task Force recognizes, however, that this scenario could change with the introduction of emission caps, economic incentives (tax and otherwise), and/or advances in technology that reduce capture costs.

Transportation. More than 3,500 miles of high-pressure CO_2 pipelines have been constructed in the United States. In addition, numerous parallels exist between CO_2 transport and natural gas transport. Most rules and regulations written for natural gas transport by pipeline include CO_2 and are administered and enforced by the U.S. Department of Transportation's Office of Pipeline Safety (OPS). States also may regulate under partnership agreements with OPS. These rules are designed to protect the public and the environment by assuring safety in pipeline design, construction, testing, operation, and maintenance. Given the large body of experience in pipeline operation, including CO_2, well established regulatory frameworks, and well established materials and construction standards, there is little necessity for additional state and provincial regulations in this area. The Task Force recognized in its deliberations that state eminent domain powers necessary for pipeline construction and "open access" and the potential need for Federal Energy Regulatory Commission (FERC) jurisdiction might be future issues that need to be addressed at the state and federal level.

Injection. Although distinct, injection and storage are part of the same operation and should be considered together. Given the regulatory experience of the states and provinces in the area of CO_2 EOR, natural gas storage and acid gas injection, future CO_2 regulations for injection and storage should be built upon the regulatory frameworks already tested and in place. However, the Task Force has concluded that for purposes of regulation, a distinction needs to be made between injection for purposes of EOR, which has a project time frame, and injection for non-EOR purposes, which spans a much longer time frame.

The Task Force recommends that CO_2 injection for EOR purposes continue under current state and provincial regulations. Many states regulate EOR under the Underground Injection Control Program (UIC) of the Safe Drinking Water Act as Class II wells.

Concerning CO_2 injection for non-EOR purposes, the Task Force has concluded that, given the commodity status of CO_2 in the market and given the natural gas storage and acid gas injection regulatory analogues, future CCGS projects can and should incorporate existing state and provincial natural gas storage statutes and existing regulatory frameworks. The Task Force recognizes, however, that the U.S. Environmental Protection Agency (EPA) may recommend that the UIC program should also cover non-EOR CO_2 injection wells. The Task Force suggests that EPA, before it makes any recommendation concerning UIC applicability to non-EOR CO_2 injection, work closely with states. Further, should EPA make such a recommendation, the Task Force strongly suggests a new classification for such wells that allows for regulation dealing with economic considerations not contemplated by the UIC program. The Task Force strongly believes that inclusion of non-EOR CCGS wells under Class I or Class V of the UIC program would not be appropriate or conducive to the growth of CCGS as a viable option in mitigating the potential impact of CO_2 emissions on the global climate.

Post-Injection Storage. There exist a significant number of CO_2 EOR injection projects in the U.S., and, therefore, "storage" of CO_2 is already taking place. Most of this CO_2 is from natural sources, as opposed to anthropogenic or industrial sources (as would be the case with CCGS). CO_2 EOR injection and storage has the economic benefit of increasing the production of oil. It also increases the likelihood that CO_2 EOR projects will be the vehicle that will drive CCGS, at least in its early years. It can be the means to build both injection/storage experience, regulatory and otherwise, and physical infrastructure (pipelines/facilities). Together the EOR, natural gas storage, and acid gas injection models provide a technical, economic, and regulatory pathway for long-term CO_2 storage. However, the sparsity of post-injection CO_2 EOR projects and abandoned natural gas storage fields have not provided adequate guidance for a long-term CO_2 storage regulatory framework. Consequently, a regulatory framework needs to be established to determine long-term liability and to address monitoring and verification of the reservoir and mechanical integrity of wellbores penetrating formations in which CO_2 has been emplaced over storage time frames.

Two final issues considered by the Task Force in the area of post-injection storage are worthy of note. The first concern arises in the ownership of storage rights (reservoir pore space) and payment for use of those storage rights. Jurisdictions must consider the potential need for legislation to address this complex issue. The second concerns liability. During the operational phase of the CO_2 storage project, the responsibility and liability for operational standards, release, and leakage mitigation lies with either the owner of the CO_2 – established through contractual or credit arrangements – and/or the operator of the storage facility. Long-term ownership (post-operational phase) will remain with the same entities. However, given the nonpermanence of responsible parties over long time frames, oversight of CCGS projects will require creation of specific provisions regarding financial responsibility in the case of insolvency or failure of the licensee. The Task Force believes that this assurance ultimately will reside with federal and state or provincial governments cooperatively through the establishment of specialized surety bonds, innovative government and privately backed insurance funds, government trust funds, and public, private, or semi-private partnerships.

The Task Force offers two important recommendations for states and provinces as they begin their process of amending existing statutes and regulations and promulgating new rules to effectuate CCGS. The first is that the states and provinces actively solicit public involvement in the process as early as possible. The second is that the process from the outset be clear and transparent. As stated previously, although CO_2 is not considered a pollutant and not considered hazardous and has a long and safe history of being transported, handled, and used in a variety of applications, the public must be educated on the facts and included in an open regulatory development process.

The Task Force gratefully acknowledges the support of the U.S. Department of Energy, the National Energy Technology Laboratory, and the Illinois State Geological Survey, as well as the support of the states/provinces and other entities that generously contributed their employees’ time to the production of this report.

1. Chapter 1 – Introduction

While the major components of Earth's atmosphere are nitrogen (78%) and oxygen (21%), there are also small concentrations of other gases such as carbon dioxide (CO_2), methane (CH_4), nitrogen dioxide (NO_2), chlorofluorocarbons (CFCs), ozone (O_3), aerosols, and water vapor. In total these other gases comprise only 1% of our atmosphere and are commonly referred to as "greenhouse gases" because of their effect on warming our planet. The "greenhouse" effect results in the capture of radiation from sunlight by preventing radiative heat from reflecting back into space. While this greenhouse effect is critical in making our planet warm and habitable, the fact that concentrations of CO_2 are increasing yearly raises concern that it may be a primary factor in climate change or global warming. Although the science of climate change is evolving and far from certain, there is growing interest both within industry and government in the possible opportunities for mitigating the release of carbon into our atmosphere, particularly through carbon capture and geologic storage (CCGS). The interest in the storage of carbon stems from the fact that every year we, the inhabitants of Earth, release ever-greater amounts of carbon dioxide into our atmosphere – largely the consequence of our burning carbon fuels (oil, natural gas, and coal) for energy.

The conclusion of a key United Nations working group of the Intergovernmental Panel on Climate Change (IPCC) is that emissions of greenhouse gases and aerosols due to human activities are likely to alter the atmosphere in ways that are expected to affect the climate.[1] A major concern relates to increasing concentrations of greenhouse gases, such as CO_2 and methane, that may have a positive radiative forcing, thus tending to warm the Earth's surface. The IPCC notes that the global average surface temperature has increased over the 20th century by 0.6 degrees C[2] and that the 1990s was the warmest decade on record since 1880, with 1998 and 1997 the warmest and second warmest years. All told, six of the warmest years since

[1] Intergovernmental Panel on Climate Change, Third Assessment Report: Climate Change, 2001.
[2] Intergovernmental Panel on Climate Change, Third Assessment Report: Climate Change, Summary for Policy Makers, p. 20, 2001.

1880 were in the 1990s, and each year of the decade of the 1990s was one of the top 15 warmest of the last century.[3] Since 1750, atmospheric concentrations of CO_2 have increased 32 percent, from 280 parts per million (ppm) to 375 ppm concentration in 2003.[4] For purposes of this report, it is assumed that this increase is the result of the activity of mankind.

This increase in CO_2 requires the development and implementation of mitigation strategies aimed at reduction of CO_2 concentrations. It can be argued as to when or to what extent such strategies may need to be implemented. However, there is consensus that these mitigation strategies may need to be deployed and we must have developed a knowledge base to implement these strategies. Consequently, the methodologies of capturing and storing CO_2 emissions prior to release to the atmosphere must be investigated and perfected.

Reducing concentrations of anthropogenic[5] greenhouse gases can be accomplished in four basic ways: 1) through energy conservation and energy efficiency; 2) by using technologies involving renewable energy, nuclear power, hydrogen, or fossil fuels containing lower percentages of carbon, i.e., natural gas; 3) by indirect capture of CO_2 after its release into the atmosphere utilizing the oceans or terrestrial sequestration, i.e., reforestation, agricultural practices, etc.; or 4) by carbon capture and geological storage, whereby CO_2 is captured and stored in geologic formations through underground injection (instead of being released into the atmosphere).[6]

---

[3] National Oceanic and Atmospheric Administration, 2000, Climate of 1999-Annual Review, National Climatic Data Center, http://www.ncdc.noaa.gov

[4] Keeling, C.D. and T.P. Whorf. Atmospheric CO_2 records from sites in the SIO air sampling network. In Trends: A Compendium of Data on Global Change. Carbon Dioxide Information Analysis Center, 2004, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tenn., U.S.A.

[5] Anthropogenic is defined in this context as "involving the impact of man on nature: induced or altered by the presence and activities of man". Webster's Third New International Dictionary, G. & C. Merriam Company, 1981.

[6] The Department of Energy's Office of Fossil Energy, on behalf of the U.S. government, has begun an aggressive research program in this regard through its National Energy Technology Laboratory (NETL).

Four existing analogues provide guidance concerning CCGS. These are: 1) naturally occurring CO_2 contained in geologic reservoirs[7], including natural gas reservoirs;[8] 2) the vast number of projects where CO_2 has been injected into underground formations for enhanced oil recovery (EOR) operations;[9] 3) storage of natural gas in geologic reservoirs; and 4) injection of acid gas[10] into underground formations, which has a long history of safe operations. These well-documented analogues provide the technological and regulatory basis for CCGS.

The interest of the Interstate Oil and Gas Compact Commission (IOGCC)[11] in CCGS stems from the fact that for half a century the states and provinces have been the principal regulators of EOR in the United States and Canada[12], as well as for natural gas and hydrogen sulfide (H_2S) storage. Regulations already exist in petroleum producing states and provinces covering many of the same issues that need to be addressed in the regulation of CCGS.[13] As part of their responsibilities, state and provincial oil and natural gas regulators have focused on environmental issues since

---

[7] The best-known examples are the three underground CO_2 source fields for enhanced oil recovery projects that are located in New Mexico and Colorado. Here naturally sourced CO_2 is trapped under pressure within geological structures that have been utilized via drilling as sources of CO_2 for injection into oil reservoirs in West Texas for more than thirty years. Natural storage sites occur in many other locales as well, some effectively permanent and some with evidence of spill or seal leakage.

[8] CO_2 can be found in natural gas reservoirs in concentrations that can reach as high as 70%.

[9] See section 2.5 for a history of CO_2 use in EOR.

[10] Acid gas is a combination of hydrogen sulfide (H_2S) and CO_2.

[11] The IOGCC represents 30 member and 7 affiliate oil and natural gas producing states. There is a map and listing of the IOGCC member states on the inside front cover of this publication. Organized as an interstate compact in 1935 – in essence a treaty among states ratified by Congress – the mission of the IOGCC is to promote the conservation and efficient recovery of domestic natural gas and oil resources, while protecting health, safety, and the environment. It conducts studies for the states, writes model statutes and regulations, fosters dialogue among producing states, and works with the federal government to promote sound energy policy.

[12] According to the Canadian Constitution, natural resources and the environment are under provincial jurisdiction. The federal government exerts jurisdiction over transborder issues (international and interprovincial), the Territories, and territorial waters. In 2002, the Province of Alberta passed legislation that, in effect, stipulates that "...carbon dioxide and methane are not toxic and are inextricably linked with the management of renewable and non-renewable natural resources, including sinks", reaffirming the provincial jurisdiction over reduction of CO_2 emissions. Thus, as long as CO_2 is not stored in geological media under Canadian territorial waters or in the Territories, provinces have full jurisdiction over CO_2 capture and geological storage.

[13] Some states that do not have petroleum production store natural gas and, therefore, have in place natural gas storage regulations. Thus these states, too, have regulations that at least in part cover many of the same issues that need to be addressed in the regulation of CCGS.

the 1800s. As science developed methods for recovering more petroleum through enhanced recovery techniques, like use of CO_2, states and provinces modified their regulations to accommodate these advances in technology. The member states of IOGCC and its international affiliate provinces have considerable experience in regulating the affairs of CO_2 handling. In Texas alone, the Railroad Commission has regulatory oversight of an enhanced oil recovery industry handling more than 50 million metric tons (Mt)[14] per year of CO_2. Handling involves the aspects of transportation, injection, processing, and production of CO_2, much of which is at considerable pressure. Many states and provinces also have experience in regulating CO_2 in combination with toxic gases such as H_2S. As noted above, much of the regulatory experience in natural gas storage has direct application to CCGS.

The IOGCC began exploring a potential role for the states in CCGS in July 2002. With the sponsorship of the United States Department of Energy (DOE), the lead federal department on this issue, the IOGCC convened a meeting of state regulators and state geologists. The purpose of the meeting was to explore the issue of CCGS and assess the interest of the states, through the IOGCC, in undertaking the development of regulatory guidelines and guidance documents for CCGS. As a result of that meeting, the IOGCC in December 2002 unanimously passed Resolution 02.124 calling for establishment of a "Geological CO_2 Sequestration Task Force". The IOGCC Geological CO_2 Sequestration Task Force (Task Force) has been tasked by DOE with two primary objectives:

1. Examination of the technical, policy and regulatory issues related to safe and effective storage of CO_2 in the subsurface (oil and natural gas fields, coalbeds and saline formations[15]), whether for enhanced hydrocarbon recovery or long-term storage; and

[14] 1 million metric tons = Megaton (Mt). 1 metric ton = 1.1023 short tons = 2,204.62 pounds.
1 metric ton of CO_2 is equal to 18.85 Mcf and 17,200 standard cubic feet (scf) at standard conditions.

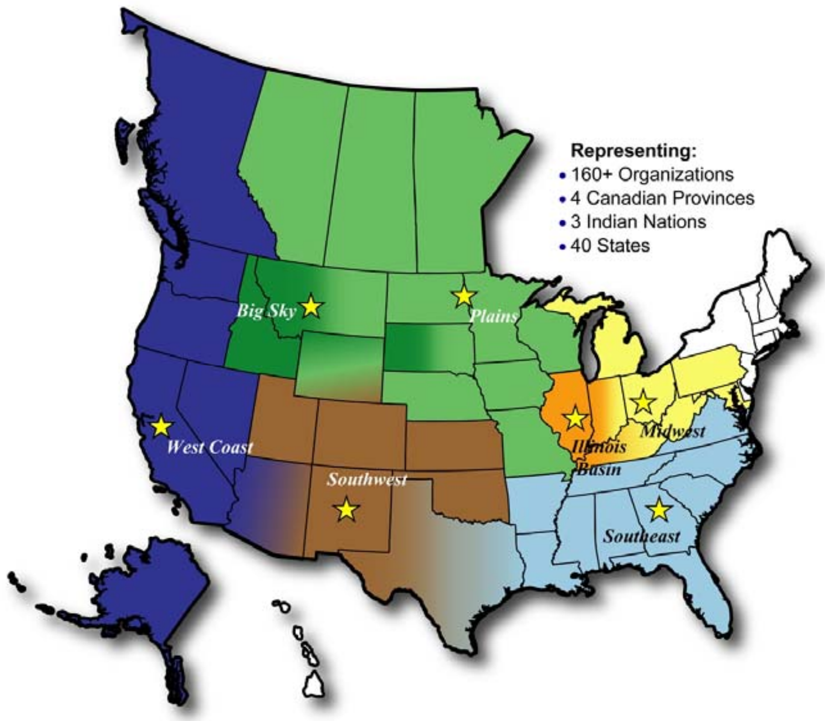
[15] Although not part of the tasking from DOE, the Task Force Final Report also addresses the potential use of salt caverns and organic shales for storage of CO_2.

2. Production of a Final Report containing (1) an assessment of the current regulatory framework likely applicable to geologic CO_2 sequestration, and (2) recommended regulatory guidelines and guidance documents. The Final Report and the documents contained therein will lay the essential groundwork for a state-regulated, but nationally consistent, system for the geologic sequestration of CO_2 in conformance with national and international law and protocol.

This is the Final Report of the CO_2 Task Force. The members of the Task Force are listed in Appendix 1. The Task Force is comprised of representatives from IOGCC member states and international affiliates, state oil and natural gas agencies, DOE, DOE-sponsored Regional Carbon Sequestration Partnerships, the Association of American State Geologists (AASG), and other interested parties.

In developing the Final Report, the Task Force has worked closely with DOE and the seven Regional Carbon Sequestration Partnerships established by DOE. The regional partnerships represent a government/industry effort to determine the most suitable technologies, site-specific sinks, regulations, and infrastructure for carbon capture, storage, and sequestration in different areas of the United States. These partnerships are comprised of state agencies, universities, and public companies and include more than 150 organizations spanning 40 states, three Indian nations and four Canadian provinces. The seven regions are listed in Figure 1.0-1.[16]

[16] The partnerships are a key ingredient of the *United States Global Climate Change Initiative*.



Partnership	Partnership Lead	States Represented
Midwest Regional Carbon Sequestration Partnership	Battelle Memorial Institute	IA, KY, MI, MD, OH, PA, WV
An Assessment of Geological Carbon Sequestration Options in the **Illinois Basin**	The Board of Trustees of the University of Illinois, Illinois State Geological Survey	IL, IN, KY
Southeast Regional Carbon Sequestration Partnership	Southern States Energy Board	AL, AR, FL, GA, LA, MS, NC, SC, TN, TX, VA
Southwest Regional Partnership for Carbon Sequestration	New Mexico Institute of Mining and Technology	AZ, CO, KS, NE, NM, OK, TX, UT, WY
West Coast Regional Carbon Sequestration Partnership	State of California, California Energy Commission	AK, AZ, CA, NV, OR, WA
Big Sky Regional Carbon Sequestration Partnership	Montana State University	ID, MT, SD, WY
Plains CO2 Reduction Partnership	University North Dakota - Energy & Environmental Research Center	IA, MO, MN, ND, NE, MT, SD, WI, WY

Figure 1.0-1 Regional Carbon Sequestration Partnerships.[17]

[17] U.S. DOE – NETL Carbon Sequestration Partnership web site: http://www.netl.doe.gov/coal/Carbon%20Sequestration/partnerships/index.html, specifically, http://www.netl.doe.gov/coal/Carbon%20Sequestration/partnerships/index.html.

Worldwide, in response to concern over global climate change, some nations have put into place regulatory imperatives that limit CO_2 emissions. Further, there is an international consensus that CO_2 storage is considered a viable alternative in assisting those nations in achieving their emission goals. While the United States has not yet promulgated any regulations covering CO_2 emissions, under its *Global Climate Change Initiative* the U.S. has set a goal to reduce greenhouse gas intensity by 18% by 2012 through encouraging voluntary efforts by industry.

As was stated above, the purpose of this Task Force Report is to: 1) examine the technical, policy and regulatory issues related to CCGS; 2) assess the current regulatory framework likely applicable to CCGS; and 3) provide regulatory guidelines and guidance documents to the states for adaptation of their current regulatory regimes to accommodate CCGS. Among the specific recommendations of the Task Force contained in Chapter 4 are two general, but very important, recommendations for states as they begin their process of amending existing regulations and promulgating new regulations to effect CCGS. The first is that the states actively solicit public involvement in the process as early as possible. The second is that the process from the outset be clear and transparent. Although CO_2 is neither a waste nor hazardous and has a very long and safe history of being transported, handled and used in a variety of applications, the public must be educated on the facts and included in a clear and open regulatory development process.

It is also useful to note that in this report the Task Force has chosen to use the term “carbon capture and geologic storage” over “CO_2 geological sequestration”. The former better describes the process and is less ambiguous in interpretation.

Of relevance also in this Task Force Report is a discussion of the issue of sustainability. The purpose of CCGS is to provide one methodology to help assure a sustainable future. The concept of promoting practices today that assure a sustainable future has been gaining traction nationally and internationally in recent years, at the same time that the need to develop strategies to address global climate change has become more and more evident. CCGS provides an opportunity for the fossil fuel sector to play a key supportive role on both fronts. Current energy scenarios assume that fossil fuels will continue to be the primary source of energy for the world and the United States well into the 21st century.[18] While there may be some who feel that coal and oil and natural gas interests have no place in sustainability discussions, the very foundation of sustainability theory is the concept that environmental, economic, and social interests are mutually dependent and mutually supportive, and energy derived from fossil fuels is a major factor in the national and global economy. While the day will come when we shift to other energy sources, we have an opportunity now to utilize those same sectors to make a significant contribution to produce cleaner energy and reduce the amount of CO_2 released to the atmosphere.

The Task Force Final Report is comprised of 3 chapters. The next chapter, Chapter 2, entitled “CO_2 Overview” contains general information about CO_2 and its past and potential uses, including more information on its potential role in climate change. The remaining chapter entitled “Regulatory Overview” covers the technical and regulatory aspects (including a discussion of regulatory gaps and recommendations) of the capture, transportation, injection and post-injection storage of CO_2.

---

[18] EIA, 2004, Energy Information Administration, Annual Energy Outlook 2004 with Projections to 2025, Report #: DOE/EIA-0383 (2004), January, 2004, 278, http://www.eia.doe.gov/oiaf/aeo/.

IEA, 2002, International Energy Agency, World Energy Outlook 2002, ISBN 92-64-19835-0 (2002), 530p, summary at: http://library.iea.org/textbase/weo/pubs/weo2002/WEO2002_1sum.pdf.

2. Chapter 2 – CO_2 Overview

The natural carbon cycle is an exchange of carbon between the atmosphere, oceans, and terrestrial biosphere. As part of the carbon cycle, CO_2 is removed from the atmosphere by plants in a process called photosynthesis. In this process the carbon and oxygen atoms are separated, with oxygen being returned to the atmosphere and carbon being synthesized into the plant structure using light as the energy source. In certain oceanic settings carbon is often deposited as carbonate sediment, mainly limestone and dolomite, over geologic time. The weight of scientific evidence suggests that human activity has altered the operation of the natural carbon cycle to the extent that CO_2 formed by the combustion of hydrocarbons is not completely absorbed in the exchange process and remains in the atmosphere for a period of 50 to 200 years.[19] Figure 2.0-1 is a graphic of the global carbon cycle.

[19] Greenhouse Gasses and Climate Change, April 2, 2004, IEA Greenhouse Gas R&D Programme.

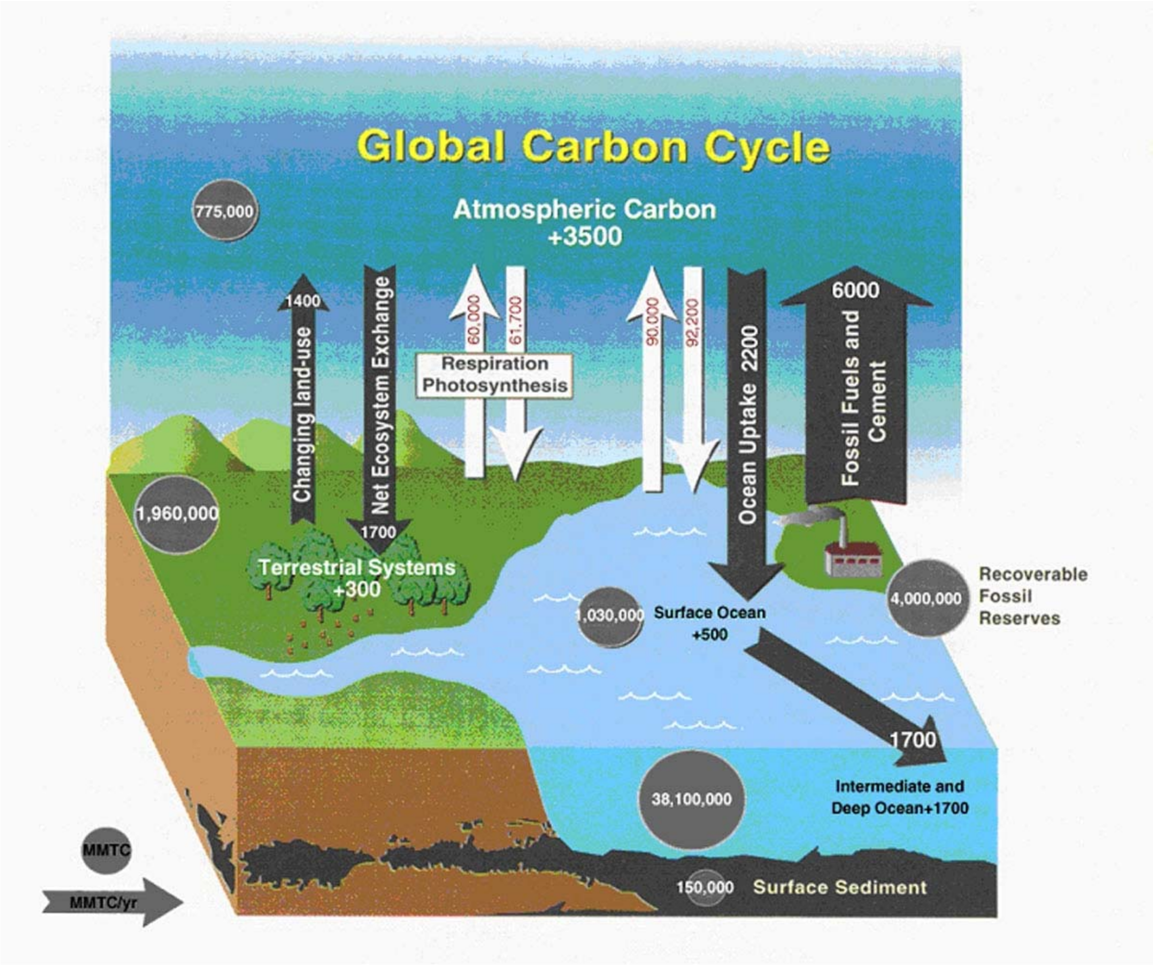


Figure 2.0-1 Global Biogeochemical Carbon Cycle. Includes human influence from fossil fuel combustion and changing land-use patterns. Black arrows indicate net fluxes and white arrows indicate gross fluxes. Annual net additions are shown as + numbers, and pool sizes (circles) are shown in gray. All quantities are in million metric tons (Mt) Carbon, and all fluxes are in million metric tons (Mt) Carbon/yr. [20]

The purpose of CCGS is to provide a means of capturing and storing CO_2 that otherwise would be released to the atmosphere through the combustion of hydrocarbons. As was noted in the Introduction, the concept of the geologic storage of CO_2 has several important analogues. The natural occurrence of CO_2 in geologic reservoirs demonstrates the ability of geologic formations to contain CO_2 over extremely long periods of time, exactly our goal in implementing CCGS.

---

[20] S.M. Benson, R. Hepple, J. Apps, C.F. Tsang, and M. Lippman 2002 Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations, Report No. LBNL-51170, Lawrence Berkeley National Laboratory, Berkeley, California, p.14, modified from U.S. DOE, 1999.

Additionally, EOR operations have demonstrated that CO_2 can be safely transported and injected into geologic formations. Yet another is storage of natural gas in geologic reservoirs, providing an additional useful precedent for underground storage of CO_2. The final analogue is the safe handling and injection of acid gas, which includes H_2S, a byproduct of some natural gas production, that is, unlike CO_2, a substance that poses significant health and safety concerns. The long history of the safe handling of this hazardous gas is well documented. Additionally, thermodynamically, H_2S is very similar to CO_2 and thus physical handling and processes are similar. These well-documented analogues provide the technological and regulatory basis for CCGS.

2.1 Carbon Dioxide (CO_2) Characteristics

At normal atmospheric conditions, CO_2 is a non-hazardous, odorless gas that makes up a small fraction of Earth's atmosphere (0.03%).[21] CO_2 occurs in four forms: 1) as a gas which is 1.5 times denser than air; 2) as a liquid, occurring in the subsurface in regions with low geothermal gradients where the pressure is sufficiently high but the temperature is still below the critical point; 3) as a supercritical fluid that behaves like a gas but has density characteristics of liquids at pressures greater than 1,073 pounds per square inch (psi) and temperatures greater than 87.7 degrees F; and 4) as a solid form most commonly referred to as dry ice (remains solid below temperatures of minus 109 degrees F). Assuming normal geologic pressure and temperature gradients (0.433 psi/ft, 15 degrees F/1000 ft) those reservoirs deeper than approximately 2,500 feet will dictate that CO_2 will exist as a supercritical fluid.

[21] For comparison, exhaled air from humans is approximately 3.5% CO_2.

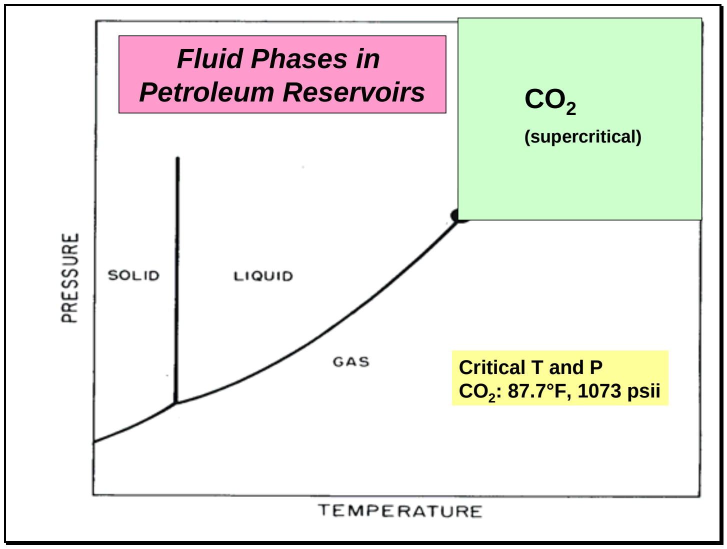


Figure 2.1-1 Fluid Phases in Petroleum Reservoirs.[22]

Consequently, the capture, transportation, injection, and storage of CO_2 will involve only the gaseous, liquid, and supercritical phases of CO_2. Humans cannot detect CO_2 in its gaseous form without detection equipment and, as Figure 2.1-2 shows, increased concentrations of CO_2 do have potential human health and safety consequences. However, the risk associated with CCGS depends much more on effective dispersion than total quantity of CO_2.

[22] Illustration courtesy of the Midwest Geological Sequestration Partnership (Illinois Basin), 2004.

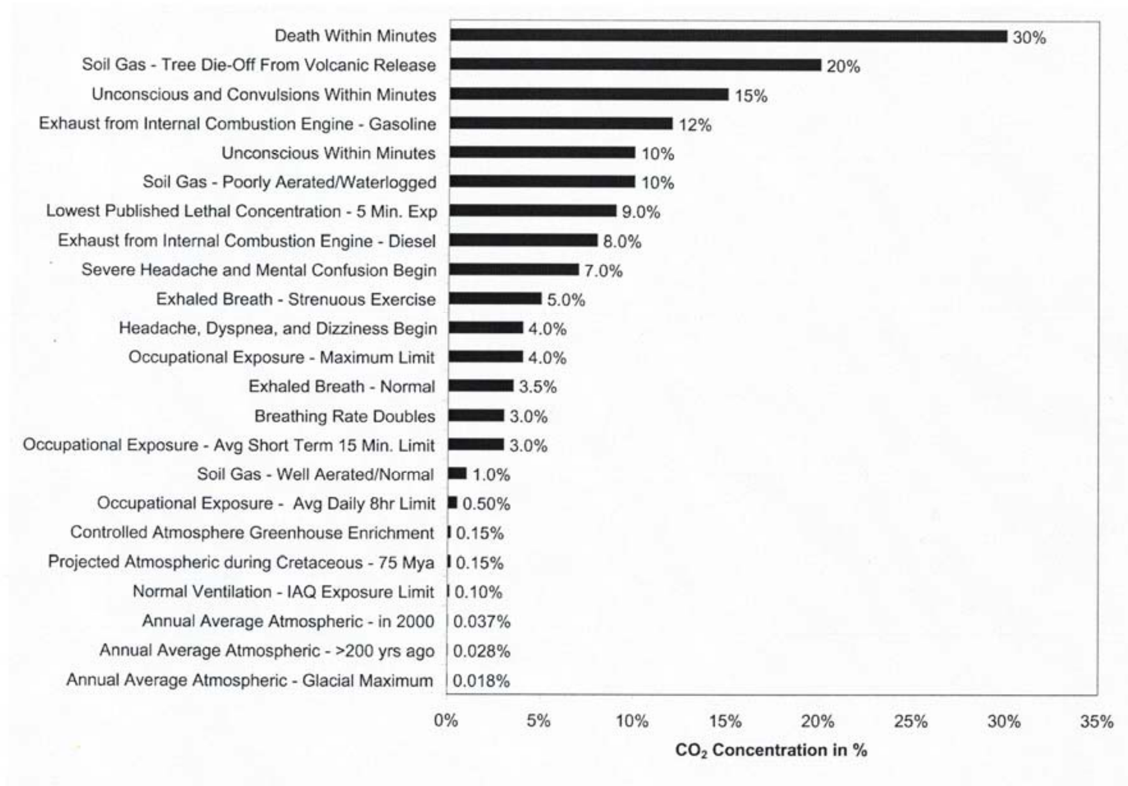


Figure 2.1-2 Comparison of Ambient Concentrations of CO_2 and Risks of Exposure.[23]

2.2 Uses of CO2

As noted above, CO_2 is a naturally occurring gas and is essential to the natural plant life process on Earth. Carbon dioxide is also a valuable commodity with many beneficial uses as shown in Figure 2.2-1. However, all of these uses of CO_2 only utilize a small fraction of the total 2,564 Mt of CO_2 available from anthropogenic sources excluding transportation sources. See Figure 2.2-2. This emphasizes the important role that CCGS must play.

---

[23] Benson, S.M., Hepple, R., Apps, J., Tsang, C.F. and Lippman M., Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations, Report No. LBNL-51170, Lawrence Berkeley National Laboratory, Berkeley, California, p.14, 2002, modified from U.S. DOE, 1999, p.23 and Appendix 4 - Data tables with references.

Beneficial Uses of CO_2

1	Refrigeration	Used for cooling
2	Fire Extinguishers	Extinguishes some fires by depriving the fire of oxygen
3	Carbonated beverages	Produces carbonation
4	Decaffeinated coffee	Used in super cooled fluid extraction process
5	Dry ice	Used to make stage fog and other visual effects
6	Feedstock	Can be used as feedstock for chemical manufacturing
7	Biofuels	Aids in the process of algae growth to make biofuels

Figure 2.2-1 Beneficial Uses of CO_2.

CO_2 Emissions in the United States

(2000 & 2002 Data)

Sources	**US Total Metric ton**
Power Generation	2,239,700,000
Coal	1,868,400,000
Natural Gas	299,100,000
Oil	72,200,000
Industries	324.789.000
Refinery	184,918,000
Iron and Steel	54,411,000
Cement	42,898,000
Ammonia	17,652,000
Aluminum	4,223,000
Lime	12,304,000
Ethanol	8,383,000
Total	**2,564,489,000**

Figure 2.2-2 CO_2 Emissions in the United States.[24]

[24] Illustration courtesy of the Midwest Geological Sequestration Partnership (Illinois Basin), 2004.

2.3 Geologic Options for Carbon Dioxide Storage

There are four primary options for the geologic storage of CO_2, discussed in more detail below: 1) storage in depleted oil and natural gas reservoirs; 2) storage in deep saline formations; 3) storage in salt caverns; and 4) adsorption within coalbeds that are unminable because of depth, thickness or other economic factors. In addition, there is the possibility of other storage options such as organic shales, fractured basalts, and hydrates. The four primary geological options involve injection of CO_2 through wells into the receiving formations or coal layers. Figures 2.3-1 and 2.3.3-1 illustrate the geologic options for underground injection of CO_2. There are advantages to injecting into deeper formations, deeper than 2,500 feet, because the CO_2 can be emplaced in a supercritical state under pressures exceeding 1,200 psi. Supercritical CO_2 occupies less pore space for a given quantity of CO_2, thereby maximizing the reservoir capacity for geologic storage.

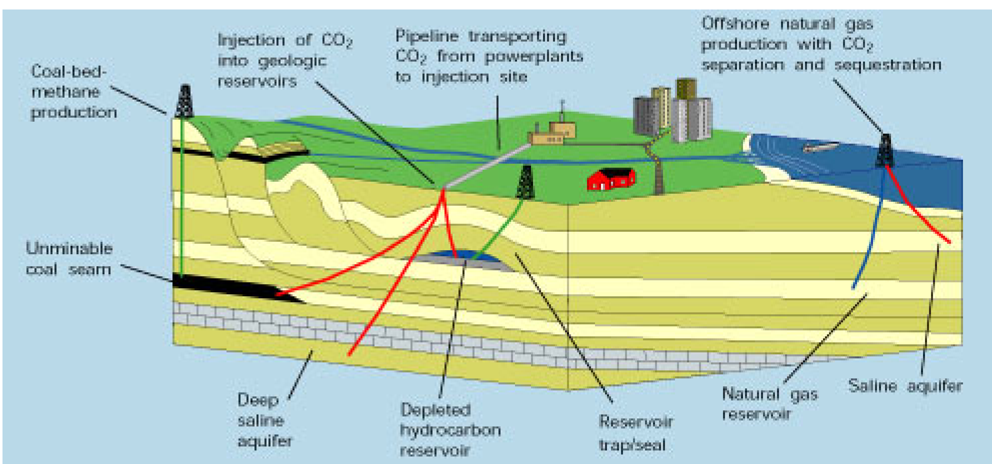


Figure 2.3-1. Potential CO_2 Sequestration Reservoirs and Products. Red lines indicate CO_2 being pumped into the reservoirs for sequestration, green lines indicate enhanced recovery of fossil fuels caused by CO_2 sequestration, and the blue line indicates conventional recovery of fossil fuels. The offshore natural gas production (blue line) and CO_2 sequestration scenario is currently occurring off the coast of Norway at the Sleipner complex operated by Statoil. There, the gas produced is a mixture of CO_2 and methane. The CO_2 is removed and injected into a nearby saline aquifer.[25]

[25] Diagram and explanation from U.S. Geological Survey Fact Sheet 26-03, March 2003 - Online Version 1.0. See: http://pubs.usgs.gov/fs/fs026-03/fs026-03.html

Many regions of the United States offer one or more of these geologic options, the most common of which are discussed below.

2.3.1 Depleted Oil and Gas Fields

Many regions of the U.S. and the world have produced oil and natural gas from geologic traps that represent a substantial reservoir capacity available for storage of CO_2. Where these reservoirs are below 4,000 feet, they offer tremendous pore volume space for supercritical CO_2 injection and storage. These geologic traps by their very nature, having confined accumulations of oil and natural gas over millions of years, have proven their ability to contain fluids and gas. Additionally, if storage pressures of CO_2 stay below original reservoir pressures, fluid containment is assured if leakage from wellbore penetrations can be avoided.

2.3.2 Deep Saline Formations

The CO_2 storage option with the greatest potential among the geologic possibilities nationwide is the injection of CO_2 into saline formations significantly below underground sources of drinking water. Storage of CO_2 in deep saline formations currently may not have demonstrated confining mechanisms, unlike depleted oil and natural gas reservoirs, but has the advantage of providing volumetrically the largest CO_2 storage potential of the three primary geologic options. In addition, access to saline aquifers often occurs close to existing CO_2 emission sources, such as coal-fired power plants. The water in some of these formations, for example in the depth range of 4,000 to 5,000 feet in the Illinois Basin, has many times the salinity of sea water and hence is not usable as a potable resource. Injection of CO_2 into these deeper saline formations could be contained through solubility trapping (CO_2 dissolution in formation waters), structural trapping (formation of a secondary gas cap within formation boundaries), or through mineral trapping (carbonate precipitation).

An example of a full-scale utilization of a saline reservoir for CO_2 storage is occurring off the coast of Norway. In this project, 1 Mt of CO_2 per year is separated from a natural gas production stream and injected into the Utsira saline formation well below the seabed of the North Sea.[26] In the U.S., our knowledge of deep saline reservoirs comes from oil and natural gas exploration, from deep-well waste injection, and from natural gas storage into saline formations. A small pilot project recently injected a total of 1,600 Mt of CO_2 into the Frio formation of east Texas, initiated through funding by DOE. The purpose of the pilot program is to test the containment parameters of injecting CO_2 into a saline aquifer. If saline storage proves successful for CCGS, the storage capacities are potentially significant. An example is the Mt. Simon Sandstone, which is used extensively for natural gas storage in the Midwest, where knowledge of its porosity, permeability, injectability, and water chemistry have been developed though the operation of natural gas storage facilities. The potential storage capacity of the Mt. Simon Sandstone has been estimated to be at least 160 billion metric tons (Gt) of carbon.[27] CO_2 injected into saline reservoirs would be in the form of a supercritical fluid, under pressure and temperature conditions where it would exhibit liquid-like behavior, and could be contained in a structural or stratigraphic trap much like oil and natural gas. Also important is an understanding of the sealing units above the saline reservoirs that must act as vertical permeability barriers to contain injected CO_2 and the degree to which CO_2 dissolves in the saline waters. Where such units have been used for natural gas storage, extensive studies have been undertaken to ensure natural gas containment. Deep saline reservoir storage of CO_2 will incorporate detailed studies of reservoir seals to ensure containment and will build on the experience of natural gas storage facilities.

---

[26] Saline Aquifer CO_2 Storage, IEA Greenhouse Gas Programme, http://www.ieagreen.org.uk/

[27] Gupta, N., Wang, P., Sass, P., Bergman, P., and Byrer, C., 2001, Regional and site-specific hydrologic constraints on CO_2 sequestration in the Midwestern United States saline formations: Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies, CSIRO Publishing, pp. 385-390.

2.3.3 Salt Cavern Storage

For over 40 years, salt caverns have been used successfully in the storage of oil and natural gas and provide an option for the storage of CO_2. Carbon dioxide can be stored in salt caverns as a gas, liquid, or in supercritical state. Several states currently have in place regulatory frameworks[28] for salt cavern storage of natural gas. These rules and regulations, with appropriate modifications, as well as the experience gained by state oil and natural gas regulatory agencies in this regard, can be applied to the storage of CO_2. Existing regulations address issues such as facility design, construction, and operation; storage cavern mechanical integrity; acceptable operating pressures and conditions; verification of stored volumes; design, drilling, and operation of injection wells, including mechanical integrity; surface facilities; and general safety and environmental concerns, among others.

Salt caverns for natural gas storage are typically developed in thick-bedded salt strata or in salt domes (structures formed from the upwelling and upward piercement of salt from depth) through solution mining. Geologic salt formations have characteristics that render them highly suitable for storage operations. Salt formations (comprised of the mineral halite – NaCl) are generally impermeable at typical storage pressures, have compressive strength comparable to concrete, and are self-sealing, owing to their plastic nature, resulting in a strong, safe, and reliable storage environment. Often, pores in strata adjacent to salt deposits are effectively plugged with crystalline salt, further impeding the movement of gas and fluids out of the storage cavern. Salt is easily and economically mined, using fresh water as a solvent. Figure 2.3.3-1 is a diagram illustrating salt cavern storage, as well as a breakdown of areas of state and federal regulation in natural gas production and storage.

[28] Natural Gas Storage in Salt Caverns, A Guide for State Regulators, Interstate Oil and Gas Compact Commission, Energy Resources Committee 1995.

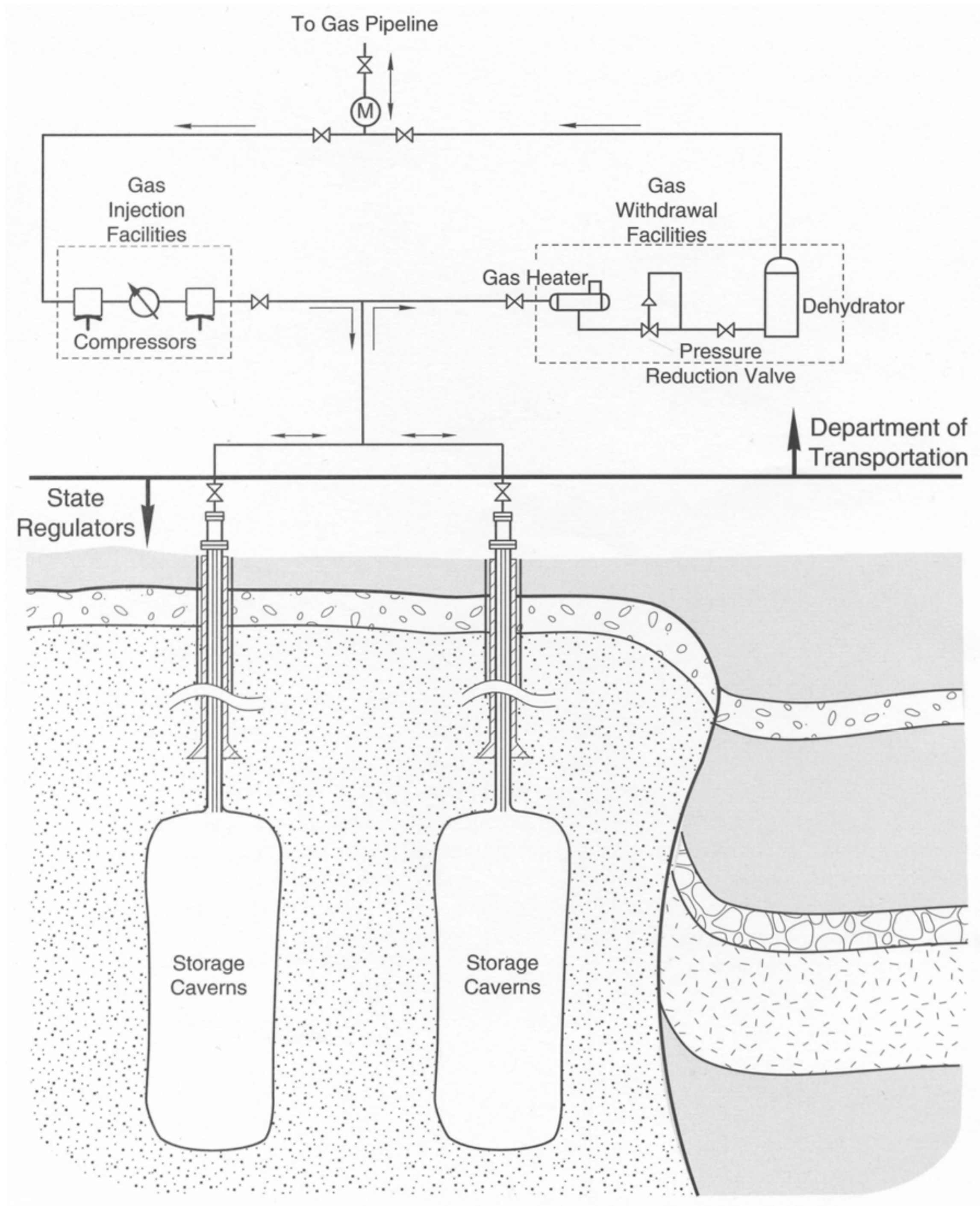


Figure 2.3.3-1 Diagram of Salt Cavern Storage and Breakdown of Areas of State and Federal Regulations. [29]

---

[29] Energy Resources Committee, Interstate Oil and Gas Compact Commission, Natural Gas Storage in Salt Caverns, A Guide for State Regulators, p. 11, 1998.

Salt cavern storage is based on technologies and industrial practices with a long history of safe, effective, efficient, and environmentally sound operations. These technologies and practices, and the rules and regulations that govern them, are readily adaptable to the storage of CO_2. The cost of salt cavern storage is presently prohibitive relative to other options; consequently relatively little research on salt cavern storage is currently taking place.

2.3.4 Coalbed Storage

Coalbeds also provide a potential geologic storage option for CO_2 through adsorption. Methane is chemically adsorbed on coalbeds to varying extents, depending on coal character (maceral type, ash content, etc.), depth, basin burial history and other factors, and has been produced to an ever greater extent over the last decade to add to the nation's natural gas supply. Coalbed methane (CBM) currently comprises 8% of the total U.S. natural gas production and 10% of the total U.S. natural gas reserves.[30] Major sources of CBM have been the San Juan, Black Warrior, and Powder River basins, with additional resources coming from other Rocky Mountain basins, the Mid-continent, and the Appalachian Basin. Injection of CO_2 has been tested in the San Juan Basin for enhanced CBM production.[31] In one pilot project in West Virginia, DOE currently has undertaken with Consol to test adsorption of CO_2 on coals specifically for storage purposes using a set of horizontal wells. The expectation for this project, among other similar experiments and with the support of laboratory testing, is that the adsorption sites on the coal matrix surface have stronger affinity for the CO_2 than the methane and would retain CO_2 and liberate producible methane. Injection of CO_2 for the purpose of enhanced CBM production would not be defined as storage if the coals will be mined in the future, thereby liberating the adsorbed CO_2. Coals deemed economically unminable due to depth, limited thickness, or other factors would be the only coals potentially suitable for storage. A DOE-supported enhanced CBM production test at the Allison Unit in

---

[30] Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, September 2004, DOE/EIA-0216(2003), at: http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2003/adsum2003.pdf

[31] Allison Project Report by Advanced Resources International.

New Mexico has been completed and is in its post-injection phase. It has demonstrated recovery of 1 scf of methane per 3 scf of injected CO_2.[32]

2.4 Mature Oil and Natural Gas Fields As Pathways to CCGS

An excellent working model for CCGS is the injection of CO_2 into mature oil fields that have evolved through their primary and secondary (waterflooding) phases of production. Injection of CO_2 for EOR has been in practice for the past three decades, most widely in the Permian Basin of west Texas and southeast New Mexico. The technical and economic success of this form of tertiary recovery is widely accepted as "standard oil field practice" and is being studied and expanded in the U.S. and abroad. It is important to note that during EOR operations CO_2 is not released into the atmosphere but is captured, separated and recycled back into the reservoir to recover additional oil.

It should be emphasized that CO_2 used in EOR projects has a clear value to the oil industry and as such has commodity status within the industry infrastructure currently required to handle 2.9 billion cubic feet per day (bcfd) of CO_2 (approximately 155,000 Mt per day or 56.6 Mt per year). The regulatory framework developed for CO_2 EOR will provide a valuable starting block for CCGS regulatory structure. Perhaps most important though, by utilizing CO_2 for EOR in new areas of the U.S. and the world, the CO_2 EOR process can provide the commercial drivers for building much of the necessary infrastructure to transport CO_2 from sources to the sinks.

In 2000, 34 Mt of CO_2 were injected underground as part of EOR operations in the United States. This is roughly equivalent to the CO_2 emissions from 4.7 million cars in one year.[33] For CO_2 EOR, 6,000-10,000 scf of CO_2 are typically injected per

---

[32] U.S. Department of Energy, Topical Report: The Allison Unit CO_2-ECMB Pilot Project: A Reservoir Modeling Study, January 1, 2000 – June 30, 2002.
[33] Number derived from Information Card, U.S. Greenhouse Gas Facts, *Global Climate Change Technology Initiative*, NETL Carbon Sequestration Program.

barrel (bbl) oil recovered.[34] Most EOR projects in the U.S. are miscible floods wherein pressure and temperature in the reservoir are such that CO_2 and oil fully mix. At shallower depths, generally less that 2,500 ft, CO_2 and oil are immiscible and the recovery process may not be as efficient, yet may still be economical, depending on the cost of delivering CO_2 to a field and the volume of unrecovered oil remaining in the reservoir.[35] Larger fields that have a significant unrecovered oil resource would most likely justify the costs of surface facilities, of drilling or refurbishing of wells to accommodate CO_2 injection, and of the reservoir studies necessary to develop an efficient CO_2 EOR process.

Additionally, CO_2 could potentially enhance natural gas recovery (EGR) by being used to maintain pressure in depleting natural gas fields and also could potentially provide cushion gas if a reservoir were later to be converted to natural gas storage. Modeling has shown the potential for injection of CO_2 for up to a decade before breakthrough.[36] There are many other reservoir factors that will dictate the success of EGR projects. At the present time there are no active EGR projects. However, as this industry evolves, CO_2 pipelines will be constructed and this infrastructure will lay the foundation for future CCGS.

2.5 The History and Use of CO_2 for Enhanced Oil Recovery

The required components of CO_2 injection have been developed and enhanced for more than 30 years, primarily within the Permian Basin oil and natural gas producing and regulatory communities. This operation is depicted in Figure 2.5-1. Carbon dioxide has been used effectively as an injectant to increase oil production within the Permian Basin region of west Texas and southeast New Mexico since 1972 and many other regions since the early 1980s. With the development of the commercial

---

[34] Practical Aspects of CO2 Flooding, SPE Monograph, November 2002.
[35] Mohammed-Singh, L. and Singhal. A. , "Lessons from Trinidad's CO_2 Immiscible Pilot Projects 1973-2003", Paper #89364, presented at the 14th SPE/DOE Conference on Improved Oil Recovery, April 2004.
[36] Oldenburg, Curtis M., "Carbon Sequestration in Natural Gas Reservoirs: Enhanced Gas Recovery and Natural Gas Storage". Paper No. LBNL-52476, Lawrence Berkeley National Laboratory, Berkeley, California, April 8, 2003. http://repositories.cdlib.org/lbnl/LBNL-52476

application of CO_2 to oil recovery, much research and practical experience has been gathered.[37]

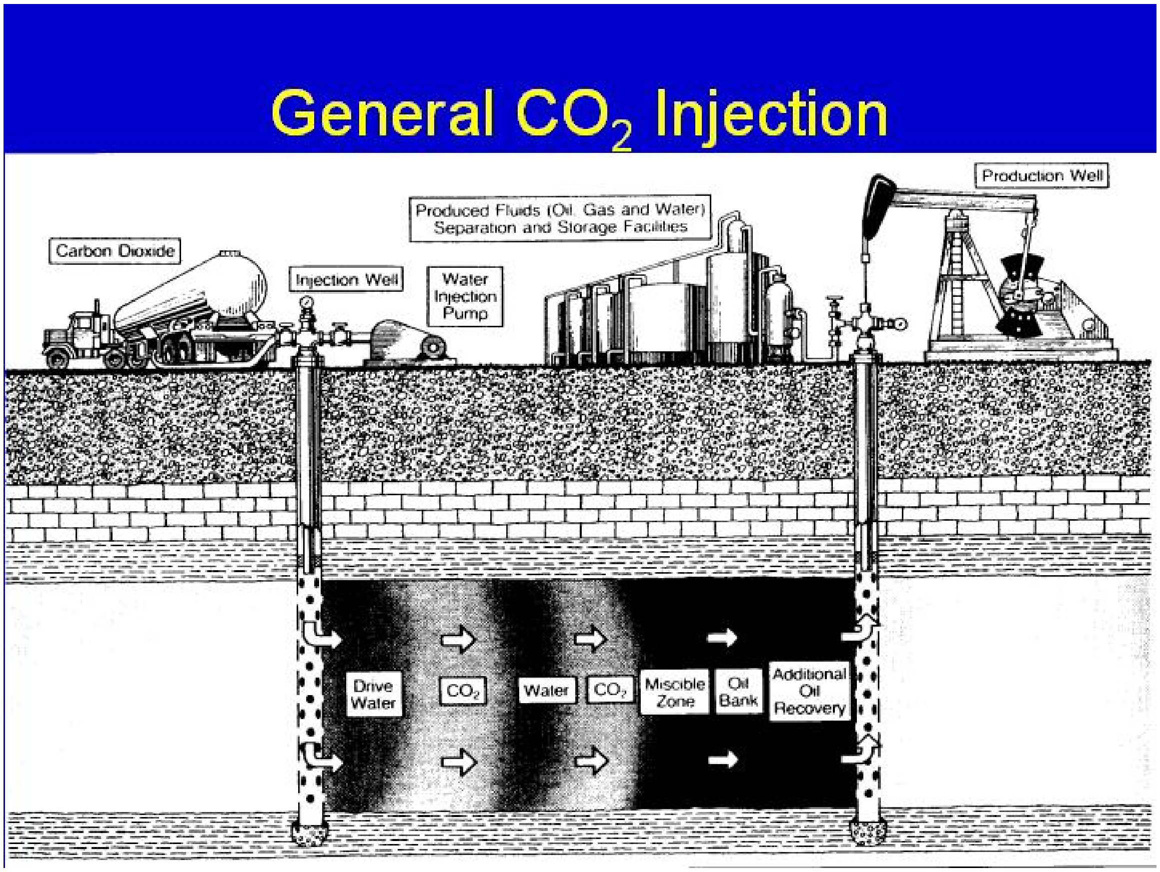


Figure 2.5-1 General CO_2 Injection.[38]

[37] Practical Aspects of CO_2 Flooding, SPE Monograph, November 2002.
[38] Illustration courtesy of the Midwest Geological Sequestration Partnership (Illinois Basin), 2004.

The utilization of CO_2 as an injectant into oil reservoirs for producing incremental oil began as early as the 1950s.[39] Those early experiments went largely unnoticed until the early 1970s when two large-scale floods in the Permian Basin region of west Texas were developed for commercial reasons. Those floods were supplied CO_2 from anthropogenic sources via the first long distance CO_2 pipeline, the Canyon Reef Carriers (CRC) pipeline. The CRC connected several natural gas processing plants in the southern Permian Basin with Shell's North Cross flood in Pecos County and the huge SACROC flood in Scurry County, Texas.

CO_2 floods utilize both new and recycled CO_2 in the EOR process, confirming the commodity value of CO_2. The typical price for new CO_2 ranges from $0.50/mcf to $1.00+/mcf. The components of cost include gathering, drying, purification, compression, and pipeline transportation. Recycling of CO_2 from the return flow of producing wells is economical because, even after treatment, this cost is generally less than one-half the cost of purchasing and transporting new CO_2.

As of 2004, there were 78 CO_2 EOR operations worldwide and 70 in the U.S., primarily in the Permian Basin of west Texas.[40] Within the U.S. during 2003, 1.5 billion cubic feet per day (bcfd) or 28 Mt[41] per year of new CO_2 were injected and an estimated 1.4 bcfd were recycled during EOR operations. Taken together, these new and recycled streams of CO_2 were responsible for recovering more than 55 million barrels of annual crude oil production. Figure 2.5-2 shows the recent project and production history of CO_2 flooding in the Permian Basin, which is responsible

---

[39] See: "How Carbon Dioxide Floods Stack up with Conventional Waterfloods", Oil and Gas Journal, July 16, 1962 (Carbonated Waterfloods); "Summary Report of CO_2 Flood Test at Mead-Strawn Field", Union Oil of Calif., Internal Report, Nov, 1968 (Hybrid WAG; Immiscible); "Carbon Dioxide Test at the Mead-Strawn Field", L. W. Holm & L. J. O'Brien, Journal of Petroleum Technology, April, 1971; "Performance of Domes Unit Carbonated Waterflood-First Stage", J. O. Scott & C. E. Forrester, Journal of Petroleum Technology, December, 1965 (Carbonated Waterflood); "Carbonated Waterflooding: Is it a lab success and a field failure?", N.H. de Nevers, World Oil Magazine, September 1966; "Experience with CO_2 EOR Process in Hungary", G. Nemeth, J. Papay & A. Szittar, Presented at 4th European Symposium on EOR, Hamburg, October 1987 and revised in Revue de l'Institut Francais de Petrole, Vol. 43, No. 6, November-December, 1988.
[40] The Oil and Gas Journal Survey of EOR Projects, April 12, 2004.
[41] See footnote 14.

for 71% of the CO_2 floods and 84% of the CO_2 EOR barrels of oil produced in the United States. The chart shows a significant number of projects, the substantial contribution of these projects to energy production, and the growth trend over the last 20 years.

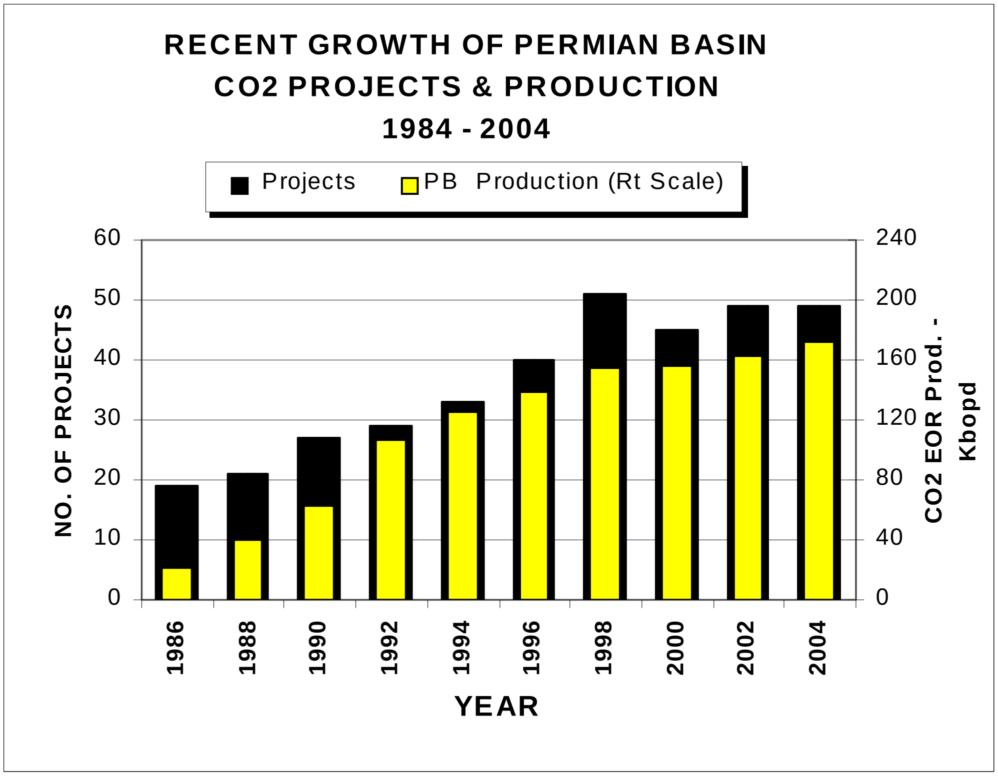


Figure 2.5-2 Recent Growth of Permian Basin CO_2 Projects & Production 1984-2004.[42]

The majority of new CO_2 utilized in the U.S., including Permian Basin CO_2 floods, comes from three naturally occurring CO_2 source fields, Sheep Mountain, Bravo Dome, and McElmo Dome. (See Figure 2.5-3). The underground source fields have the desired properties of day-to-day reliability along with high purity (>95% CO_2) and high pressure CO_2 in large volumes. Similarly, pure anthropogenic sources of CO_2 were available, although in relatively low volumes, and had occasional reliability issues and required substantial compression to reach pipeline operating pressures (1,800-2,200 psi). These industrial (anthropogenic) sources of CO_2 were used (and continue to be used today) in the SACROC, North Cross and other

[42] The Oil and Gas Journal Survey of EOR Projects, April 12, 2004.

projects, but have become relatively minor source contributors as the natural source fields with large and reliable volumes available were able to be connected to new CO_2 floods. Anthropogenic sources of CO_2 have become commercial in areas outside the Permian Basin in Wyoming, North Dakota, Michigan, and Kansas, and are projected to be a major source for future CO_2 floods.

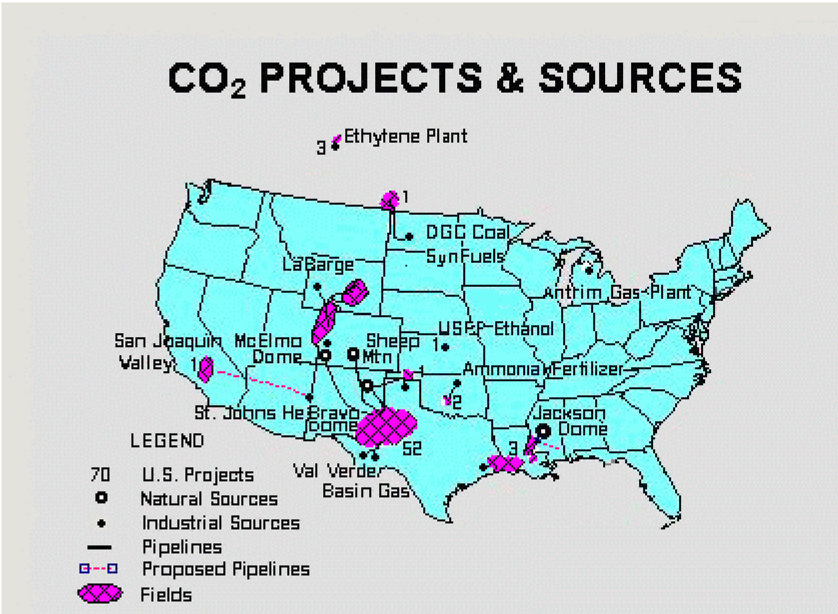


Figure 2.5-3 CO_2 Projects & Sources.[43]

In addition to the large knowledge base which has been developed for CO_2 EOR projects, a similar CO_2 transportation knowledge base has been developed. High-pressure CO_2 pipelines for short and long hauls are widely used in the CO_2 EOR industry. It is estimated that more than 3500 miles of high pressure (>1,300 psi) CO_2 pipelines have been constructed in the U.S. since 1971. In total, approximately 4 bcfd of CO_2 are handled by the nearly 30,000 persons who operate the plants, pipelines, injection, and producing wells associated with existing CO_2 projects.[44] EOR operations have an enviable safety record with no major accidents occurring over their 33-year history.

---

[43] Created by Melzer, L.S, 2004.
[44] "Permian Basin Drives CO_2 Technology," Melzer, L.S. and Stiles, L.H., American Oil and Gas Reporter, Permian Basin Oil Show Program Edition, Vol 39, No. 10, October 1996, pp. 149-152.

Carbon dioxide EOR projects will lay the foundation for CCGS by providing expansion of the CO_2 pipeline infrastructure, expansion of the knowledge base, continued development of CCGS technologies, and the necessary economic incentives through increased domestic oil and natural gas production. Consequently, CO_2 EOR is likely to continue to provide new and improved technologies and an expanding infrastructure for CCGS. Today's energy producers can be strong contributors to mitigating the impact of fossil fuel consumption necessary to fuel our modern economy by providing critical pathways to CCGS.

2.6 Acid Gas Injection -- Regulatory Experience in U.S. and Canada

As mentioned previously, another commercial-scale analogue to geological CO_2 storage is the injection of acid gas, a combination of H_2S and CO_2. H_2S is an impurity associated with some oil and natural gas production. The safe removal, transportation, and injection of this impurity demonstrate the ability to safely regulate and handle a gas, which unlike CO_2, is overtly hazardous.

Acid gas is a by-product of processing streams of sour natural gas and oil. Processing to remove acid gas is necessary to meet pipeline and market specifications. Because flaring of acid gas is not permitted by regulatory agencies except for very small quantities of H_2S, and because surface desulfurisation is uneconomical in a depressed sulfur market and the surface storage of the produced sulfur constitutes a liability, increasingly, operators in Canada and the U.S. are turning to acid gas disposal by injection into deep geological formations. Compared to other options, acid gas injection has less environmental consequences than sulfur recovery (where leaching of the sulfur piles can lead to groundwater contamination) or flaring (which essentially substitutes sulfur dioxide (SO_2) for H_2S in the atmosphere, as well as releasing CO_2). Although the purpose of the acid gas injection operations is to dispose of H_2S, significant quantities of CO_2 are being injected at the same time because it is neither beneficial nor necessary to separate the two gases.

Acid gas is injected into deep saline aquifers and depleted oil or natural gas reservoirs at 44 locations in Alberta and British Columbia in Canada, and at close to 20 sites in Michigan, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming in the United States. In Canada, a total of 2.5 Mt CO_2 and 2 Mt H_2S have been injected by the end of 2003, at rates that vary between 840 and 500,720 cubic meters per day per site, with a cumulative injection rate in 2003 of 0.45 Mt/year CO_2 and 0.55 Mt/year H_2S. Injection depths vary between 3,000 and 11,000 feet.

In the United States, "there have been no known incidents where significant harm has occurred as a result of an acid gas injection operation".[45] In Canada, no safety incidents have been reported since the first acid-gas injection operation began in 1990. These acid-gas injection operations represent a commercial-scale analogue to geological storage of CO_2. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., design, materials, leakage prevention, and safety) can be easily adopted for large-scale operations for CO_2 geological storage, since a CO_2 stream with no H_2S is less corrosive and non-hazardous.

[45] Heinrich, J.J., Herzog, H.J., and Reiner, D.M., Environmental Assessment of Geologic Storage of CO_2, Publication No. LFEE 2003-002 Report, Prepared for Clean Air Task Force, December 2003, Revised March 2004. The authors state that this is the case "[d]espite H_2S being much more toxic that CO_2."

3. Chapter 3 – Regulatory Overview

In the United States and Canada, onshore regulation of oil and natural gas production and natural gas storage is under the jurisdiction of the states and provinces.[46] State and provincial oil and natural gas regulatory programs and state and provincial oil and natural gas regulatory storage programs have kept pace with the evolution and technological advancements of the oil and natural gas industry over the last 90 years, which has included the injection of CO_2 for EOR and the underground storage of natural gas. The state/provincial regulatory frameworks, which currently govern the use of CO_2 for EOR and underground natural gas storage, are well established. (For a compendium of current state and provincial regulatory frameworks for CO_2, see Appendix 2).

In the case of EOR, the transportation by pipeline from the source to the project site and the drilling and operation of wells is governed by state and provincial regulations. For example, the Texas Railroad Commission, especially Districts 8 and 8A, have now had 30 years of experience in regulating CO_2 EOR and related transportation facilities. Other states and provinces, including New Mexico, Oklahoma, Wyoming, Michigan, Mississippi, North Dakota, and Alberta also have significant regulatory experience, including monitoring for health, safety, and environmental effects during the processing, transportation, and injection of CO_2.

In the case of underground storage of natural gas, the transportation by pipeline from the source of the natural gas to the storage site, as well as the drilling and operation of wells and the establishment of storage site operational parameters, are currently regulated by federal, state, and provincial regulations. In the U.S. there are currently 450 permitted underground natural gas storage projects in 35 states as shown in Figure 3.0-1, injecting and storing approximately 140 Mt annually. The natural gas

[46] States also have regulatory jurisdiction offshore although the limits of that jurisdiction vary by state.

storage industry has more than 80 years experience with underground storage technology.[47]

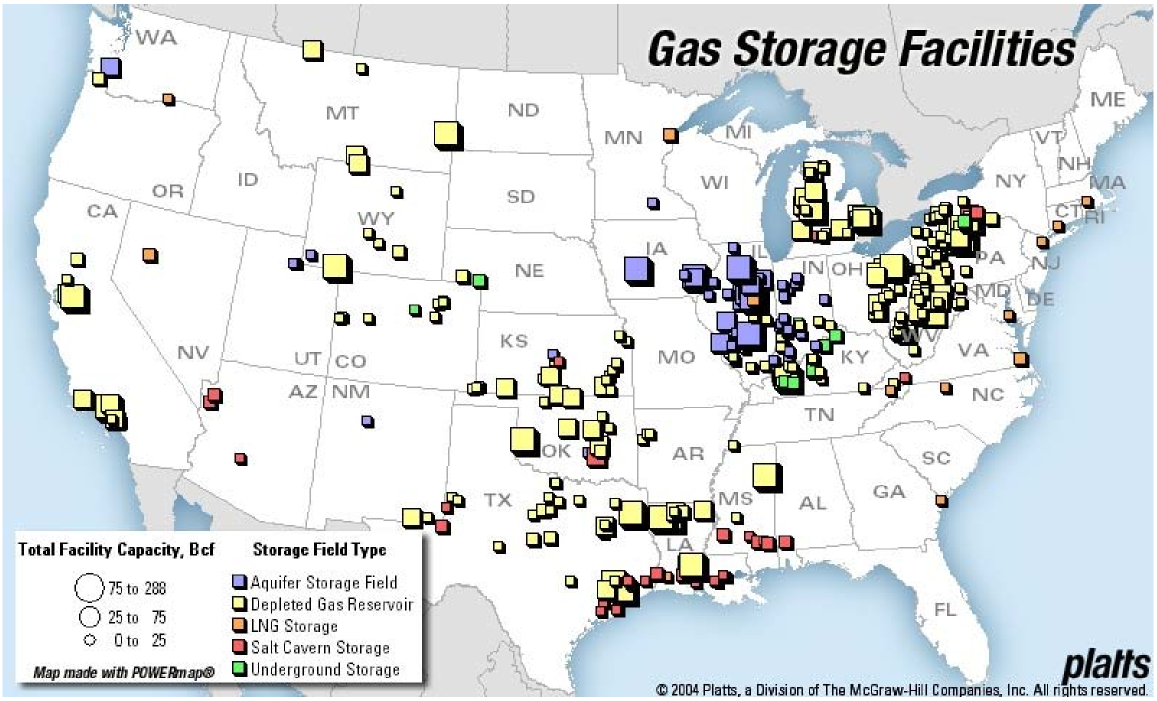


Figure 3.0-1 Gas Storage Facilities.[48]

The process of CCGS consists of 4 components, each of which has technical issues and regulatory frameworks necessary to fully address all the issues that comprise a CCGS regulatory scheme. For the purposes of this report, these components are divided into capture, transportation, injection, and storage. Each state and province has regulatory frameworks in place covering each of these elements with the exception of long-term storage. This report will attempt to analyze in a general way

[47] "The use of underground gas storage facilities in the natural gas industry is almost as old as the development of long distance [natural gas] transmission lines. The first high pressure [natural gas] transmission lines began operations in 1891 with successful construction of two parallel 120-mile, 8-inch diameter lines from fields in northern Indiana to Chicago. The first successful [natural] gas storage project was completed in 1915 in Welland County, Ontario. The following year, operations began in the Zoar field near Buffalo, New York." From FERC Staff report issued on current state of and issues concerning underground natural gas storage and announcement of technical conference on October 21, 2004, at http://www.ferc.gov/EventCalendar/Files/20040930183109-Final%20GS%20Report.pdf.

[48] The map was prepared by and is used with the permission of Platts.

the regulatory gaps between the present regulatory structure and that needed to implement a CCGS regime in each of the 4 areas identified above.

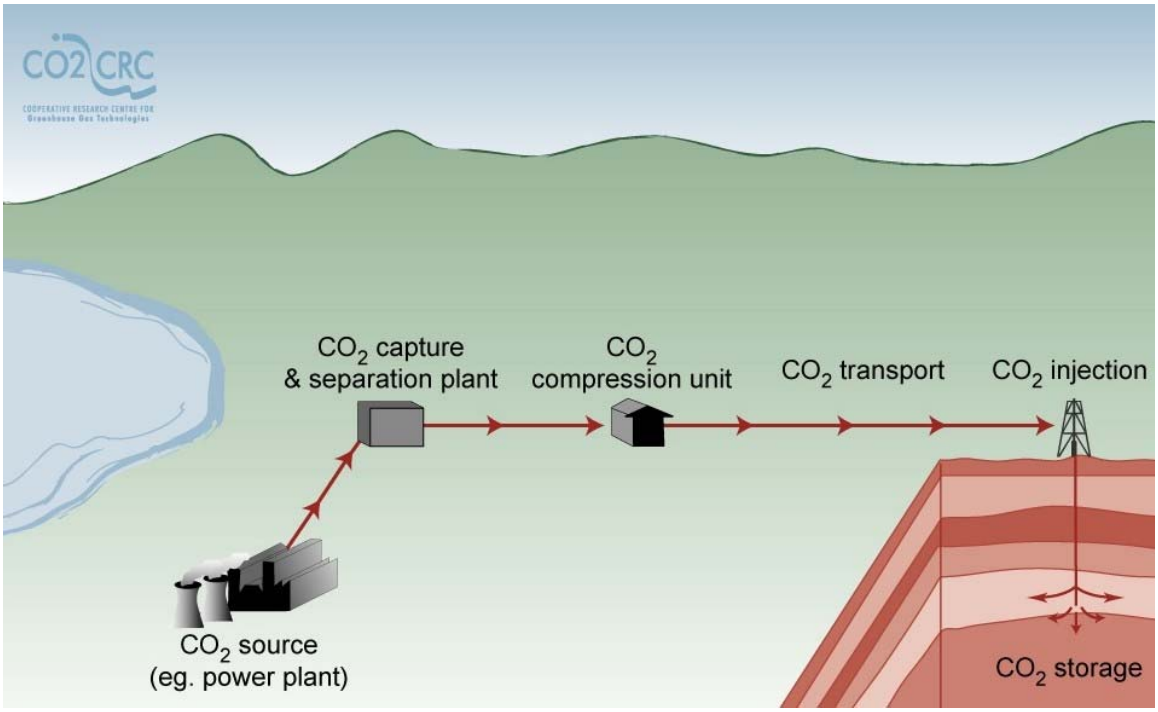


Figure 3.0-2 Carbon Dioxide Capture & Storage Project Life Cycle.[49]

3.1 Capture

The capture of industrial or anthropogenic CO_2 can be defined as the process of gathering, drying, purifying, and compressing the CO_2 stream to allow transportation to a market, EOR operation, or storage site. There are 4 technologies currently available for CO_2 capture from anthropogenic sources, which incorporate the process of gathering, drying, and purifying. These are most often combined in one or more physical or chemical processes such as glycol adsorption, membrane separation or amine adsorption as shown in Figure 3.1-1. Each of these technologies has advantages and disadvantages that impact the relative cost of CO_2 capture. Capture costs are a function of the capture technology employed, CO_2 composition of the

[49] The diagram was prepared by and is used with the permission of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), Australia.

emissions stream, and energy consumed during the capture process. Emission streams with low CO_2 concentrations and low pressure are the most costly to capture.

Capture technologies are currently being employed in the oil and natural gas industry. It is estimated that 27 million Mt per year of CO_2 are captured by approximately 40 natural gas processing plants in the Permian Basin region alone.[50] Given that the largest cost component of CCGS is capture technology, much research is being devoted to improvements in both optimizing current technologies and developing new technologies to reduce capture costs. As history has shown us, CO_2 capture costs are projected to decrease in the future, as they will be applied on a large scale along with technological improvements.

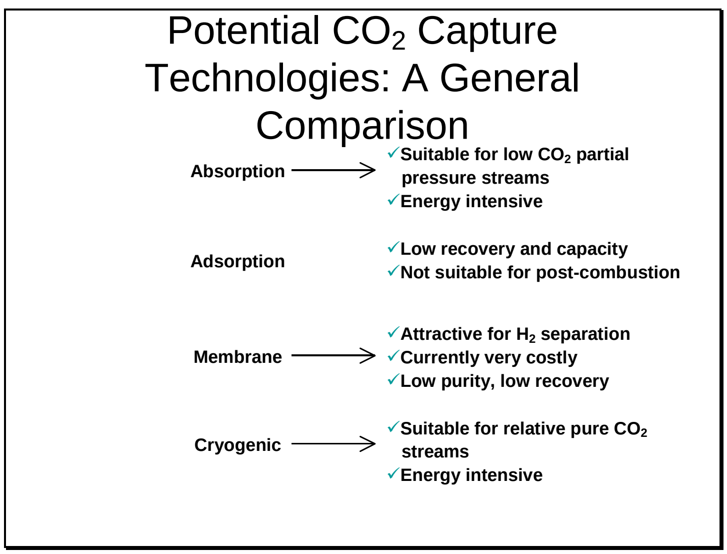


Figure 3.1-1 Potential CO_2 Capture Technologies: A General Comparison.[51]

[50] Compiled by Melzer, L.S. from Personal Data Files 2004.
[51] Illustration courtesy of the Midwest Geological Sequestration Partnership (Illinois Basin), 2004.

3.1.1 Capture Technical Issues

CO_2 is a byproduct of numerous industrial processes and fossil fuel utilization. These various sources result in the generation of varying concentrations of CO_2 in their emission streams. The chart below shows that the largest volume of CO_2 emissions is contained in highly dispersed sources which do not lend themselves to CCGS. The sources at the top of the pyramid, although small in volume, have the advantage of point source generation and high purity concentration – greater than 95% – which is the minimum requirement for pipeline transportation. Consequently those sources are the best economic candidates for CCGS. The sources at the middle of the pyramid – for example electric generation – will require costly capture technologies, but would supply substantial quantities of CO_2.

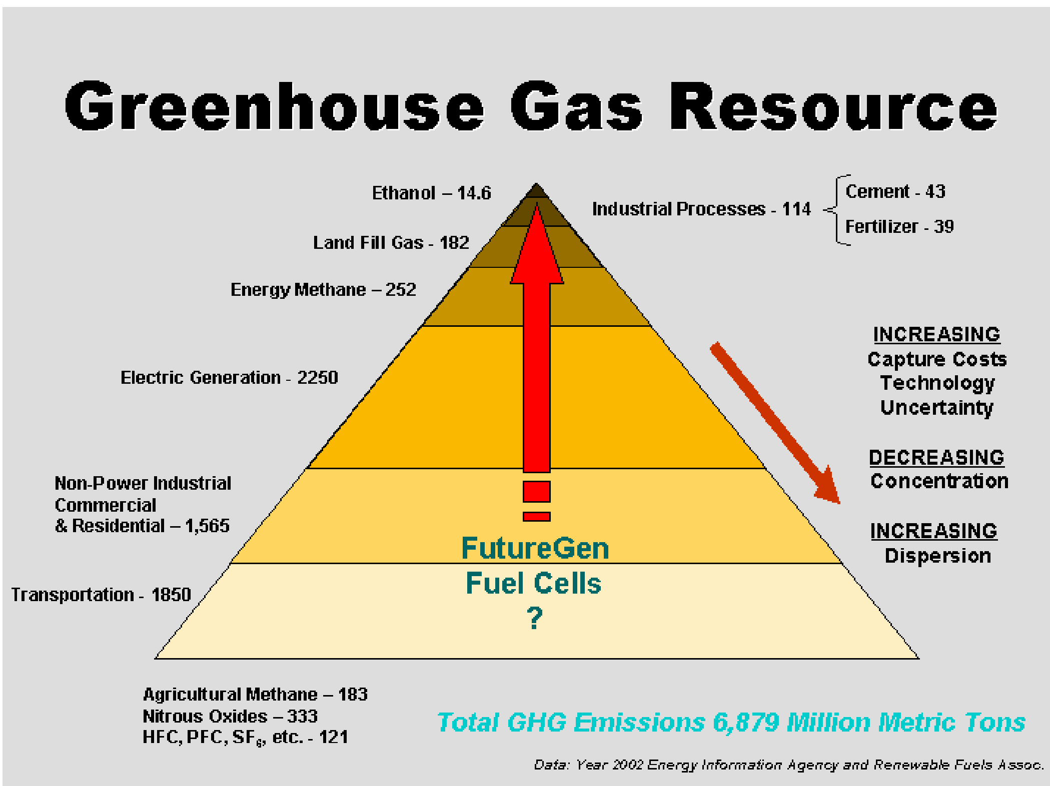


Figure 3.1.1-1 Greenhouse Gas Resource.[52]

---

[52] Carr, Timothy R., Alan P. Byrnes, Martin K. Dubois, and Scott W. White, Models for Environmentally Sound and Economically Viable Carbon Dioxide Sequestration Opportunities, AAPG Annual Meeting, Dallas, Texas - April 18-21, 2004, p. A21, and Kansas Geological Survey Open-File Report 2004-19: http://www.kgs.ku.edu/PRS/publication/2004/AAPG/CO2/ofr2004-19.pdf

The separation of CO_2 from these less pure emission streams, which may contain other constituents such as oxides of sulfur and nitrogen (SO_X and NO_X), H_2S, and water (H_2O), involves many established, innovative, and developing capture technologies with associated costs that impact the economics of capture. A large body of literature is available concerning existing and developing capture technologies and associated costs. A list of DOE/NETL CO_2 capture technology literature can be found in Appendix 3. Because of the relatively high costs of capture and the unknown affects of these impurities on transport and reservoir integrity, this report will only address the relatively pure streams of CO_2 which are readily available for injection and storage. For purposes of this report, CO_2 for CCGS is defined as a direct emissions stream with purity in excess of 95% or a processed emission stream with commercial value. Given that CO_2 currently has many established industrial and EOR uses, value for CO_2 has been clearly established, therefore defining CO_2 as a commodity.

3.1.2 Capture Regulatory Recommendations

Many state/provincial and federal regulations dealing with emissions from industrial and energy generation facilities exist today in the United States and Canada. The Task Force notes that these regulations do not, for valid reasons, classify CO_2 as a pollutant, waste, or hazardous substance, and with few minor exceptions at the state level, do not regulate CO_2 emissions into the atmosphere.[53] Worldwide, some nations, in response to concern over global climate change, have put into place regulatory imperatives that limit CO_2 emissions. While the United States has not yet promulgated any regulations covering CO_2 emissions, under its *Global Climate Change Initiative,* the U.S. has set a goal to reduce greenhouse gas intensity 18% by

---

[53] The EPA, in response to a petition asking that it regulate certain greenhouse gas emissions under the Clean Air Act (CAA), concluded in a September 2003 Notice of Proposed Consent Decree that "[b]ased on a thorough review of the CAA, its legislative history, other congressional action and Supreme Court precedent, EPA believes that the CAA does not authorize regulation to address global climate change." 68 Fed. Reg. 52922, 52925 (September 8, 2003).

2012 through encouraging voluntary efforts by industry. Under such a voluntary system, the development of CCGS projects in the U.S. likely will be limited, beyond the use of relatively pure streams of CO_2 that prove to be economical for use in CO_2 EOR projects. This scenario could change, however, with the introduction of emission caps, economic incentives (tax and otherwise), and/or advances in technology that reduce capture costs.

Regulations for CO_2 have been promulgated by various agencies. The Occupational Safety and Health Administration (OSHA) has set time/concentration limits for exposure in confined spaces. To address ventilation and indoor air quality, other agencies such as the Federal Aviation Administration (FAA), Federal Emergency Management Agency (FEMA), the National Institute for Occupational Safety and Health (NIOSH), and others have set CO_2 limits for specific circumstances and environments.

The Task Force has concluded that given the substantial regulatory framework that currently addresses emissions standards there is little need for state regulatory frameworks in this area. Specific recommendations are set forth below.

- Existing federal air regulations do not define CO_2 as a pollutant. There is no need for state regulation to do otherwise. However, states which may have already defined CO_2 as a waste, air contaminant, or pollutant, may be advised to reassess that definition so as to not negatively impact CCGS development. While contaminants and pollutants such as NO_2, SO_2 and other emission stream constituents should remain regulated for public health and safety and other environmental considerations, CO_2 is generally considered safe and non-toxic and is not now classified at the federal level as a pollutant/waste/contaminant, and should continue to be viewed as a commodity following removal from regulated emission streams.
- Devise standards for measurement of CO_2 concentration at capture point to verify quality necessary for conformance with CCGS requirements.

- Involve all stakeholders, including the public, in the rule making process at the earliest possible time.

3.2 Transportation

For the purposes of this report, transportation is defined as the process of moving pressurized CO_2 via pipeline, tank transport, or ship from capture of the CO_2 (following processing, gathering, and compression) to the site of injection.

3.2.1 Transportation Technical Issues

The long distance transport of CO_2 has seen technological advancement but it is primarily concentrated in construction methods. There are currently 3 main modes of pipeline transportation of CO_2. These transmission modes are: 1) high pressure dense or supercritical phase transmission (above 1,180 psi); 2) lower pressure gas transmission (gas phase); and 3) refrigerated liquid transmission.

Existing long distance pipelines and those being built today fall into transportation mode 1 above and are all constructed with conventional carbon steel. They transport CO_2 in the dense or supercritical phase. The CO_2 is dried to eliminate concerns of possible corrosion with formation of carbonic acid when water is present. Gathering pipelines constitute mode 2 above and often contain water, requiring mitigation such as the use of fiberglass or plastic coating to avoid corrosion. Construction and operational safety regulations exist and are administered by the U.S. Department of Transportation's Office of Pipeline Safety (OPS) consisting of a large base of experience. States may also regulate under partnership agreements with OPS. Transportation mode 3 generally refers to rail or truck transport that is in widespread use in the marketplace serving the food and beverage industries, specialty gas industry, and the oil and natural gas hydraulic fracturing business.

There are many CO_2 pipelines currently in operation that provide a large knowledge base on construction and operational standards. A list of all major North American CO_2 pipelines can be found in Appendix 4. Some of the major pipelines are also shown graphically on Figure 2.5-3. These pipelines are regulated by OPS.[54] The oldest of the long distance pipelines was recently required by the OPS to undergo an inspection and pressure test. This Canyon Reef Carriers pipeline, 138 miles in length, was constructed in 1971 by Gulf Oil Corporation and is now operated by Kinder Morgan CO_2 Company, L.P. The hydrotesting of this A-CO_2 pipeline was recently reported[55] and resulted in re-rating of the line to its original 1,800 psi internal pressure rating.

Many state, provincial, and federal regulations exist in the United States and Canada to deal with transportation design, construction, operations, maintenance, and emergency response for spills. In addition, groups such as the American Petroleum Institute (API), the American Gas Association (AGA), and the American Society for Testing and Materials (ASTM) have established standards for pipeline construction and material selection. These well-established regulations and pipeline construction and material standards will adequately address CO_2 transportation.

The only federal agency with regulatory responsibilities for interstate natural gas pipelines, other than OPS whose regulatory responsibilities deal mainly with safety, is the Federal Energy Regulatory Commission (FERC). FERC issues involve rate structure, gas storage facilities, certificates of public convenience, open access, facility abandonment, and environmental review. FERC has jurisdiction only with transportation involving interstate commerce. States regulate intrastate commerce. FERC presently has no legislative authority to regulate interstate CO_2 pipelines.[56]

---

[54] 49 CFR Parts 190-199

[55] "Results of the Hydrotest of the 30-year old Canyon Reef Carriers CO2 Pipeline," Layne, J, 2003 CO2 Flooding Conference, December 11-12, 2003, Midland,Texas (Univeristy of Texas of the Permian Basin's Center for Energy and Economic Diversification.

[56] Any legislation granting FERC authority over CO2 pipelines would presumably require that the transport of CO2 be considered interstate commerce and it would follow that CO2 be considered a commodity.

Unresolved state and federal issues with interstate CO_2 pipelines include eminent domain[57] and the potential need for federal, presumably FERC, authority over such pipelines as well as the subsidiary issue of open access.[58] CO_2 pipeline construction potentially will require exercising eminent domain, which is largely a state issue.[59] Existing state eminent domain statutes need to be reviewed to determine if CO_2 meets the requirements necessary to allow the use of eminent domain authority for CO_2 pipeline construction. Because they are legal issues beyond the scope of this report, they are noted for future consideration by the states.

3.2.2 Transportation Regulatory Recommendations

There are numerous parallels between CO_2 transport and natural gas transport. In fact, most rules and regulations written for natural gas transport by pipeline include CO_2 and are administered and enforced by the DOT, OPS. These rules are designed to protect the public and the environment by assuring safety in pipeline design, construction, testing, operation, and maintenance. State/federal partnership programs exist whereby states can assume all or part of OPS regulatory and enforcement responsibilities. State jurisdiction usually covers the smaller diameter, lower pressure pipelines associated with gathering facilities in oil and natural gas fields. Where CO_2 transport is by rail, road or ship, other rules, regulations, and agencies may have jurisdiction.

Consequently, given the large body of experience in pipeline operation, including CO_2 pipelines, well established regulatory frameworks, and well established materials and construction standards, there is little necessity for additional state

---

[57] Eminent domain is defined as "[t]he power of a governmental entity to convert privately owned property, especially land, to public use, subject to reasonable compensation for the taking." Black's Law Dictionary, Bryan A. Garner, Editor-in-Chief, West Publishing Co. 1996.

[58] Open access refers to a regime or system under which competition in the pipeline transportation industry is fostered by "the 'unbundling' of the [pipeline companies'] transportation and merchant roles, thus allowing pipelines to provide transportation service for customers who bought gas elsewhere and had it shipped through the pipelines' transportation system." Northwest Pipeline Corporation v. Federal Energy Regulatory Commission, 61 F.3d 1479, 1482 (10th Cir. 1995).

[59] In the case of interstate natural gas pipelines, the Natural Gas Act also gives pipeline companies authority under certain conditions to bring condemnation proceedings in federal court although the federal court will apply the applicable state law. The Natural Gas Act of 1938, as amended, 15 USC 717-717W.

regulations. The Task Force recognized in its discussions that the issues of open access and the potential need for FERC jurisdiction over CO_2 pipelines might be issues that need to be addressed at the state and federal level in the future. Specific recommendations are set forth below:

- Require clarity and transparency in any potential statute and regulation development.
- For transportation of CO_2 by pipeline, utilize regulatory structures from existing DOT, OPS and state rules and regulations governing CO_2 pipeline construction, operation, maintenance, emergency responses, and reporting.
- Include CO_2 in your state's "call before you dig" protocol.
- In development of state permitting procedures, identify areas of special concern such as heavily populated areas and environmentally sensitive areas so that additional safety requirements can be considered.
- While the "open access" issue is ultimately a federal concern, states must be aware of the relevancy of the open access issue as it affects state regulatory responsibilities.
- Review existing state eminent domain statutes to determine if CO_2 meets the requirements necessary to allow the use of state eminent domain authority for CO_2 pipeline construction. Clarify state eminent domain powers affecting the construction of new CO_2 pipelines while respecting private property rights.
- Identify opportunities for use of existing rights of way, both pipeline and electric transmission, for transportation of CO_2.
- Allow for CO_2 transportation in pre-existing pipelines used to transport other commodities providing that safety, health, and environmental concerns are addressed.
- Involve all stakeholders, including the public, in the rule making process at the earliest possible time.

3.3 Injection

Injection is defined as the placement, through wells, of CO_2 under pressure into underground geological formations.

3.3.1 Injection Technical Issues

There are four primary options for the geologic storage of CO_2 discussed in more detail below: 1) storage in depleted oil and natural gas reservoirs, in some instances following EOR/EGR activities; 2) storage in deep saline formations; 3) storage in salt caverns; and 4) adsorption within coalbeds unminable because of depth, thickness or other economic factors. In addition, there is the possibility of other storage options such as organic shales, fractured basalts, and hydrates.

Depleted oil and natural gas reservoirs have demonstrated trapping mechanisms and it can be reasonably assumed they will provide confinement for CO_2 storage. In addition to CO_2 storage, use of depleted oil reservoirs may also have the potential for additional EOR as a result of CO_2 injection if CO_2 EOR has not already been used. Deep saline formations represent potentially very large storage capacities for CO_2. However, the saline formations' lack of demonstrated ability to confine a fluid, which is demonstrated in oil and natural gas reservoirs, will require additional research and site-specific evaluation to determine suitability for storage. With respect to coalbeds, storage in deep unminable coalbeds will be dependent upon the coalbed's ability for absorption of injected CO_2. In addition, the injection of CO_2 into coalbeds may result in increased natural gas recovery by displacing methane as CO_2 is adsorbed (ECBMR).

In addition to the analogues discussed above, there exists in the United States and Canada a large body of state and federal regulations dealing with injection well operations, well construction, and integrity testing for injection. Groups such as the American Petroleum Institute (API), the American Gas Association (AGA), and the American Society for Testing and Materials (ASTM) have established materials selection standards for well casing and down hole equipment, wellhead equipment, cement types, and other relevant oil field equipment and facilities. These well-established regulations and oil field standards will adequately address materials standards for CCGS.

3.3.1.1 Depleted Oil and Natural Gas Reservoirs

Many regions of the U.S. and world have produced oil and natural gas from geologic traps that represent a substantial reservoir capacity available for storage of CO_2. Where these reservoirs are below 3,000 feet, they offer tremendous pore volume space for supercritical CO_2 injection and storage. By their very nature these geologic traps, hosting confined accumulations of oil and natural gas, have proven their ability to contain fluids and gas. Additionally, if storage pressures of CO_2 stay below original reservoir pressures and there is integrity of existing wellbores, there should be no leakage.

3.3.1.2 Saline Formations

Deep saline formations, unlike oil and natural gas reservoirs, may not have demonstrated confining mechanisms but provide potentially large storage capacities for CO_2. Detailed site-specific analyses will be required to determine suitability for storage of CO_2. Early testing of saline reservoir storage options will likely be where the CO_2 is contained within a geological structure and can be readily monitored for a period of time. The ultimate ability of saline reservoirs to store CO_2 is based upon four functions: 1) supercritical CO_2 will be contained within the formation in the form of a buoyant fluid; 2) CO_2 from the injected plume will dissolve in formation water; 3) CO_2 will react with minerals in the host formation to create stable mineral phases; and 4) as injected CO_2 migrates within the host formation, a residual saturation will be created that remains trapped within the pore space. Geochemical interactions, which may result in fixing the CO_2 within the formation, may also cause chemical reactions which could adversely affect the injectability into the reservoir and possibly also the integrity of the reservoir seal. Ongoing research, including reservoir modeling, by the Regional Carbon Sequestration Partnerships is evaluating the potential for CO_2 storage in saline formations.

Experience with injection into saline formations comes from the natural gas storage industry, from acid gas injection, and from assessments made to support the underground injection of hazardous wastes. The U.S. currently has about 1.23 trillion cubic feet (Tcf) of natural gas storage capacity developed in 38 aquifer fields. These fields are typically cycled on an annual basis with injection in the summer and withdrawal to meet winter heating demand. Understanding gained – particularly regarding seal integrity, chemistry of formation brines, behavior of the aquifer in terms of fluid flow, and influence of reservoir heterogeneities – can be transferred to an understanding of CO_2 storage in saline reservoirs. Gupta and others (2001) estimate that just one saline formation in the Midwestern U.S., the Mt. Simon Sandstone, has a storage capacity of 160 to 800 Gt of CO_2, but much site-specific work remains to be done to fully understand the reservoir functions listed above.[60] Others have suggested that the saline reservoir storage capacity in the U.S. as a whole may be up to 500 Gt.[61]

3.3.1.3 Salt Caverns and Others

The technology and regulatory framework for storage of natural gas in salt caverns is well established and with appropriate adaptations and modifications, is readily applicable to storage of CO_2. Current regulatory requirements for salt cavern gas storage facilities generally include comprehensive site characterization and suitability analysis; facility design, construction, operation, and maintenance criteria, including provisions related to cavern integrity, operating pressures, and other conditions; well design, drilling, construction, and operation; monitoring,

[60] Gupta, N., Wang, P., Sass, P., Bergman, P., and Byrer, C., 2001, Regional and site-specific hydrologic constraints on CO2 sequestration in the Midwestern United States saline formations: Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies, CSIRO Publishing, pp. 385-390.
[61] Bergman, P.D. and Winter, E.M., 1995, Disposal of carbon dioxide in aquifers in the U.S.: Energy Conversion and Management, v. 36, pp. 523-526.

measurement, and verification (MMV); safety and environmental protection; and abandonment and restoration.

Many, if not most, of the rules and regulations which states apply to the storage of natural gas in salt caverns are relevant to the storage of CO_2. However, in some states, salt cavern CO_2 storage may not be allowed under the existing regulatory framework. For example, under Alabama's rules and regulations for storage of gas in solution-mined cavities, gas is defined as "...all natural gas, casinghead gas, and occluded natural gas found in coalbeds, and all other hydrocarbons not defined as oil…except and not including liquid petroleum gas." Therefore, in this situation, CO_2 is not included under the definition and the rules would require modification to allow the storage of CO_2 in salt caverns.

Further, current rules and regulations generally do not take into account long-term storage in salt caverns. In general, when a facility is abandoned, gas is recovered and the gas injection wells are plugged according to specified requirements. Modifications to address permanent monitoring of facilities to assure integrity and safety will need to be incorporated into current rules and regulations.

3.3.1.4 Enhanced Coalbed and Organic Shale Methane Recovery

The development of methane production from coalbeds – coalbed methane (CBM) – is a relatively new source of natural gas, growing from reserves of 5.1 Tcf and production of 196 Bcf in 1990 to reserves of 18.7 Tcf and production of 1,600 Bcf in 2003.[62] Coalbed methane accounted for about 8% of U.S. natural gas production in 2002.[63] Production of methane from coalbeds requires depressurizing the seams by pumping off the formation water to allow desorption of methane from the coal

[62] Energy Information Administration, Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, p. 17 2004.
[63] Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, September 2004, DOE/EIA-0216 2003, at: http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2003/adsum2003.pdf

matrix. Given that coal has an affinity for CO_2 adsorption and that CO_2 can preferentially adsorb onto the coal resulting in a release of methane, exposure of coalbeds to injected CO_2 is a likely means to enhance CBM production, a process termed ECBM. If CO_2 was injected and retained in unminable coalbeds, enhanced natural gas supplies may result in the process of storing CO_2. Several pilot projects concerning CO_2 injections into coal to enhance methane recovery have been initiated.[64]

3.3.1.5 Other Storage Options

Other storage options, including organic shales and basalts, are currently under study and may provide specialized storage options. Additional studies will determine the viability of these applications. However, regulatory frameworks could utilize experience gained in other storage options but would require new regulations applicable to new processes and new host geologic formations.

3.3.2 Injection Regulatory Recommendations

Injection and storage of CO_2 effectively incorporates the experience base of CO_2 EOR, Natural Gas Storage, and acid gas injection. These commercial activities have had a long history of operations, and analogues to CO_2 injection abound. The one feature overlaid upon the three bodies of experience is long-term containment assurance. State agencies have a long and successful history of regulating the

---

[64] One important experiment has been completed and two are underway with respect to ECBM. In the San Juan Basin, New Mexico, 280,000 tons of CO_2 were injected over six years to assess the absorption capacity of the coal. Based on the conditions at the Allison Unit, the added recoverable methane can offset costs of CO_2 capture and transportation on the order of $2-5/ton of CO_2. Reeves, S., Taillefert, A., and Clarkson, C., The Allison Unit CO_2 – ECBM Pilot: A Reservoir Modeling Study, U.S. Department of Energy, Award Number DE-FC26-0NT40924 (2003). In another project, Consol Energy has drilled several horizontal wells at a test site in West Virginia and will test the injection of 26,000 tons of CO_2 over a one-year period. U.S. Department of Energy, Carbon Sequestration Project Portfolio, Office of Fossil Energy, National Energy Technology Laboratory, p. 305 2004. In Europe, the RECOPOL project involves CO_2 injection into coals in the Upper Silesian coal basin of Poland. Pagnier, H. and van Bergen, F., Netherlands Institute of Applied Geoscience TNO, National Geographic Survey, CO_2 Storage in Coal: The RECOPOL Project, at: http://www.coal-seq.com/Proceedings/FrankVanBergen-CO2-Presentation.pdf

injection of fluids and gasses into the subsurface under the Underground Injection Control (UIC) Program under the Federal Safe Drinking Water Act.[65] Those states which have CO_2 injection wells for EOR purposes, and which have primacy under the UIC program, currently regulate these wells as Class II wells. As concerns non-EOR CO_2 injection wells, the Task Force has concluded, given the commodity status of CO_2 in the market and utilizing the natural gas storage analogue, that future CCGS projects should be regulated under state natural gas storage statutes and existing regulatory frameworks.

The states' natural gas storage statutes and regulations include the necessary components – such as reservoir selection, injection and withdrawal parameters, unauthorized gas releases, and pressure limitations – all of which can be adapted to CCGS projects.

Given the regulatory experience of the states and provinces in the area of CO_2 EOR, natural gas storage and acid gas injection, future CO_2 regulations should build upon the regulatory frameworks already tested and in place in state and provincial statutes and regulations. In addition, given the commodity status of CO_2, which is akin to natural gas storage as a commodity, future CO_2 regulation not involving EOR projects, which are currently regulated under UIC programs, should be regulated as natural gas storage projects utilizing the framework of existing state and provincial statutes and regulations.

As concerns non-EOR injection wells, the Task Force acknowledges that EPA may recommend application of the UIC to such non-EOR CO_2 injection wells. The Task Force suggests that EPA, before it makes any recommendation concerning UIC applicability to non-EOR CO_2 injection, work closely with states.

[65] 42 U.S.C. § 300h.

Specific recommendations are included below:

- Require clarity and transparency in all statute and regulation development.
- States with Oil and Natural Gas Conservation Acts and with existing CO_2 injection related to EOR projects or future ECBM and EGR, currently regulate these projects under UIC programs.[66] These existing regulatory frameworks provide a successful analogue for CCGS and should be examined as to whether they will adequately address the unique properties of CCGS in depleted oil and natural gas reservoirs dealing with well construction, casing, cementing, and well abandonment. To the extent necessary, these statutes and regulations should be modified to include geologic storage as suggested in the IOGCC Model Conservation Act.[67] States without experience in CO_2 EOR can look to those states with ongoing CO_2 EOR projects whose statutes and regulations have proven to be successful.
- States and provinces with natural gas storage statutes should utilize their existing natural gas regulatory frameworks, with appropriate modifications, for CCGS as suggested in a Conceptual Framework for a CO_2 Geological Statute that can be found in Appendix 6. Those states without experience can look to the referenced conceptual framework or other states whose regulations have proven successful. Should EPA recommend that injection of CO2 for non-EOR purposes be regulated under the UIC program, the Task Force strongly recommends reclassifying such wells either as a subclass of Class II or a new classification. The Task Force strongly believes that inclusion of non-EOR CCGS wells under Class I or Class V of the UIC program would not be appropriate.
- States and provinces with regulations for acid gas injection should utilize their regulatory frameworks, with appropriate modifications, for CCGS.

---

[66] Similarly, in Canada CO_2 injection for EOR or ECBM operations is regulated under provincial Oil and Natural Gas Conservation Acts.
[67] The IOGCC Model Conservation Act can be found at the IOGCC Web site at: http://iogcc.state.ok.us/COMMPGS/FinalModelAct.pdf

- Regulations governing permitting processes should adequately address reservoir properties relative to the interaction of CO_2 with rock matrix and reservoir fluids. For example, carbonate precipitation is an unknown factor where there is CO_2 exposure within the reservoir over a long period of time. Further study is needed to define this issue.
- Well and equipment operational regulations should take into account the unique properties of CO_2. For example, CO_2, when exposed to water, forms carbonic acid, which is corrosive to oil field equipment and cement. Further study is needed to define the scope of the issue from the standpoint of standards and regulations.
- Regulations governing permitting processes for non-EOR CO_2 injection projects should respect existing property rights dictated by state law in issuing CO_2 storage site permits.
- Existing monitoring regulations currently in use for CO_2 EOR, natural gas storage, and acid gas injection may not adequately address monitoring and verification requirements for CO_2 storage to ensure injected CO_2 is accounted for. These regulations will need to be amended to ensure that the CCGS is performing as expected relative to safely storing CO_2 away from the atmosphere, accounting for those volumes, and establishing leak detection protocols.
- Review existing CO_2 EOR, natural gas storage, and acid gas regulations to ensure that operational plans for addressing public health and safety, as well as release or leakage mitigation procedures, are adequate.
- Adapt and modify established permitting regulations and standards for site characterization for purposes of CCGS. Consider results of DOE-sponsored partnership research and other ongoing research.
- Involve all stakeholders, including the public, in the rule making process at the earliest possible time.

3.4 Post-Injection Storage

Post-Injection Storage is defined as storage in depleted oil and natural gas reservoirs (including terminated CO_2 EOR projects), saline aquifers, salt caverns, and unminable coalbeds.

3.4.1 Post-Injection Technical Issues

The licensing and permitting process for CCGS projects is designed to establish suitability and capability of a potential geologic storage structure to confine CO_2. The permitting process developed for EOR projects and natural gas storage projects contains reservoir characterization elements which should be reviewed to ensure that they properly address CCGS issues. Following completion of the injection phase, a regulatory framework needs to be established to address monitoring and verification of emplaced CO_2, leak mitigation for the stored CO_2, and determination of long-term liability and responsibility.

The oil and natural gas regulatory framework does provide some guidance on the issue of long-term liability. In some states and provinces, the last oil and natural gas operator of record would be held as the responsible party following final closure of an active oil and/or natural gas project. This model may or may not provide guidance for assessing future liability for CCGS projects. In most oil and natural gas producing states and provinces where a responsible party cannot be established by regulation or is no longer in business, the state or provincial government assumes responsibility for plugging abandoned wells and remediating or restoring associated production facilities. Whether this framework can serve as a model for the liability issue of long-term CCGS is a subject for discussion.

3.4.2 Post-Injection Storage Regulatory Recommendations

Abandoned underground natural gas storage fields provide the closest analogy to projected CO_2 storage reservoirs. The difference, however, lies with the fact that abandoned natural gas storage fields are usually blown down prior to closure, thus reducing substantially the bottom hole pressure, whereas CO_2 storage reservoirs are projected to be pressured up throughout the storage time frame. The EOR model provides a technical, economic and regulatory pathway for long-term CO_2 storage, but the sparsity of post-injection EOR projects has not provided adequate guidance for a CO_2 storage framework. Consequently, a new framework will need to be established to address the long-term monitoring and verification of emplaced CO_2 and determination of long-term liability.

During the operational phase of the CO_2 storage project the responsibility and liability for operational standards, release, and leakage mitigation lies with either the owner of the CO_2, established through contractual or credit arrangements, and/or the operator of the storage facility. Long-term ownership (post-operational phase) will remain with the same entities.

However, given the nonpermanence of responsible parties, detailed examination of long-term oversight of CCGS projects will be necessary. This examination will require creation of specific provisions regarding financial responsibility in the case of insolvency or failure of the licensee. These options may include establishment of:

1. Surety bonds
2. Insurance Funds
3. Government Trust Funds
4. Public, Private or Semi-Private Partnerships

Specific recommendations are included below:

- Require clarity and transparency in all statute and regulation development.
- Consider the potential need for legislation to clarify and address the unknown issues which may arise in the ownership of storage rights (reservoir pore space) and payment for use of those storage rights.

- Research the chemical transformations that are likely to take place in the reservoirs over long periods of time which may impact, positively or negatively, reservoir integrity in CO_2 storage time frames. Some work has already been done in this area.[68]
- Construct a regulatory framework for the storage stage that allows for the potential of future removal of CO_2 for commercial purposes.
- Given the long time frames proposed for CO_2 storage projects, innovative solutions to protect against orphaned sites will need to be developed. The current model utilized by most oil and natural gas producing states and provinces – whereby the government provides for ultimate assurance in dealing with orphaned oil and natural gas sites – may provide the only workable solution to this issue. This can be accomplished through state and provincial government administration of federally guaranteed industry-funded abandonment programs.
- Establish technical standards for well abandonment and site closure accounting for specialized concerns dealing with the unique properties of CO_2 impacts on reservoir characteristics, well construction, and cementing techniques normally used in the oil and natural gas industry.
- Establish procedures for long-term reservoir management and monitoring. A new framework will need to be established to address the long-term monitoring and verification of emplaced CO_2 to confirm that injected volumes remain in place.
- Establish a regulatory threshold requiring mitigation procedures to be initiated.
- Involve all stakeholders, including the public, in the rule making process at the earliest possible time.

---

[68] *See*: White S.P., Allis R.G., Bergfeld D., Moore J.N., Chidsey T.C., Morgan C., McClure K., Adams, M., Rauzi S., "Evaluating the Seal Integrity of Natural CO_2 Reservoirs of the Colorado Plateau," Proceedings of the Third Annual Carbon Capture & Sequestration Conference, May 3-6, 2004, at the Mark Center Hilton Hotel in Alexandria, VA, U.S. Department of Energy National Energy Technology Laboratory.

List of Figures

Nomenclature

Abbreviations:	Description:
AASG	Association of American State Geologists
AGA	American Gas Association
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
bcfd	Billion cubic feet per day
bbl	Barrel
CBM	Coalbed Methane
CCGS	Carbon Capture and Geologic Storage
CCS	Carbon Capture and Storage
CFC	Chlorofluorocarbons
CH_4	Methane
CO_2	Carbon Dioxide
CO_2CRC	Carbon Dioxide Cooperative Research Centre, Australia
CRC	Canyon Reef Carriers
Degrees C	Degrees Celsius
Degrees F	Degrees Fahrenheit
DOE	U.S. Department of Energy
ECBMR	Enhanced Coalbed Methane Recovery
EGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
FAA	U.S. Federal Aviation Administration
FEMA	U.S. Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
Ft	Feet
Gt	Gigatons (billion metric tons)
H_2O	Water
H_2S	Hydrogen Sulfide
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
Kbopd	Thousands of barrels of oil per day
Mcf	million cubic feet
MMV	Monitoring, Measurement, and Verification

Abbreviations:	**Description:**
Mt (No period)	Megatons (million metric tons)
Mt. (period)	Mount
NaCl	Sodium Chloride
NETL	National Energy Technology Laboratory
NIOSH	National Institute for Occupational Safety and Health
NO_2	Nitrous Dioxide
NO_x	Nitrogen Oxides
O_3	Ozone
OSHA	U.S. Occupational Health and Safety Administration
Ppm	parts per million
Psi	pounds per square inch
Scf	Standard cubic foot
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxides
Tcf	Trillion cubic feet
UIC	Underground Injection Control
U.S.	United States

Appendices

Appendix 1	Participants in IOGCC Geological CO_2 Sequestration Task Force
Appendix 2	State and Provincial Regulatory Frameworks for Carbon Dioxide
Appendix 3	NETL CO_2 Capture Technology Literature
Appendix 4	North American CO_2 Pipelines
Appendix 5	State References for Pipeline & Natural Gas Storage Regulations
Appendix 6	Conceptual Framework for a CO_2 Geological Storage Statute

Appendix 1

Participants in IOGCC Geological CO2 Sequestration Task Force

1. Lawrence Bengal, Chairman
   Arkansas Oil and Gas Commission

2. Robert Finley (An Assessment of Geological Carbon Sequestration Options in the Illinois Basin Partnership), Vice-Chairman
   Illinois State Geological Survey

3. Mike Stettner
   California Division of Oil and Gas and Geothermal Resources

4. Charles Mankin
   Oklahoma State Geological Survey

5. Steven Seni
   Texas State Railroad Commission

6. Lynn Helms
   North Dakota Industrial Commission

7. Doug Patchen
   University of West Virginia

8. Dave Bassage
   West Virginia Department of Environmental Protection

9. Stephen Melzer
   Consulting Petroleum Engineer

10. Morris Korphage
    Kansas Corporation Commission

11. John King
    Michigan Public Service Commission

12. Lawrence Wickstrom
    Ohio Geological Survey

13. Timothy Carr
    Kansas Geological Survey

14. John Harju (Plains CO2 Reduction Partnership)
    North Dakota Energy and Environmental Research Center

15. Jack Ford (Southwest Regional Partnership for Carbon Sequestration)
    New Mexico Department of Energy, Minerals & Natural Resources

16. Patrick Esposito II (Southeast Regional Partnership for Carbon Sequestration)
    Augusta Systems

17. Raymond Lawton (Midwest Regional Carbon Sequestration Partnership)
    Ohio State University

18. Jean Young (West Coast Regional Carbon Sequestration Partnership)
    Terralog Technologies USA, Inc.

19. Susan Capalbo (Big Sky Regional Carbon Sequestration Partnership)
    Montana State University

20. David Hyman
    National Energy Technology Laboratory

21. Nick Tew
    Alabama State Oil and Gas Board

22. Daniel Seamount
    Alaska Oil and Gas Conservation Commission

23. Stefan Bachu
    Alberta Energy and Utilities Board

24. Christine Hansen
    Interstate Oil and Gas Compact Commission

Administrative:

Kevin J. Bliss, IOGCC Project Coordinator
Bill LeMay, IOGCC Task Force Regulatory Expert

Appendix 2

State and Provincial Regulatory Frameworks for Carbon Dioxide

State	Has State defined CO2?		Is CO2 Being Injected?	If Yes, Reason	Under What Regulatory Authority ?	Long Term CO2 Storage-How would State Regulate ?	Is State Considering New Laws?	Gas Storage Regulatory Authority? (UIC, Non UIC)
	Yes	No						
Alabama		X	Yes	EOR	UIC - Class II	Underground gas storage	No	non UIC
Alaska		X	Yes	EOR	UIC - Class II	Gas storage & UIC Class II	No	UIC
Arizona		X	No			Aquifer Protection Permit	No	UIC & non UIC
Arkansas		X	Yes	EOR	UIC - Class II	New Authority OGC&DEQ	No	No Response
California	X, motor vehicle		Yes	EOR	UIC - Class II	DOGGR&SWRCB under MOU	No	UIC & non UIC
Colorado		X	Yes	EOR	UIC - Class II	Under EPA Class I or V	No	UIC
Florida		X	No			Underground gas storage	No	UIC & non UIC
Illinois		X	No			UIC Class II	No	non UIC
Indiana		X	No			Underground gas storage	No	No Response
Kansas		X	Yes	EOR	UIC - Class II	Underground gas storage	No	non UIC
Kentucky		X	Not now	past EOR	EPA	UIC Class II	No	No Response
Louisiana		X	Yes	EOR & EGR	UIC - Class II	Underground gas storage	No	UIC
Maryland		X	No Response			No Response	No	non UIC
Michigan		X	Yes	EGR	UIC - Class IIR	Part 625, Mineral wells of NREPA	No	non UIC
Mississippi		X	Yes	EOR	UIC - Class II			non UIC
Missouri		X	No			UIC Class V	No	No Response
Nebraska		X	No			New Authority under O&GCC	No	No Response
Nevada		X	No			New Authority under NDEP	No	No Response
New Mexico		X	Yes	EOR & EGR	UIC - Class II	NMOCD rules and regulations	No	non UIC
New York	X, air pollutant		No			Underground gas storage	No	non UIC
North Dakota		X	Yes-Canada	Exported	NDAC 43-02-01	Underground gas storage	No	No Response
Ohio		X	No			Class II Proposed	Yes	UIC
Oklahoma		X	Yes	EOR	UIC - Class II	OCC regulations pending study	No	UIC
Oregon	No Response		No Response			No Response		UIC & non UIC
Pennsylvania		X	Not now	past EOR	EPA	Pilot project with EPA & DEP	No	No Response
South Dakota		X	No			UIC project under SDDENR	No	No Repsonse
Texas		X	Yes	EOR	UIC - Class II	Probable MOU - RRC & CEQ	No	No Response
Utah		X	Yes	EOR	UIC - Class II	UIC & Gas Storage	No	UIC
Virginia		X	No			UIC program with EPA primacy	Yes DEQ eval.	non UIC
West Virginia		X	Yes	EOR & EGR	UIC - Class II	UIC Disposal; Non UIC Storage`	No	No Response
Wyoming		X	Yes	EOR & EGR	UIC - Class II	Underground gas storage	No	non UIC
Alberta	X		Yes	EOR &Acid Gas	EUB-Class III	Yes, EOR and acid gas	No	EUB
British Columbia		X	No	Acid Gas		Gas Disposal Wells	No	B.C. Oil & Gas Comm.
Saskatchewan		X	Yes	EOR		Gas Injection Wells	No	

Note: Well classification in Canada differs from the United States. Class III in Canada similar Class II in the U.S. EUB: Alberta Energy and Utilities Board. Also, Canadian Regulatory Schemes are different and are not at all related to the EPA or the states. Regulation occurs by the provinces pursuant to their legislation. See also footnote 12 to the Final Report to which this appendix is attached.

Appendix 3

NETL CO_2 Capture Technology Literature

December 6, 2004

1. *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, Palo Alto, CA, U.S. Department of Energy—Office of Fossil Energy, Washington, DC, and U.S. Department of Energy/NETL, Pittsburgh, PA: 2002. 1004483 (http://www.netl.doe.gov/coal/Gasification/pubs/pdf/EpriReport.PDF)

2. *Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal*, EPRI, Palo Alto, CA, U. S. Department of Energy — Office of Fossil Energy, Germantown, MD and U. S. Department of Energy/NETL, Pittsburgh, PA: 2000. 1000316. (http://www.netl.doe.gov/coal/Gasification/pubs/pdf/1004483.pdf)

3. Klara, S.M., Srivastava, R.D., *U.S. DOE Integrated Collaborative Technology Development Program for CO_2*, Environmental Progress, December 2002. (http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/articles/EnvirProgress.pdf)

4. *Evaluation of Fossil Fuel Power Plants with CO_2 Recovery*, U.S. Department of Energy/National Energy Technology Laboratory, Pittsburgh, PA, Parsons Infrastructure and Technology Group, Inc., Contract No. DE-AM26-99FT40465, February 2002 (http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/analysis/Evaluation_of_Fossil_Fuel_Power_Plants_with_CO2_Recovery.pdf)

5. Dipietro, P. J., Tarka, T., Ciferno, J.P., *An Economic Scoping Study for CO_2 Capture using Aqueous Ammonia*, U.S. Department of Energy/National Energy Technology Laboratory, Pittsburgh, PA, Advance Research International, Energetics, Inc., Novemebr 2004 (http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/analysis/Final%20AA%20Systems%20Analysis.pdf)

Appendix 4

North American CO2 Pipelines

Pipeline	Owner/Operator	Length (mi)	Diameter - in	Location
Anadarko Powder River Basin CO_2 PL	Anadarko	125	16	WY
Anton Irish	Oxy	40	8	TX
Bravo	Oxy Permian	218	20	NM,TX
Canyon Reef Carriers	Kinder Morgan	139	16	TX
Centerline	Kinder Morgan	113	16	TX
Central Basin	Kinder Morgan	143	26-16	TX
Chaparral	Chaparral Energy	23	6	OK
Choctaw	Denbury Resources	110	20	MS
Cordona Lake	ExxonMobil	7	6	TX
Cortez	Kinder Morgan	502	30	TX
Dakota Gasification	Dakota Gasification	204	12	ND/Sask
Dollarhide	Pure Energy	23	8	TX
El Mar	Kinder Morgan	35	6	TX
Enid-Purdy (Central Oklahoma)	Anadarko	117	8	OK
Este I - to Welch, Tx	ExxonMobil, et al	40	14	TX
Este II - to Salt Creek Field	ExxonMobil	45	12	TX
Ford	Kinder Morgan	12	4	TX
Joffre Viking	Penn West Petroleum Ltd.	8	6	Alberta
Llano	Trinity CO_2	53	12-8	NM
Pecos County	Kinder Morgan	26	8	TX
Raven Ridge	ChevronTexaco	160	16	WY/Co
Sheep Mountain	British Petroleum	408	24	TX
Shute Creek	ExxonMobil	30	30	WY
Slaughter	Oxy Permian	35	12	TX
Transpetco	TransPetco	110	8	TX
Val Verde	PetroSource	83	10	TX
W. Texas	Trinity CO_2	60	12-8	TX,NM
Wellman	Wiser	25	6	TX
White Frost	Core Energy, LLC	11	6	MI
Wyoming CO_2	ExxonMobil	112	20-16	WY

Reference: Melzer, L.S. , Personal Data Tabulations (2004).

Appendix 5

State References for Pipeline and Natural Gas Storage Regulations

The following is a compendium of state references for pipeline and gas storage regulations based on the responses by the states to a questionnaire submitted by the IOGCC Task Force.

Alabama:

State Oil And Gas Board Of Alabama

Administrative Code

Oil And Gas Report 1

http://www.ogb.state.al.us/HTMLS/ogbrules/OGB_Rules_TOC.htm

Pipeline: Onshore Operations Rule 400-1-8-.03 (Gathering Lines); Coalbed Methane Gas Operations Rule 400-3-7-.03 (Gathering Lines)

Gas Storage Project: Rule 400-5 (Reservoirs); Rule 400-6 (Solution Mined Cavities)

The Code of Alabama 1975

http://www.legislature.state.al.us/CodeofAlabama/1975/coatoc.htm

Pipeline: Title 9, Chapter 17: Article 3 (Gas Pipeline Systems); Article 1 (Conservation and Regulation of Production), specifically Section 9-17-6

Gas Storage Project: Title 9, Chapter 17: Article 6 (Underground Gas Storage)

Alaska:

The Alaska Statutes - 2003

http://www.legis.state.ak.us/cgi-bin/folioisa.dll/stattx03/query=*/toc/{@21}?next

Pipeline: AS 42.06.240

AS 42.06.310

AS 09.55.240

Gas Storage Project: AS 31 (New Regulations would have to be written)

Arizona:

Arizona Revised Statutes

http://www.azleg.state.az.us/ArizonaRevisedStatutes.asp

Pipeline: A.R.S. 40-441, 40-442, 40-443, and 49-1001

Gas Storage Project: A.R.S. 27-516(A)(20)

A.R.S. 49-241.01

Arkansas:

http://www.arkleg.state.ar.us/NXT/gateway.dll?f=templates&fn=default.htm&vid=blr:code

Pipeline: Arkansas Pipeline Saftey Act

Arkansas Code Annotated Sections 23-15-201 thru 217

Gas Storage Project: Arkansas Underground Storage of Gas Law

Arkansas Code Annotated Sections 15-72-601 thru 608

California:

California Code of Regulations (CCR)

Title 14, Division 2, Chapter 4

http://www.consrv.ca.gov/DOG/pubs_stats/law_regulations.htm

Pipeline: Subchapter 2, Article 3, Section 1774

Gas Storage Project: Subchapter 1, Article 3, Section 1724.9

Colorado:

Colorado Revised Statutes

http://www.state.co.us/gov_dir/olls/HTML/colorado_revised_statutes.htm

Pipeline: including but not limited to C.R.S 7-43-102 and 40-1-103

Gas Storage Project: C.R.S. 34-60-101 through 107

Florida:

The 2004 Florida Statutes

http://www.flsenate.gov/Statutes/index.cfm?Mode=View%20Statutes&Submenu=1&Tab=statutes

Pipeline: Chapter 368 and 377

Gas Storage Project: Chapter 377.242(3)

Georgia:

No Response

Idaho:

No Response

Illinois:

Illinois Compiled Statutes

www.ilga.gov/legislation/ilcs/ilcs2.asp?chapterID=23

Pipeline: 220 ILCS 15 Illinois Gas Storage Act

Gas Storage: 220 ILCS 20 Illinois Gas Pipeline Safety Act

Indiana:

The Indiana Statutes

http://www.in.gov/legislative/ic/code/

Pipeline: IC 8-1

Gas Storage Project: IC 14-37

Kansas:

The Kansas Statutes

http://www.kslegislature.org/cgi-bin/statutes/index.cgi

Pipeline: K.S. 66-1,150

K.S. 66-1,153

Gas Storage Project: K.S. 55-12

K.S. 74-623

K.S. 55-1,115

K.S. 65-171d

K.S. 55-1,117

Kentucky:

No Response

Louisiana:

Louisiana Laws-Revised Statutes

http://www.legis.state.la.us/tsrs/search.htm

Pipeline: LA R.S. 30:501 et seq.

Gas Storage Project: Title 30: LA R.S. 30:23

Maryland:

Pipeline: N/A

Gas Storage Project: Article 14-101

Michigan:

Pipeline: ACT 9PA1929

ACT 165PA1969

Gas Storage Project: ACT 238PA1923

ACT 9PA1929

ACT 165PA1969

ACT 451PA1994

Mississippi:

Mississippi Code of 1972 (As Amended)

http://www.mscode.com/free/statutes/53/001/0017.htm

Pipeline: Not Available

Gas Storage Project: Code Section 53-1-17, Part 3(p)

Missouri:

No Response

Montana:

No Response

Nebraska:

Laws of Nebraska

Nebraska Statutes and Constitution

http://statutes.unicam.state.ne.us/

Pipeline: §57-401 through 402
§57-1101 through 1106
§66-1801 through 1857
§75-501 through 503
§81-542 through 552

Gas Storage Project: §57-601 through 609

Nevada:

Nevada Revised Statutes

http://www.leg.state.nv.us/nrs/nrs%2D708.html

Pipeline: Chapter 708

Gas Storage Project: Not Considered

New Mexico:

New Mexico Statutes and Court Rules

http://www.nmcpr.state.nm.us/nmac/

www.emnrd.state.nm.us./ocd/

Pipeline: NMAC 70.3.A.1 through NMAC 70.3.A.7

Gas Storage Project: NMAC 70.6.A.1 through NMAC 70.6.8

New York:

New York State Consolidated Laws

http://assembly.state.ny.us/leg/?cl=95

Pipeline: Chapter 48 Article 7

Gas Storage Project: Chapter 43-B Article 23 Title 13

North Dakota:

North Dakota Century Code

http://www.state.nd.us/lr/information/statutes/cent-code.html

Pipeline: NDCC 49-02-01.2

Gas Storage Project: NDCC 38-08-04 2. f.

Ohio:

No Response

Oklahoma:

Oklahoma Statutes

-Oklahoma Carbon Sequestration Enhancement Act

-OK Statute Title 27A §3-4-101 through 3-4-105

Oklahoma Administrative Code

Gas Storage Project: OK Admin. Code 165: § 10-3-5

Oregon:

Oregon Revised Statutes - 2003 Edition

http://www.leg.state.or.us/ors/520.html

Pipeline: DOE regulates all above hole well operations pipelines and facilities

Gas Storage Project: ORS 520

Pennsylvania:

No Response

South Carolina:

No Response

South Dakota:

Statutory Titles In South Dakota

http://legis.state.sd.us/statutes/index.cfm?FuseAction=StatutesTitleList

Pipeline: 49-34B

Gas Storage Project: N/A

Texas:

Texas State Statutes

http://info.sos.state.tx.us/pls/pub/readtac$ext.viewtac

http://www.capitol.state.tx.us/statutes/nr.toc.htm

Gas Storage Project: Texas Administrative Code Title 16 Part 1 Chapter 3.96
Natural Resources Code Chapter 91, Subchapter H

Utah:

Utah Code

Utah Administrative Code

http://www.le.state.ut.us/~code/code.htm

http://www.rules.utah.gov/publicat/code.htm

Pipeline: Utah Code 54-13

Rule: R746-409

Gas Storage Project: Utah Code 40-6

Rule: R649-3, R649-5

Virginia:

Code of Virginia

http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+45.1-361.1

Pipeline: 45.1-361.1 et. seq. Title 56

Gas Storage Project: Title 56

Washington:

No Response

West Virginia:

West Virginia Code

http://129.71.164.29/WVCODE/masterfrm3Banner.cfm

Pipeline: WV Code 22-6-30(d)

35 CSR 4-16.7

Gas Storage Project: WV Code 22-9

Wyoming:

2004 Wyoming Statutes

http://legisweb.state.wy.us/statutes/sub30.htm

Pipeline: N/A

Gas Storage Project: Wyo. 30-5-104

Appendix 6

Conceptual Framework For A CO_2 Geological Storage Statute

(Not an IOGCC-approved model statute)

(Although this conceptual framework statute was designed for U.S. states, it is assumed that Canadian provinces could, if desired, easily adapt the document to meet the requirements of their specific jurisdictions and regulatory legislation.)

Preface

The Interstate Oil and Gas Compact Commission (IOGCC) has prepared the following provisions to supplement Part VIII of the Model Oil and Gas Conservation Act, which deals with the regulation of Underground Gas Storage including geologic storage of CO_2. These provisions address the acquisition of properties suitable for geologic storage of CO_2 through eminent domain and recognize certain property rights in stored CO_2. These Model Provisions do not address the initial ownership of CO_2 storage rights vis-à-vis the surface and mineral interest owner. These supplementary provisions should not be codified under a state's conservation act, but Part I should be included in a state's eminent domain or public utilities code and Part II should be included in a state's property code.

Declaration of Purpose

Because of the economic and environmental importance of CO_2, the conservation of property suitable for geologic CO_2 storage, the prevention of waste, and the protection of public health, public safety, and the environment, the geologic storage of CO_2 is declared to be in the public interest. Accordingly, the purpose of these provisions is to conserve property suitable for geologic CO_2 storage, to prevent waste of the storage facility, and to protect correlative rights, public health, public safety, and the environment.

PART I

SECTION 1. DEFINITIONS.

"CCGS operator" means any person, firm or corporation authorized to do business in this state and that holds a certificate of convenience from the [commission] or the Federal Energy Regulatory Commission to engage in the business of transporting, injecting, storing or distributing CO_2 by means of pipelines into, within or through this state for use in enhanced oil and gas recovery, other industrial processes or storage for the purpose of greenhouse gas mitigation.

"CO_2" means CO_2 from an anthropogenic source as a gas or as a supercritical fluid with physical properties between a liquid and a gas at pressures greater than 1073 psi at 87.7 degrees F, and with a purity of 95% or as a constituent in a processed emission stream with commercial value.

"Geologic Storage Facility" means underground geologic formations, strata, reservoirs, or caverns into which CO_2 is injected for storage.

SECTION 2. PUBLIC INTEREST.

The geologic storage of CO_2 provides a mitigation strategy aimed at reducing CO_2 emissions into the atmosphere, which has been shown to be a contributing factor in global warming, thereby promoting the public interest and the general welfare. Therefore, the [legislature of this state] finds that the orderly and efficient geologic storage of CO_2 is in the public interest.

SECTION 3. APPROPRIATION OF CERTAIN PROPERTY.

Any CCGS operator may appropriate for its use for the geologic storage of CO_2 any subsurface stratum or formation in any land which the [oil and gas conservation commission] shall have found to be suitable and in the public interest for the geologic storage of CO_2, and in connection therewith may appropriate other interests in property as may be required adequately to examine, prepare, maintain, and operate geologic storage facilities. The right of appropriation shall be without prejudice to the rights of the owner of the land, minerals, or other rights or interests therein, as to all other uses of property, including the right to drill or bore through the appropriated geologic storage facility, if done in accordance with any order, permit, rule, or regulation that the [oil and gas conservation commission] may issue for the purpose of protecting the geologic storage facility against waste and against the escape of CO_2.

SECTION 4. APPLICATION FOR CO2 GEOLOGIC STORAGE FACILIITY CERTIFICATE; NOTICE AND HEARING; ASSESSMENT OF COSTS.

(a) Any CCGS operator desiring to exercise the right of eminent domain as to any property for use for geologic storage of CO_2 shall, as a condition precedent to the filing of its petition in the district court, obtain from the [oil and gas conservation commission] a certificate setting out findings of the [oil and gas conservation commission] that:

(1) the geologic storage facility sought to be acquired is suitable for the storage of CO_2 and that its use for this purpose is in the public interest; and

(2) the amount of proven commercially producible accumulations of oil or native gas, or both, if any, remaining in the proposed geologic storage facility.

(b) The [commission's] finding under subparagraph (2) above that the geologic storage facility is suitable for the geologic storage of CO_2 shall include specific findings, including:

(1) that the use of the geologic storage facility for CO_2 storage will not contaminate other formations containing fresh water or containing oil, natural gas or other commercial mineral deposits; and

(2) that the proposed geologic storage facility will not unduly endanger lives or property.

(c) the [oil and gas conservation commission] shall not issue a certificate without reasonable notice to interested parties and an opportunity for a hearing. [The applicant shall be responsible for all costs of this proceeding.]

SECTION 5. EMINENT DOMAIN PROCEDURE.

Any CCGS operator having first obtained the certificate specified in [Section 4] from the [oil and gas conservation commission] and desiring to exercise the right of eminent domain for the purpose of acquiring property for the geologic storage of CO_2, shall proceed in accordance with [eminent domain procedure of this state]. The petitioner shall file the certificate as a part of its petition and no order by the court granting said petition shall be entered unless accompanied by the certificate. The appraisers in awarding damages shall also take into consideration the amounts of proven commercially producible accumulations of oil or natural gas or both, if any, remaining in the property sought to be appropriated and, for this purpose, shall receive the findings of the [oil and gas conservation commission] as prima facie evidence of these amounts.

SECTION 6. NOTICE OF CLOSURE OF GEOLOGIC CO_2 STORAGE FACILITY; DISPOSITION OF PROPERTY RIGHTS.

When the owner of a geologic storage facility has ceased active injection operations of CO_2 and closes the storage facility and that facility was certificated by the [oil and gas conservation commission], the owner shall file with the [oil and gas conservation commission] a notice of cessation of injection. If any storage facility was certificated pursuant to federal authority, the owner shall file a copy of any federal closure authority with the [oil and gas conservation commission]. Unless notice of closure authority has been filed with the [oil and gas conservation commission], there shall be a presumption that the geologic storage facility and all rights associated with it remain as certificated. In either case the owner shall file an instrument with the [recorder] in the appropriate county or counties, stating that injection has ceased and that the ownership of all property acquired by the CCGS operator, both mineral and surface, remains with or will be transferred to a successor owner with approval of the [oil and gas commission].

PART II.

SECTION 1. OWNERSHIP OF INJECTED CO_2.

All CO_2 that has previously been reduced to possession, and which is subsequently injected into a geologic storage facility, whether storage rights were acquired by eminent domain or otherwise, shall at all times be the property of the injector, or the injector's heirs, successors or assigns, whether owned by the injector or stored under contract. Absent a final judgment of willful abandonment rendered by a court of competent jurisdiction, in no event shall this CO_2 be deemed the property of a surface owner or mineral owner, or the property of persons claiming by or under these owners, under whose lands the CO_2 is stored. Only the injector, or the injector's heirs, successors and assigns, may produce, take, reduce to possession this stored CO_2.

SECTION 2. EFFECT ON SURFACE AND MINERAL RIGHTS.

Nothing in this subsection shall be deemed to affect the otherwise lawful right of a surface or mineral owner to drill or bore through the geologic storage facilities, if done in accordance with [commission] rules for protecting the geologic storage facility against the escape of CO_2.

SECTION 3. IDENTIFICATION OF MIGRATING CO_2 —COSTS—INJUNCTION.

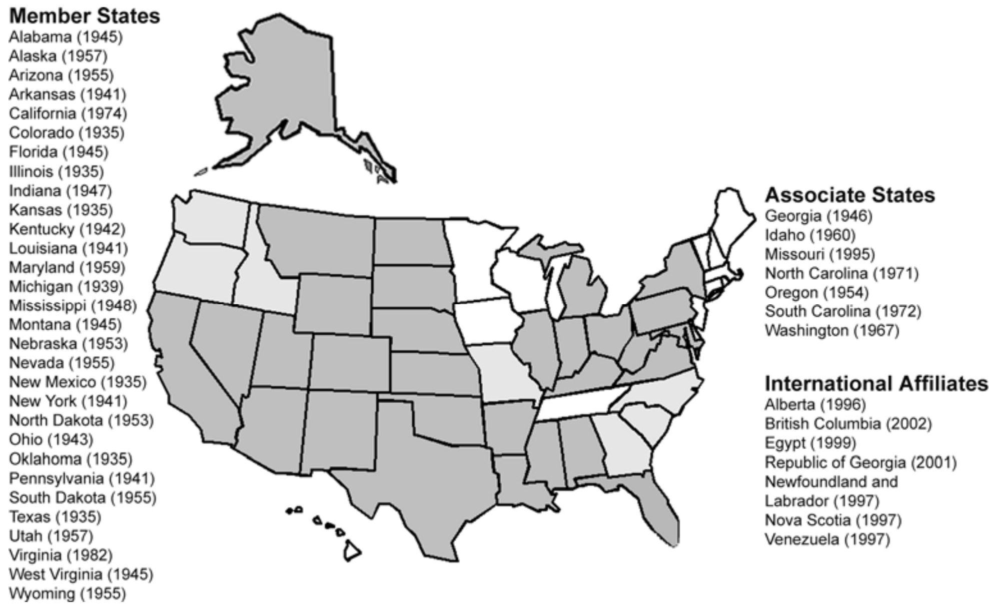
(a) If CO_2 that has been injected into property or has migrated to adjoining property or to a stratum, or portion thereof, which has not been acquired by eminent domain or otherwise acquired, the injector shall not lose title to or possession of injected CO_2 if the injector can prove by a preponderance of the evidence that the CO_2 was originally injected into the geologic storage facility. The court, on its own motion or upon motion of a party, may appoint the [oil and gas conservation commission] as a special master to provide assistance regarding this issue.

(b) If CO_2 that has been injected into property or has migrated to adjoining property or to a stratum, or portion thereof, which has not been acquired by eminent domain or otherwise acquired, the injector, at the injector's sole risk and expense, shall have the right to conduct reasonable testing on any existing wells on adjoining property including tests to determine ownership of the CO_2, and to determine the value of any lost production of other than the injector's CO_2.

(c) If CO_2 that has been injected into property or has migrated to adjoining property or to a stratum, or portion thereof, which has not been acquired by eminent domain or otherwise acquired, the owner of the stratum and the owner of the surface shall be entitled to compensation for use of or damage to the surface or substratum, the value of the storage right, and shall be entitled to recover all costs and expenses, including reasonable attorney fees.

(d) The injector shall have the right to interim relief through injunctive or other appropriate relief.

INSIDE FRONT COVER OF THE PUBLICATION:



The Member and Affiliate States of the Interstate Oil and Gas Compact Commission